BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 100001-EI
FLORIDA POWER & LIGHT COMPANY

SEPTEMBER 1, 2010

IN RE: LEVELIZED FUEL COST RECOVERY
AND CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2011 THROUGH DECEMBER 2011

TESTIMONY & EXHIBITS OF:

G. YUPP
G.F. ST. PIERRE
T.J. KEITH
K. OUSDAHL

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 100001-EI

SEPTEMBER 1, 2010

Q. Please state your name and address.

A. My name is Gerard J. Yupp. 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 Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

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) the dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas; (2) the availability of natural gas to FPL; (3) generating unit heat rates and availabilities; and (4) the quantities and costs of wholesale (off-system) power and purchased power transactions. I also review the interim results of FPL's 2010 hedging program and its 2011 Risk Management Plan. Lastly, I present the projected fuel savings resulting from West County Energy Center Unit 3 (WCEC 3) coming into commercial service on its projected in-service date of June 1, 2011.

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

A. Yes, I am sponsoring the following exhibits:

- GJY-4: Appendix I
- Schedules E2 through E9 of Appendix II

FUEL PRICE FORECAST

Q. What forecast methodologies has FPL used for the 2011 recovery period?

A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve). For light and heavy fuel oil prices, FPL utilizes Over-The-Counter (OTC) forward market prices. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. The forward curves for both natural gas and fuel oil represent expected future prices at a given point in time and are consistent with the prices at which FPL can execute transactions for its hedging program. The basic assumption made with respect to using the forward curves is that all available data that could impact the price of natural gas and fuel oil in the future is incorporated into the curves at all times. The methodology allows FPL to execute hedges consistent with its forecasting method and to optimize the dispatch of its units in changing market conditions. FPL utilized forward curve prices from the close of business on August 2, 2010 for its 2011 projection filing.

Q. Has FPL used these same forecasting methodologies previously?

A. Yes. FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices in 2004 for its 2005 projections.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2011 period?

A. The key factors that could affect FPL's price for heavy oil are (1) worldwide demand for crude oil and petroleum products (including domestic heavy fuel oil); (2) non-OPEC crude oil supply; (3) the extent to which OPEC adheres to their quotas and reacts to fluctuating demand for OPEC crude oil; (4) the political and civil tensions in the major producing areas of the world like the Middle East and West Africa; (5) the availability of refining capacity; (6) the price relationship between heavy fuel oil and crude oil; (7) the price relationship between heavy oil and natural gas; (8) the supply and demand for heavy oil in the domestic market; (9) the terms of FPL's supply and fuel transportation contracts; and (10) domestic and global inventory.

With the global economy projected to continue its slow recovery from the recession, global demand for oil is expected to increase in 2011. Demand in 2011 is forecasted to be 1.8% above projected 2010 demand and 4.4% above actual 2009 demand. Consistent with this trend, crude oil and refined petroleum product prices, like heavy and light fuel oil, should continue to steadily rise over the 2010 to 2011 period. With non-OPEC production projected to be essentially the same over the 2009 through 2011 period, sufficient OPEC production capacity is expected to be available to meet this projected increase in demand and help moderate the price of oil. A greater-than-expected economic recovery resulting in higher-than-expected oil demand will put upward pressure on price. Conversely, a weaker-than-expected global economic recovery will put downward pressure on the price of oil.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2011 period.

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

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

A. The key factors are similar to those described for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2011 period.

A. FPL's projection for the system average dispatch cost of light oil, by month, is provided on page 3 of Appendix I.

Q. What is the basis for FPL's projections of the dispatch cost of coal for St. Johns' River Power Park (SJRPP) and Plant Scherer?

A. FPL's projected dispatch costs for both plants are based on FPL's price projection for spot coal, delivered to the plants.

Q. Please provide FPL's projection for the dispatch cost of SJRPP and Plant Scherer for the January through December 2011 period.

A. FPL's projection for the system average dispatch cost of coal for this period, by plant and by month, is shown on page 3 of Appendix I.

Q. What are the factors that can affect FPL's natural gas prices during the January through December 2011 period?

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

Similar to oil, the major driver for natural gas prices during the remainder of 2010 and all of 2011 revolves around economic recovery and an associated increase in demand as well as domestic natural gas production, particularly from shale sources. Future prices reflect this expectation of economic recovery. Although natural gas prices fell dramatically in 2009 as demand dropped, particularly in the industrial sector, demand in 2010 is projected to be 2.3% over 2009 actual levels and 2011 is forecasted to be 0.6% over 2010. Although the number of working natural gas rigs is down almost 40% since August 2008, domestic production from unconventional sources has and is projected to continue to create ample supply to meet the expected increases in demand. In addition, natural gas storage is projected to continue to be at historical high levels through the 2010 injection season.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December 2011 period?

A. The key factors are (1) the capacity of the Florida Gas Transmission (FGT) pipeline into Florida; (2) the capacity of the Gulfstream Natural Gas System (Gulfstream) pipeline into Florida; (3) the portion of FGT and Gulfstream capacity that is contractually committed to FPL on a firm basis each month; and (4) the natural gas demand in the State of Florida.

The current capacity of FGT into the State of Florida is approximately 2,300,000 MMBtu/day and the current capacity of Gulfstream is approximately 1,100,000 MMBtu/day. In the spring of 2011, FGT's total capacity into the State of Florida will increase by approximately 820,000 MMBtu/day as its Phase VIII expansion is expected to be completed and put into service. FPL has acquired 400,000 MMBtu/day of additional firm natural gas transportation on FGT as part of this expansion. After the completion of the Phase VIII expansion, FPL's total transportation capacity on FGT will range from 1,150,000 to 1,274,000 MMBtu/day, depending on the month. In an effort to support the acquisition of this additional transportation capacity, FPL recently entered into a five-year agreement for 200,000 MMBtu/day of firm transportation capacity on the Transcontinental Pipe Line Gas Company, LLC (Transco) Zone 4A lateral. This firm transportation capacity will give FPL access to shale gas supply at Transco's Station 85, which will further diversify FPL's portfolio and help enhance the reliability of supply with additional on-shore sources. FPL will be able to deliver gas into FGT or Gulfstream via the Transco Zone 4A lateral. Additional upstream opportunities to support the remaining 200,000 MMBtu/day are currently being evaluated. FPL's firm transportation capacity on Gulfstream will remain at 695,000 MMBtu/day during the 2011 period. Additionally, FPL has 500,000 MMBtu/day of firm transport on the Southeast Supply Header (SESH) pipeline.

The firm transportation on the SESH and Transco pipelines does not increase transportation capacity into the state, but FPL's firm transportation rights on these pipelines provide FPL access to 700,000 MMBtu/day of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply. FPL projects that during the January through December 2011 period, between 115,000 and 235,000 MMBtu/day of non-firm natural gas transportation capacity (varying by month) will be available into the state. FPL projects that it could acquire some of this capacity, if economic, to supplement FPL's firm allocation on FGT and Gulfstream.

Q. **Please provide FPL's projections for the dispatch cost and availability of natural gas for the January through December 2011 period.**

A. FPL's projections of the system average dispatch cost and availability of natural gas, by transport type, by pipeline and by month, are provided on page 3 of Appendix I.

PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY

Q. Please describe how FPL developed the projected Average Net Heat Rates shown on Schedule E4 of Appendix II.

A. The projected Average Net 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, and/or from the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2011?

A. Yes. This data is shown on page 4 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 period January through December 2011.

Q. **Please describe the significant planned outages for the January through December 2011 period.**

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 2 is scheduled to be out of service from January 3, 2011 until March 26, 2011 or 82 days during the period. Turkey Point Unit 4 is scheduled to be out of service from March 19, 2011 until May 13, 2011 or 55 days during the period. St. Lucie Unit 1 is scheduled to be out of service from August 29, 2011 until December 17, 2011 or 110 days during the period.

Q. **Please list any changes to FPL's fossil generation capacity projected to take place during the January through December 2011 period.**

A. FPL projects to put West County Energy Center Unit 3 into commercial operation on June 1, 2011. This unit will add an additional 1,219 MW of summer capacity and 1,335 MW of winter capacity.

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power and purchased power transactions forecasted for January through December 2011?

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

Q. In what types of wholesale (off-system) power transactions does FPL engage?

A. FPL purchases power from the wholesale market when it can displace higher cost generation with lower cost power from the market. FPL will also sell excess power into the market when its cost of generation is lower than the market. Purchasing and selling power in the wholesale market allows FPL to lower fuel costs for its customers because savings on purchases and gains on sales are credited to customers through the Fuel Cost Recovery Clause. Power purchases and sales are executed under specific tariffs that allow FPL to transact with a given entity. Although FPL primarily transacts on a short-term basis (hourly and daily transactions), FPL continuously searches for all opportunities to lower fuel costs through purchasing and selling wholesale power, regardless of the duration of the transaction. Additionally, FPL is a member of the Florida Cost-Based Broker System (FCBBS). The FCBBS matches hourly cost-based bids and offers to maximize savings for all participants. Currently, the FCBBS is comprised of 11 members, including FPL. FPL can also purchase and sell power during emergency conditions under several types of Emergency Interchange agreements that are in place with other utilities within Florida.

Q. **Please describe the method used to forecast wholesale (off-system) power purchases and sales.**

A. The quantity of wholesale (off-system) power purchases and sales are projected based upon estimated generation costs, generation availability, expected market conditions and historical data.

Q. **What are the forecasted amounts and costs of wholesale (off-system) power sales?**

A. FPL has projected 873,500 MWh of wholesale (off-system) power sales for the period of January through December 2011. The projected fuel cost related to these sales is $40,232,035. The projected transaction revenue from these sales is $52,336,135. The projected gain for these sales is $9,692,706.

Q. **In what document are the fuel costs for wholesale (off-system) power sales transactions reported?**

A. Schedule E6 of Appendix II provides the total MWh of energy, total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) power sales.

Q. What are the forecasted amounts and costs of wholesale (off-system) power purchases for the January to December 2011 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 1,400,595 MWh at a cost of $79,718,309. If FPL generated this energy, FPL estimates that it would cost $106,875,924. Therefore, these purchases are projected to result in savings of $27,157,615.

Q. Does FPL have additional agreements for the purchase of electric power and energy that are included in your projections?

A. Yes. FPL purchases energy under three Unit Power Sales Agreements (UPS) with the Southern Companies. The agreements are comprised of 790 MW of gas-fired, combined cycle generation (Franklin Unit 1-190 MW and Harris Unit 1-600 MW) and 165 MW of coal generation (Scherer Unit 3). The UPS agreements have a term that runs through December 31, 2015. Additionally, FPL has a capacity agreement for 2011 with Southern Power Company (Oleander) for the output of one combustion turbine totaling 155 MW. The Southern Power Company (Oleander) agreement expires on May 31, 2012. FPL also has contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). Additionally, FPL purchases energy from JEA's portion of the SJRPP Units. Lastly, 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 January through December 2011 period.**

A. UPS energy purchases for the period are projected to be 3,106,196 MWh at an energy cost of $128,521,619. The UPS energy projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of SJRPP are projected to be 2,931,727 MWh for the period at an energy cost of $90,728,000. 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, FPL projects purchases of 352,982 MWh at a cost of $2,102,300. These projections are shown on Schedule E7 of Appendix II.

FPL projects to dispatch 13,197 MWh from its capacity agreement with Southern Power Company (Oleander) at a cost of $1,084,274. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, FPL projects that purchases from Qualifying Facilities for the period will provide 4,073,261 MWh at a cost of $153,332,683.

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

A. FPL projects the sale of 378,619 MWh of energy at a cost of $2,446,761. These projections are shown on Schedule E6 of Appendix II.

Q. How does FPL develop the projected energy costs related to purchases from Qualifying Facilities?

A. For those contracts that entitle FPL to purchase "as-available" energy, FPL used its 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 mechanisms prescribed in the contracts are used to project monthly energy costs.

<u>HEDGING/ RISK MANAGEMENT PLAN</u>

Q. Please describe FPL's hedging objectives.

A. The primary objective of FPL's hedging program has been, and remains, the reduction of fuel price volatility. Reducing fuel price volatility helps deliver greater price certainty to FPL's customers.

FPL does not engage in speculative hedging strategies aimed at "out guessing" the market.

Q. Has FPL filed a comprehensive risk management plan for 2011, consistent with the Hedging Order Clarification Guidelines as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its 2011 Risk Management Plan as part of its annual Fuel Cost Recovery and Capacity Cost Recovery Estimated/Actual True/Up filing on August 2, 2010.

Q. Please provide an overview of FPL's 2011 Risk Management Plan.

A. FPL's 2011 Risk Management Plan remains consistent with FPL's overall objectives that I previously described. It addresses Items 1-9 and 13-15 of Exhibit TFB-4, which is required per the Proposed Resolution of Issues approved in Order No. PSC-02-1484-FOF-EI dated October 30, 2002. FPL's 2011 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges during 2011 for its projected fuel requirements in 2012. FPL plans to hedge the percentages of its 2012 projected natural gas and heavy oil requirements over the time periods in 2011 that are described in the plan.

Q. Has FPL filed a Hedging Activity Supplemental Report for 2010, consistent with the Hedging Order Clarification Guidelines, as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its Hedging Activity Supplemental Report for 2010 (January through July) on August 16, 2010.

Q. Have FPL's 2010 hedging strategies been successful in achieving its hedging objectives?

A. Yes. FPL's hedging strategies have been successful in reducing fuel price volatility and delivering greater price certainty to its customers. Additionally, FPL's customers have been able to benefit from the decrease in natural gas prices from the unhedged portion of FPL's portfolio. At the time FPL was placing its hedges for its 2010 projected natural gas and heavy oil requirements, market prices were significantly different than the actual settlement prices that occurred in 2010.

For example, at the beginning of January 2009, the average monthly NYMEX forward price for natural gas for the January through July 2010 time period was approximately $7.247 per MMBtu. At the end of July 2009, the average monthly NYMEX forward price for the January through July 2010 time period was approximately $5.673 per MMBtu. The actual average NYMEX monthly settlement price for this same time period was $4.698 per MMBtu or $2.549 per MMBtu lower than the prices seen in January and $0.975 per MMBtu lower than the prices seen in July. Conversely, heavy oil prices climbed steadily beginning in January 2009 and are currently at nearly twice the level seen in January 2009. As described in the Hedging Order Clarification Guidelines, hedging in the type of market conditions described above for natural gas results in significant lost opportunities for savings in the fuel costs paid by customers; however, this lost opportunity is a reasonable trade-off for reducing customers' exposure to fuel price increases when market conditions change in the other direction. Conversely, hedging in the type of market conditions described above for heavy oil results in savings for customers; however, as previously stated, FPL's hedging objective is to reduce fuel price volatility and deliver greater price certainty.

Q. **Does FPL's projection filing include incremental operating and maintenance expenses with respect to maintaining an expanded, non-speculative financial and/or physical hedging program for the January through December 2011 period?**

A. No. These costs are now being recovered through base rates.

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE ADDITION OF WCEC 3 (IMPLEMENTATION OF STIPULATION AND SETTLEMENT)

Q. You stated earlier in this testimony that FPL is planning on putting WCEC 3 into operation on June 1, 2011. Will the addition of WCEC 3 result in fuel savings to FPL's customers?

A. Yes. This unit's high efficiency will create substantial fuel savings for FPL's customers once it goes into operation. For the June through December, 2011 period, the addition of WCEC 3 will save FPL's customers $98,411,000.

Q. How did FPL calculate the fuel savings associated with the addition of WCEC 3?

A. FPL utilized its POWRSYM model to quantify the fuel savings associated with the addition of WCEC 3. This model is used to calculate the fuel costs that are included in FPL's projection filing. The same forecasted fuel prices and other assumptions that are reflected in the projection filing were used for analyzing the WCEC 3 fuel savings. In order to calculate the WCEC 3 fuel savings, FPL ran two separate production cost simulations, one without WCEC 3 and one with WCEC 3. A comparison of the total system fuel costs from POWERSYM for the two simulations showed that the fuel costs were $98,411,000 lower in the case that included WCEC 3 than in the case without WCEC 3.

Q. In the Stipulation and Settlement that FPL and the intervening parties in Docket No. 080677-EI filed for Commission approval on August 20, 2010, Paragraph 5(c) directs FPL to calculate the fuel savings associated with WCEC 3 as follows: "FPL shall quantify the projected fuel savings associated with the addition of West County Unit 3 through the use of the same computerized simulations of its system and current assumptions and data regarding unit performance, system load, and fuel costs that it employs to project its fuel costs in the fuel cost recovery proceeding to compare the total fuel costs that FPL would incur without the addition of West County Unit 3 to the total fuel costs it will incur with the addition of West County Unit 3." Is your calculation of $98,411,000 in WCEC 3 fuel savings consistent with Paragraph 5(c)?

A. Yes, it is.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GENE F. ST. PIERRE

DOCKET NO. 100001-EI

September 1, 2010

Q. Please state your name and address.

A. My name is Gene F. St. Pierre. 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 in the Nuclear Business Unit as Vice President of Fleet Support.

Q. Please describe your educational background and business experience in the nuclear industry.

A. I received my technical training in the U.S. Navy Nuclear Power Program, serving for six years. I received my Bachelor of Science degree in general studies from the University State of New York and my Masters in Management from Emmanuel College. I also completed the Program for Management Development at Harvard Business School. In 1977, I joined Yankee Atomic Power Station as an Operator, where I remained until 1979 when I joined Public Service Company of New Hampshire at the Seabrook Nuclear

Power Plant (owned by NextEra Energy since 2002). I served in various roles of increasing responsibility at Seabrook until early 2010. My positions included Control Room Operator, Shift Supervisor, Assistant Operations Manager, Station Director and Site Vice President. In February 2010, I was appointed Vice President of Fleet Support. I have accountability for Emergency Preparedness, Nuclear Fuels, Licensing, Performance Improvement, Security and Fleet Training.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's projections of nuclear fuel costs for the thermal energy (MMBtu) to be produced by our nuclear units and the costs of disposal of spent nuclear fuel. I am also updating the status of certain litigation that affects FPL's nuclear fuel costs; plant security costs and new NRC security initiatives; and outage events. Both nuclear fuel and disposal of spent nuclear fuel costs were input values to POWERSYM used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2011 through December 2011.

<u>Nuclear Fuel Costs</u>

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

A. FPL's nuclear fuel cost projections are developed using projected energy production at our nuclear units and their operating schedules, for the period January 2011 through December 2011.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2011 through December 2011.

A. FPL projects the nuclear units will produce 233,788,606 MMBtu of energy at a cost of $0.6326 per MMBtu, excluding spent fuel disposal costs, for the period January 2011 through December 2011. Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 22.

<u>Spent Nuclear Fuel Disposal Costs</u>

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2011 through December 2011 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $19.5 million are provided in Appendix II, on Schedule E-2, starting on page 15 of the Appendix. These projections are based on FPL's contract with the U.S. Department of Energy (DOE), which sets the spent fuel disposal fee at 0.9321 mills per net kWh generated, including transmission and distribution line losses.

Litigation Status Update

Q. Is there currently an unresolved dispute relating to the spent fuel disposal fee?

A. Yes. On April 5, 2010, FPL along with several other utilities and with the Nuclear Energy Institute filed a petition for review against the DOE in the U.S. Court of Appeals for the District of Columbia Circuit to suspend collection of the spent nuclear fuel disposal fee in light of the DOE's decision to terminate the Yucca Mountain spent nuclear fuel disposal project. FPL expects the Court to rule on the petition sometime in 2011.

Nuclear Plant Security Costs

Q. What is FPL's projection of incremental security costs at FPL's nuclear power plants for the period January 2011 through December 2011?

A. FPL presently projects that it will incur $47.4 million in incremental nuclear power plant security costs in 2011.

Q. Please provide a brief description of the items included in this projection.

A. The projection includes maintaining a security force as a result of implementing NRC's fitness for duty rule under Part 26, which strictly limits the number of hours security personnel may work; additional personnel training; maintaining the physical upgrades resulting from implementing NRC's physical security rule under Part 73; and impacts of implementing NRC's rule under Part 73 for Cyber Security. It also includes Force on Force (FoF) modifications at the St. Lucie and Turkey Point nuclear sites to effectively mitigate new adversary tactics and capabilities employed by the NRC's Composite Adversary Force (CAF) as required by NRC inspection procedures.

Q. Has the NRC issued any revisions to the security-related Orders that affect FPL's projection?

A. Yes. On March 27, 2009 the NRC issued a new rule under Part 73.54 of the Code of Federal Regulations that involves the protection of station digital computer, communications systems and networks which would impose significant requirements for monitoring, hardening and responding to cyber intrusions. FPL provided a plan to the NRC in November 2009 that outlined when full implementation will be completed. Full implementation for this new Part 73.54 is scheduled for completion in 2014. Additionally, the Federal Regulatory Energy Commission (FERC) issued an order on March 18, 2010, imposing similar Cyber Security requirements for implementation at additional plant systems that could impact the reliability of the bulk electric system within eighteen months unless an outage is required for items specifically under FERC jurisdiction. The NRC Cyber Security rulemaking and FERC Order costs for 2011 are estimated to be $8.0 million for the St. Lucie and Turkey Point nuclear sites.

Also, in February 2009, the NRC updated the Enhanced Adversary Characteristics (EAC) of the Design Basis Threat (DBT). These enhancements are now being utilized during the triennial FoF inspections performed at the nuclear stations. The DBT is the measure that all nuclear stations are designed to defend against. Some examples of changes are: enhanced intrusion detection, adversary delay barriers, and additional vehicle barriers.

FoF inspections are scheduled on a repeating three year cycle. Consequently, St. Lucie and Turkey Point will receive third round FoF inspections in the 2011-2013 cycle and FPL sites may require additional modifications to ensure successful regulatory inspection conclusions. Adversary Characteristics are constantly being reviewed by the NRC due to the potential change in adversary capabilities. Consequently, future enhancements of nuclear facilities may be required. St. Lucie is currently performing modifications to the site for preparation of the NRC triennial FoF inspection expected in early 2011. The St. Lucie FoF modifications are estimated to be $3.0 million for 2011.

2010 Outage Events

Turkey Point

Q. Has FPL experienced any unplanned outages at its Turkey Point plant in 2010?

A. Yes. In January 2010, a manual reactor trip on Unit 4 was initiated due to Steam Generator level being greater than 75%.

Q. What caused the manual trip on Unit 4?

A. Prior to the reactor trip, both Unit 4 Heater Drain Pumps (HDPs) tripped. Power was stabilized at 93% and the HDPs were restored. However, following the restoration of the HDPs, a Plant Operator observed that the 4A Steam Generator Feed Pump (SGFP) was leaking oil and water from the pump outboard bearing housing and the oil reservoir level was lowering. In response, Control Room Operators manually secured the 4A SGFP, initiating an automatic reactor power reduction. The power reduction caused elevated water levels in the Steam Generators, an expected result of the normal response of the Steam Generator level control system to the automatic power reduction. Level in the 4B Steam Generator exceeded the administrative set point of 75%, prompting the

Reactor Operator to manually trip the Unit 4 reactor. Two root causes were identified while investigating the 4A SGFP oil leak, 1) unresponsive control of seal water injection to the pump outboard bearing caused by a degraded hand-auto controller, and 2) blockage of the 4A SGFP outboard bearing cavity drain.

Q. How many days was the Turkey Point Unit 4 outage due to this issue?

A. The Unit 4 outage was approximately 3 days.

Q. What corrective actions has FPL initiated to avoid this problem in the future?

A. FPL intends to replace SGFP seal water hand-auto controllers later this year for Unit 4 and as a preventative measure in Unit 3. Additionally, a preventative maintenance activity was established to verify the bearing seal cavity drains are clear on a periodic basis.

St. Lucie

Q. Has FPL experienced any unplanned outages at its St. Lucie plant in 2010?

A. Yes. In April 2010, Unit 2 was manually shut down due to the malfunction of the 2B moisture separator reheater (MSR) safety valve.

Q. What caused the 2B MSR safety valve malfunction?

A. The pilot valve spring on the 2B MSR safety valve had broken which caused the valve to lift at normal operating pressure.

Q. How many days was the St. Lucie Unit 2 outage due to this issue?

A. The Unit 2 outage was approximately 7 days.

Q. What corrective actions did FPL initiate to avoid this problem in the future?

A. The affected safety valve pilot valve spring was replaced. As a preventative measure, the three remaining Unit 2 MSR safety valve pilot valve springs were also replaced.

Q. Has FPL experienced any unplanned outages at St. Lucie Unit 1 in 2010?

A. Yes. In April, 2010 while Unit 1 was shut down to perform a scheduled refueling outage, there were several events that delayed the restart of the unit. The events were primarily related to addressing equipment conditions that were discovered during the course of the outage, including:

1. Scheduled activities for replacement of the Fuel Transfer system wheels and subsequent post maintenance testing revealed high running loads. Extensive troubleshooting resulted in replacement of the defective Load Cell to permit off-load of

fuel from the Reactor to support planned scope later into the outage.

2. Reactor Coolant system Alloy 600 mitigation scope was extended due to discovery of additional defective metal during the machining and welding activities. Inspection and removal of these locations was necessary to meet the intent of the NRC commitment for the repair scope planned.
3. During Reactor assembly following the load of new fuel into the Reactor, the #1 Control Rod (CEA) Extension Shaft was damaged and required replacement.
4. Inspection activities following Main Generator bearing replacement discovered a hydrogen leak in the Radial Leads. Safe operation of the Unit necessitated disassembly and replacement of the defective seals before the Generator could be placed in service.
5. During the return of the Feedwater system for Unit restart, a large seawater leak into the Main Condenser occurred. This resulted in extended activities to isolate and repair the source of leakage before Unit restart. Additionally, this event impacted the ability to increase unit power until all contaminants could be removed from the feedwater system.

Q. How many days was the St. Lucie Unit 1 outage extended due to these issues?

A. The Unit 1 refueling outage was extended approximately 25 days.

Q. Did St. Lucie Unit 1 experience an additional unplanned outage as it was returning to service from the refueling outage?

A. Yes. In June 2010, while Unit 1 was in power ascension from the refueling outage, the Unit was shut down when the control element assembly (CEA) controls malfunctioned and released two control rods into a safe position

Q. What caused the control element assembly to malfunction?

A. The malfunction was caused by a fault in the control system. Subsequent inspection and troubleshooting scope identified defective circuitry components.

Q. How many days was the St. Lucie Unit 1 outage due to these issues?

A. The Unit 1 outage was approximately 11 days.

Q. What corrective actions did FPL initiate to avoid this problem in the future?

A. The affected circuitry components were replaced to ensure operational reliability for Unit operation.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 100001-EI

September 1, 2010

Q. Please state your name and address.

A. My name is Terry J. Keith and my business address is 9250 West 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 Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- I present a revised 2010 Fuel Cost Recovery (FCR) estimated/actual true-up amount, which has been updated to include July 2010 actual data and which is incorporated into the calculation of the 2011 FCR Factors.
- I present FCR factors for the period January 2011 through December 2011 based on the traditional factor calculation methodology, which spreads the fuel savings associated with West County Energy Center Unit 3 (WCEC-3) over the entire

calendar year, as well as FCR factors that reflect all of the WCEC-3 fuel savings in the period after WCEC-3 goes into service (projected to be June 1, 2011).

- I present a new activity for possible recovery through the FCR – the Scherer Unit 4 steam turbine upgrade - and associated FCR factors based on both the traditional factor calculation methodology and the calculation methodology based on the Stipulation and Settlement Agreement (the Settlement Agreement) dated August 20, 2010.
- I present a revised 2010 Capacity Cost Recovery (CCR) estimated/actual true-up amount, which has been updated to include July 2010 actual data and which is incorporated into the calculation of the 2011 CCR Factors.
- I present the CCR factors for the period January 2011 through December 2011.
- I present FPL's Nuclear Power Plant Cost Recovery costs to be recovered through the CCR Clause in 2011.
- I present CCR factors for the period June 2011 through December 2011 including an adjustment to recover the portion of the non-fuel revenue requirements equaling the projected fuel savings associated with WCEC-3.
- Finally, I provide on pages 58-59 of Appendix II FPL's proposed COG tariff sheets, which reflect 2011 projections of avoided energy costs for purchases from small power producers and

cogenerators and an updated ten-year projection of FPL's annual generation mix and fuel prices.

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

A. Yes, I have. They are as follows:

- TJK-5 -- Schedules E1, E1-A, E1-B, E1-C, E1-D, E1-E, E2 and E10 based on the traditional factor calculation methodology. TJK-5 also includes Schedule H1, and pages 12-14 and 58-59. These schedules are included in Appendix II.
- TJK-6 -- the entire Appendix III
- TJK-7 -- the entire Appendix IV
- TJK-8 -- the entire Appendix V

Appendix II contains the FCR related schedules based on the traditional factor calculation methodology, with and without the costs associated with the Scherer Unit 4 steam turbine upgrade. Appendix III contains the CCR related schedules, including the calculation of the CCR factors recovering the portion of the non-fuel revenue requirements equaling the projected fuel savings associated with WCEC-3. Appendix IV contains the FCR schedules based on the Settlement Agreement methodology excluding the costs associated with the Scherer Unit 4 steam turbine upgrade. Appendix V contains the FCR schedules based on the Settlement Agreement methodology including the costs associated with the Scherer Unit 4 steam turbine upgrade.

FUEL COST RECOVERY CLAUSE

Q. Has FPL revised its 2010 FCR Estimated/Actual True-up amount that was filed on August 2, 2010 to reflect July actual data?

A. Yes. The 2010 FCR estimated/actual true-up amount has been revised to an under-recovery of $286,129,908, reflecting July 2010 actual data, plus interest. This $286,129,908 under-recovery, plus the 2009 final true-up under-recovery of $8,771,414 results in a net under-recovery of $294,901,322 (see Schedule E1-b, Pages 5 and 6 of Appendix II). This $294,901,322 under-recovery is to be included in the FCR factor for the January 2011 through December 2011 period.

Q What adjustments are included in the calculation of the levelized FCR factors shown on Schedules E1 included in Appendices II, IV and V?

A. The total net true-up to be included in the 2011 FCR factors is an under-recovery of $294,901,322. This amount, divided by the projected retail sales of 102,071,219 MWh for January 2011 through December 2011, results in an increase of 0.2889¢ per kWh before applicable revenue taxes, as shown on Line 26 of Schedule E1, Page 3 of Appendix II. The Generating Performance Incentive Factor (GPIF) Testimony of FPL Witness Carmine A. Priore III, filed on April 1, 2010, calculated a reward of $8,948,495 for the period ending December 2009. In his September 1, 2010 testimony, Mr. Priore presents a refinement that FPL has implemented for calculation of the 2011 GPIF AHNOR targets and recalculation of prior year targets. Implementing this refinement for prior years results in a credit to customers of $832,595 including interest, which is being applied to reduce the 2009 GPIF reward of $8,948,495. The resulting revised 2009 GPIF reward, which is being applied to the January 2011 through December 2011 period is $8,115,900. This $8,115,900 reward, divided by the projected retail sales of 102,071,219 MWh during the projected period, results in an increase of .0080¢ per kWh, as shown on line 30 of Schedule E1, Page 3 Appendix II.

Q. **What is the proposed levelized FCR factor based on the traditional factor calculation methodology?**

A. 4.464¢ per kWh. Schedule E1, Page 3 of Appendix II shows the calculation of this twelve-month levelized FCR factor based on the traditional factor calculation methodology. Schedule E2, Pages 15 and 16 of Appendix II shows the monthly fuel factors for January 2011 through December 2011 and also the twelve-month levelized FCR factor for the period.

Q. **Has the Company developed levelized FCR factors for its Time of Use rates based on the traditional factor calculation methodology?**

A. Yes. Schedule E1-D Page 1 of 2, located on Page 8 of Appendix II, provides a twelve-month levelized FCR factor of 5.084¢ per kWh on-peak and 4.179¢ per kWh off-peak for our Time of Use rate schedules based on the traditional factor calculation methodology. The time of use rates for the Seasonal Demand Time of Use Rider (SDTR) are 5.241¢ (on-peak) and 4.214¢ (off-peak) and are provided on Schedule E-1D, Page 2 of 2, located on Page 9 of Appendix II. The SDTR was implemented pursuant to the Stipulation and Settlement Agreement approved in Docket No. 050045-EI, which incorporates a different on-peak period during the months of June through September.

FCR factors by rate group for the period January 2011 through December 2011 are presented on Schedule E1-E, Page 1 of 2, located on Page 10 of Appendix II. FCR factors by rate group for the SDTR are provided on Schedule E-1E, Page 2 of 2, located on Page 11 of Appendix II.

Q. Were these calculations made in accordance with the procedures approved in predecessors to this Docket?

A. Yes.

FCR RECOVERY OF SCHERER UNIT 4 STEAM TURBINE UPGRADE COSTS

Q. Are you presenting a new activity for possible recovery through the FCR ?

A. Yes. In the testimony of FPL witness Randall LaBauve filed in Docket No. 100007-EI on August 27, 2010, FPL presented an update to its CAIR and CAMR Compliance Project, which is currently being recovered through the Environmental Cost Recovery Clause (ECRC). The update consists of the upgrade of the steam turbine at Plant Scherer Unit 4, in order to offset the loss in unit output resulting from the installation of required pollution control equipment at the generating unit.

Q. Does FPL believe that the Scherer Unit 4 steam turbine upgrade is eligible for cost recovery through the ECRC?

A. Yes. As explained in Mr. LaBauve's testimony, the turbine upgrade is an integral part of the most cost-effective compliance strategy for the CAIR and CAMR Compliance Project and its costs should be recovered through the ECRC. FPL believes that the turbine upgrade is directly analogous to Progress Energy Florida's modular cooling tower project, which the Commission approved for ECRC recovery in Order No. PSC-07-0722-FOF-EI issued in Docket No. 060162-EI on September 5, 2007.

Q. Why is FPL also presenting the Scherer Unit 4 steam turbine upgrade for recovery through the FCR Clause?

A. In an informal meeting held on August 19, 2010 with Staff and the parties to the ECRC and FCR dockets, Staff expressed the view that the turbine upgrade might not qualify for ECRC recovery. FPL disagrees and believes that the turbine upgrade costs should be recovered through the ECRC for the reasons discussed in Mr. LaBauve's testimony. However, FPL also believes that the turbine upgrade would qualify for cost recovery through the FCR Clause in the event that the Commission does not permit ECRC recovery.

Q. Why does FPL believe that the steam turbine upgrade at the Scherer Plant qualifies for recovery through the FCR Clause?

A. In Order No. 14546 issued in Docket No. 850001-EI-B on July 8, 1985, the Commission approved recovery through the FCR Clause of "fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine base rates and which, if expended, will result in fuel savings to customers".

The steam Unit 4 turbine upgrade consists of installing a new high-pressure rotor that is projected to allow the unit to generate approximately 35 MW of additional electric output. FPL, with the assistance of Georgia Power Company, identified the opportunity to implement this upgrade in conjunction with the installation of pollution control equipment on Unit 4 as part of the CAIR and CAMR Compliance Project and thus avoid the imposition of additional environmental compliance requirements that would ordinarily accompany a major modification such as a turbine upgrade. FPL is scheduled to implement the turbine upgrade in early 2012, at the same time that the final installation work is performed for the pollution control equipment, or else in June 2011 if necessary to avoid the application of the US Environmental Protection Agency's new "Tailoring Rule" for greenhouse gasses.

In the absence of the turbine upgrade, the new pollution control equipment at Scherer Unit 4 is projected to reduce the net output of the unit that is available to serve customers by about 35 MW. Because of Scherer Unit 4's low fuel cost, that loss of net output would result in FPL and its customers being subjected to substantial additional fuel costs to generate the equivalent amount of energy from other, more-expensive sources. The 35 MW of additional Unit 4 output that will result from the turbine upgrade will essentially offset the parasitic load of the pollution control equipment and thus will result in substantial fuel savings to FPL's customers compared to operating the unit without the turbine upgrade. In addition, the turbine upgrade will result in an improvement in Unit 4's heat rate of more than 400 Btu/kWh, meaning that the unit will be able to generate electricity more efficiently as well as increasing its output. FPL's economic analysis indicates that the turbine upgrade will result in fuel savings to FPL's customers of approximately $240 million on a net present value (NPV) basis, compared to a cost to FPL for the upgrade of about $7 million.

Q. Order No. 14546 refers specifically to recovery of "fossil fuel-related costs." Why does FPL believe that a turbine upgrade at a coal-fired plant would qualify for such recovery?

A. The order does not define "fossil fuel," but standard dictionary definitions commonly include coal as a fossil fuel. For example, the American Heritage Dictionary of the English Language defines "fossil fuel" to be "a hydrocarbon deposit, such as petroleum, *coal*, or natural gas, derived from living matter of a previous geologic time and used for fuel." (Emphasis added). The efficiency improvement associated with the turbine upgrade will result in lower coal costs for a given level of output, thus directly reducing FPL's costs for fossil fuels.

Furthermore, the Commission has previously interpreted Order No. 14546 to permit recovery of costs incurred at generating units with low fuel costs -- regardless of fuel type -- that increase the output of those units and thus reduce the amount of energy that must be generated from units with higher fuel costs. For example, in Order No. PSC-96-1172-FOF-EI issued in Docket No. 960001-EI on September 19, 1996, the Commission approved recovery of costs associated with the thermal power uprate at FPL's Turkey Point nuclear-powered Units 3 and 4 through the FCR Clause. The Commission approved recovery of that project through the FCR because the estimated fuel savings related to the thermal power uprate at Turkey Point Units 3 and 4 had a NPV of $98 million at a cost of approximately $10 million. In that case, the savings were due to the low cost nuclear fuel replacing higher cost fossil fuel.

In FPL's current request, the turbine upgrade at Scherer Unit 4 will also result in a power uprate and is projected to result in fuel savings of approximately $240 million on an NPV basis at a cost of about $7 million. This is even more cost-effective than the Turkey Point thermal uprate. In the case of the turbine upgrade, the savings are due to the difference between the ability to burn lower cost coal versus higher cost fossil fuel or purchased power, which is precisely analogous to the Commission's rationale for permitting FCR Clause recovery of the Turkey Point thermal uprate costs.

Q. **Order No. 14546 requires that costs for which FCR Clause recovery is sought "were not recognized or anticipated in the cost levels used**

to determine base rates." Was FPL aware of the potential for implementing the Scherer Unit 4 steam turbine upgrade when it prepared its forecasted test year in Docket No. 080677-EI?

A. No. FPL prepared its test year MFRs in late 2008. FPL learned of the potential to pursue the turbine upgrade from discussions with Georgia Power Company in the summer of 2009, applied for a permit from the Georgia Environmental Protection Division in late December 2009, and received the permit in February 2010. FPL could not have reasonably anticipated the turbine upgrade as part of the rate case in Docket No. 080677-EI.

Q. How does FPL propose to recover the 2011 costs of the Scherer Unit 4 steam turbine upgrade through the FCR Clause?

A. FPL proposes to recover the depreciation and return on investment associated with the cost of the Scherer Plant Unit 4 steam turbine upgrade through the FCR. For 2011, this amount is $342,418. The calculation of depreciation and return on investment for the Scherer Unit 4 steam turbine upgrade is included in Appendix II, Pages 61 and 62..

Q. What is the levelized FCR factor for January 2011 through December 2011 based on the traditional methodology, including costs associated with the Scherer Unit 4 steam turbine upgrade?

A. Due to the relatively small dollar amount to be recovered in 2011 of $342,418, the levelized FCR factor for 2011 did not change from the FCR factor excluding upgrade costs. Therefore, the levelized FCR factor for January 2011 through December 2011 based on the traditional methodology, including costs associated with the Scherer Unit 4 steam turbine upgrade is 4.464¢ per kWh. Schedule EI, Page 60 of Appendix II shows the calculation of this twelve-month levelized FCR factor. Schedule E2, Pages 67 and 68 of Appendix II shows the monthly fuel factors for January 2011 through December 2011 and also the twelve-month levelized FCR factor for the period including the $342,418.

Q. **Has the Company developed levelized FCR factors for its Time of Use rates based on the traditional factor calculation methodology, including costs associated with the Scherer Unit 4 steam turbine upgrade?**

A. Yes. Schedule E1-D Page 1 of 2, located on Page 63 of Appendix II, provides a twelve-month levelized FCR factor of 5.085¢ per kWh on-peak and 4.179¢ per kWh off-peak for our Time of Use rate schedules based on the traditional factor calculation methodology, including costs associated with the Scherer Unit 4 steam turbine upgrade. The time of use rates for the Seasonal Demand Time of Use Rider (SDTR) are 5.242¢ (on-peak) and 4.215¢ (off-peak) and are provided on Schedule E-1D, Page 2 of 2, located on Page 64 of Appendix II.

FCR factors by rate group for the period January 2011 through December 2011 based on the traditional factor calculation methodology, including costs associated with the Scherer Unit 4 steam turbine upgrade are presented on Schedule E1-E, Page 1 of 2, located on Page 65 of Appendix II. FCR factors by rate group for the SDTR are provided on

Schedule E-1E, Page 2 of 2, located on Page 66 of Appendix II.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2010 CCR Estimated/Actual True-up amount that was filed on August 2, 2010 to reflect July 2010 actual data?

A. Yes. The 2010 CCR estimated/actual true-up amount has been revised to an under-recovery of $88,494,367, reflecting July 2010 actual data plus interest. This $88,494,367 under-recovery, plus the 2009 final true-up over-recovery of $20,891,498 results in a net under-recovery of $67,602,870 (see Pages 3 and 4 of Appendix III). This $67,602,870 net under-recovery is to be included for recovery in the CCR factor for the January 2011 through December 2011 period.

Q. Have you prepared a summary of the requested capacity payments for the projected period of January 2011 through December 2011?

A. Yes. Page 5 of Appendix III provides this summary. Total Recoverable Capacity Payments are $609,681,261 (line 15) and include payments of $188,421,452 to non-cogenerators (line1), payments of $272,104,074 to cogenerators (line 2), $1,613,943 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 3), $49,351,038 in Incremental Power Plant Security Costs (line 5) and $16,769,276 in Transmission of Electricity by Others (line 6). These amounts are partially offset by $5,246,711 of Return Requirements on SJRPP Suspension Payments (line 4) and by Transmission Revenues from Capacity Sales of $2,411,394 (line 7). The resulting amount is then increased by the net under-recovery for 2009 and 2010 of $67,602,870 (line 11) and the Nuclear Power Plant Cost Recovery Clause amount of $31,288,445 (line 12).

Q. What does line 14 - Nuclear Power Plant Cost Recovery (NPPCR) represent?

A. FPL has included in the calculation of its CCR Factors $31,288,445 as reflected in Exhibit WP-7 contained in the supplemental NPPCR testimony and exhibits of Winnie Powers filed on August 17, 2010. Per Order No. PSC-07-0240-FOF-EI, issued on March 20, 2007, the Commission adopted Rule 25-6.0423 to implement Section 366.93, Florida Statutes, which was enacted by the Florida Legislature in 2006. The Rule provides the mechanism to determine recoverable costs and provides for annual recovery of those costs through the CCR.

Q. Have you prepared a calculation of the allocation factors for demand and energy?

A. Yes. Page 6 of Appendix III provides this calculation. 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 class contributes to total kWh sales, as adjusted for losses.

Q. Have you prepared a calculation of the proposed 2011 CCR factors by rate class?

A. Yes. Page 7 of Appendix III presents this calculation.

Q. What effective date is the Company requesting for the new FCR and

CCR factors?

A. FPL is requesting that the FCR and CCR factors become effective with customer bills for January 2011 (cycle day 1) through December 2011 (cycle day 21). This will provide for 12 months of billing on the FCR and CCR factors for all our customers.

IMPLEMENTATION OF STIPULATION AND SETTLEMENT AGREEMENT FOR FCR AND CCR CLAUSES

Q. If approved by the Commission, how will the Stipulation and Settlement that was filed in Docket Nos. 080677-EI and 090130-EI on August 20, 2010 (the "Settlement Agreement") impact the FCR and CCR clauses?

A. The Settlement Agreement states that beginning with the first billing cycle on or after the date on which WCEC-3 enters commercial service, FPL shall be authorized to recover during the remainder of the calendar year the lesser of the projected WCEC-3 non-fuel revenue requirements for the balance of the calendar year and the projected WCEC-3 fuel savings for the balance of the calendar year, via FPL's CCR clause. The Settlement Agreement also provides that FPL shall simultaneously implement revised FCR factors that reflect the projected WCEC-3 fuel savings.

Q. When does FPL project WCEC-3 to enter commercial operation?

A. FPL projects WCEC-3 to enter commercial operation on approximately

June 1, 2011.

Q. What are the projected WCEC-3 jurisdictional non-fuel revenue requirements from June 1, 2011 through the balance of 2011?

A. As explained in the testimony of FPL witness Ousdahl, the jurisdictional non-fuel revenue requirements for June 1, 2011 through December 31, 2011 are projected to be $99,629,081. As contemplated by the Settlement Agreement, this calculation reflects the projected Plant in Service balance and operating expenses for WCEC-3 that were used in the determination of need for the unit in Docket No. 080203-EI, with the 10% return on equity (ROE) approved by the Commission in Order No. PSC-10-0153-FOF-EI substituted for higher ROE that was used for the need determination.

Q. What are the projected WCEC-3 jurisdictional fuel savings from June 1, 2011 through the balance of 2011?

A. As explained in the testimony of FPL witness Yupp, the projected total fuel savings for the period above is $98,411,000. In order to calculate the WCEC 3 fuel savings, FPL ran two separate production cost simulations, one without WCEC 3 and one with WCEC 3. A comparison of the total system fuel costs from the production model for the two simulations showed that the fuel costs were $98,411,000 lower in the case that included WCEC 3 than in the case without WCEC 3. The jurisdictional portion of those fuel savings is $97,277,315. The calculation of this amount is shown on Schedule E1, in both Appendices IV and V.

Q. How does FPL propose to revise the 2011 CCR factors to reflect

recovery of WCEC-3 costs consistent with the Settlement Agreement?

A. As I explained earlier, the Settlement Agreement provides for FPL to recover the lesser of the non-fuel revenue requirements or the fuel savings associated with WCEC-3 for the portion of 2011 after it goes into service. Based on the information provided by Ms. Ousdahl and Mr. Yupp, the WCEC-3 fuel savings are less than its non-fuel revenue requirements for that period. Therefore, I have developed WCEC-3 Recovery Components that are designed to recover $97,277,315 in projected jurisdictional fuel savings from FPL's retail customers, based on the assumed in-service date of June 1, 2011. The $97,277,315 was allocated to customer classes utilizing the same cost of service and rate design methodology that was approved in FPL's recent rate case, Docket No. 080677-EI.

Page 12 of Appendix III provides the calculation of the WCEC-3 CCR components by rate class based on these revenue requirements. Pages 13-14 of Appendix III provide the total CCR factors, including the WCEC-3 CCR components that would apply during the period from when WCEC-3 goes into service through December 31, 2011.

Q. **How has FPL calculated the 2011 FCR factors to address the provision of the Settlement Agreement for WCEC-3 fuel savings to be reflected in the FCR factors commencing with the unit's in-service date?**

A. Per the methodology provided in the Settlement Agreement, FPL proposes to revise the 2011 fuel factor to include the fuel savings associated with its WCEC-3 beginning with the commercial operation date of WCEC-3, which is projected to be June 1, 2011.

To calculate the 2011 fuel factors per the Settlement Agreement, FPL has prepared two E-1 Schedules to calculate average "Step 1" fuel factors to be applied during the period before WCEC-3 goes into service (assumed to be January 2011 through May 2011) (Page 2 of Appendix IV) and separate average "Step 2" fuel factors to be applied during the period after WCEC-3 goes into service (assumed to be June 2011 through December 2011) (Page 9 of Appendix IV). FPL first calculates the Step 1 fuel factors assuming WCEC-3 is not operating in 2011, meaning that the total jurisdictional fuel savings are excluded from the calculation of the levelized fuel factor on both E-1 Schedules. This adjustment is shown on Line 1a.

Next, FPL adjusts the Step 2 fuel factors for the period June 2011 through December 2011 by crediting the fuel savings associated with WCEC-3 during this period. The total jurisdictional fuel savings of $97,277,315, divided by the projected sales for June 2011 through December 2011 of 63,929,494 mWh results in a downward adjustment of 0.1523 cents per kWh (including revenue taxes) (Schedule E-1, Line 33a, Page 9 of Appendix IV). This downward adjustments results in a lower levelized FCR factor of 4.407 cents per kWh. This represents $40.62 on a

Residential 1,000 kWh bill, which is $1.52 less than the $42.14 charge in January 2011.

Q. Has FPL also calculated the Step 1 and Step 2 FCR factors, including the costs associated with the Scherer Unit 4 Steam Turbine Upgrade?

A. Yes. FCR factors for the period January 2011 through December 2011 including the costs associated with the Scherer Unit 4 steam turbine upgrade are included in Appendix V of my testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KIM OUSDAHL

DOCKET NO. 100001-EI

September 1, 2010

Q. Please state your name and address.

A. My name is Kim Ousdahl, and my business address is Florida Power & Light 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" or the "Company") as Vice President, Controller and Chief Accounting Officer.

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

A. I am responsible for financial accounting and internal reporting for FPL, along with the management of the Property Accounting and Regulatory Accounting functions. In these roles, I am responsible for ensuring that the Company's financial reporting complies with the requirements of Generally Accepted Accounting Principles (GAAP) and multi-jurisdictional regulatory accounting requirements.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in Docket No. 080677-EI, the Company's 2009 base rate case, and Docket No. 080009-EI, the 2008 nuclear cost recovery proceeding.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the calculation of the revenue requirement of the West County Energy Center Unit 3 (WCEC 3). Specifically, this includes the calculation of the revenue requirement for WCEC 3 for the period June, 2011 through December, 2011, the first seven months of operation of this facility.

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

A. Yes, I have. They are as follows:

- KO-1 -- Determination of the Revenue Requirement for the West County Unit 3 (WCEC 3) Power Station
- KO-2 -- Capital Structure Calculation and Support for the Revenue Requirement of the WCEC 3 Power Station

Q. What is the purpose of the calculation of WCEC 3 revenue requirement as it relates to this proceeding?

A. FPL and the major intervenors in FPL's 2009 base rate proceeding have entered into a Stipulation and Settlement (the

"Settlement Agreement"), which was filed for Commission approval on August 20, 2010. The Settlement Agreement provides an opportunity for FPL to recover the previously approved revenue requirements for WCEC 3 through the capacity cost recovery clause starting with the first billing cycle after the unit goes into commercial service, limited to the amount of its projected fuel savings for that period of operation. While the Commission is not scheduled to rule on the Settlement Agreement until September 28, 2010, the Settlement Agreement contemplates that FPL will file for recovery of the WCEC 3 revenue requirement as part of its 2011 fuel cost recovery projection filing. I am providing a calculation of the 2011 WCEC 3 revenue requirement in support of FPL's recovery request. This request is contingent upon Commission approval of the Settlement Agreement.

Q. Please describe how the Revenue Requirement calculation was developed?

A. The development of the revenue requirement is based on the approach and assumptions utilized in the calculation of WCEC 3 revenue requirement in the need determination proceeding for that unit in Docket No. 080203-EI. The first step in the calculation of the revenue requirement was to calculate the jurisdictional average rate base represented by WCEC 3. As shown on KO-2 line 20, the beginning net plant balance as of June 2011 and the ending plant balance as of December 2011 on line 20, divided by two results in an average rate base of $861,859,229 (KO-2, line 24). The average rate base was then multiplied by the jurisdictional factor of 0.981404 (KO-2, line 25) which produces the jurisdictional average rate base of $845,832,095 (KO-2, line 26).

Next, FPL determined the required jurisdictional net operating income. This calculation was developed utilizing the jurisdictional average rate base (KO-1, line 1) multiplied by the weighted cost of capital (KO-1, line 3). As required in the Settlement Agreement, the weighted cost of capital has been adjusted to reflect a 10% ROE midpoint return on equity in lieu of the return on equity that was used in the need determination proceeding. This results in a required jurisdictional net operating income of $71,236,487 (KO-1, line 5). Because WCEC 3 is expected to go in service June 1, 2011, I calculated a partial year net operating income (KO-1, line 7). The $41,554,617 represents 7/12th of a full year of jurisdictional net operating income. The jurisdictional adjusted net operating loss of $19,413,788 (KO-1, line 9) represents operation and maintenance expenses, depreciation and taxes. The amount shown on KO-2, line 50 represents the jurisdictional net operating loss from June 2011 through December 2011.

Finally, the net operating income deficiency was determined (KO-1, line 7 minus KO-1, line 9), to arrive at a net operating income deficiency of $60,968,406 (KO-1, line 11). This amount was then grossed up for taxes, regulatory assessment fees and bad debt expense using the net operating income multiplier of 1.63411 (KO-1, line 13). The result is a jurisdictional revenue requirement in the amount of $99,629,081 (KO-1, line 15) for the seven months of 2011 during which the unit is projected to be in service.

Q. **What was the basis for the determination of the jurisdictional average rate base, capital ratios, operating expenses and jurisdictional operating income?**

A. All of the calculations shown on my exhibits KO-1 and KO-2 were developed using the need determination supporting data as filed in Docket No 080203-EI. The only exceptions are that FPL has used the 10% cost of common equity and the net operating income multiplier approved by the Commission in Docket No 080677-EI, Order No PSC-10-0153-FOF-EI.

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

A. Yes, it does.

APPENDIX I

FUEL COST RECOVERY

EXHIBIT GJY-4

DOCKET NO. 100001-EI

PAGES 1-4

SEPTEMBER 1, 2010

APPENDIX I

FUEL COST RECOVERY

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Florida Power and Light Company
Projected Dispatch Costs and Projected Availability of Natural Gas
January Through December 2011

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
1.0% Sulfur Grade ($/Bbl)	79.93	80.26	80.60	81.38	81.00	82.16	82.60	82.99	83.32	83.65	83.51	83.87
1.0% Sulfur Grade ($/mmBtu)	12.49	12.54	12.59	12.72	12.66	12.84	12.91	12.97	13.02	13.07	13.05	13.11

Light Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.05% Sulfur Grade ($/Bbl)	100.46	101.27	101.64	101.49	101.42	101.48	102.00	102.58	103.35	104.16	104.90	105.59
0.05% Sulfur Grade ($/mmBtu)	17.23	17.37	17.43	17.41	17.40	17.41	17.50	17.59	17.73	17.87	17.99	18.11

Natural Gas Transportation	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT (mmBtu/Day)	775,000	775,000	800,000	1,239,000	1,274,000	1,274,000	1,274,000	1,274,000	1,274,000	1,239,000	1,150,000	1,150,000
Firm Gulfstream (mmBtu/Day)	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000
Non-Firm FGT (mmBtu/Day)	100,000	100,000	100,000	185,000	160,000	115,000	115,000	115,000	115,000	160,000	185,000	185,000
Non-Firm Gulfstream (mmBtu/Day)	50,000	50,000	50,000	50,000	50,000	-	-	-	-	50,000	50,000	50,000
Total Projected Daily Availability (mmBtu/Day)	1,620,000	1,620,000	1,645,000	2,169,000	2,179,000	2,084,000	2,084,000	2,084,000	2,084,000	2,144,000	2,080,000	2,080,000
Southeast Supply Header (SESH)**	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Transcontinental Pipe Line (Transco)**	-	-	-	-	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000

**Note: The SESH and Transco firm transportation does not provide increased capacity to FPL's plants but does increase FPL's access to on-shore supply.

Natural Gas Dispatch Price	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT ($/mmBtu)	5.54	5.51	5.41	5.27	5.29	5.33	5.38	5.43	5.46	5.53	5.69	5.94
Firm Gulfstream ($/mmBtu)	5.50	5.47	5.36	5.22	5.25	5.28	5.34	5.38	5.41	5.48	5.64	5.89
Non-Firm FGT ($/mmBtu)	5.83	5.80	5.69	5.60	5.77	5.93	5.98	6.03	5.94	5.86	5.97	6.23
Non-Firm Gulfstream ($/mmBtu)	6.09	6.06	5.96	5.82	5.84	5.88	5.93	5.98	6.00	6.08	6.24	6.48

Coal	January	February	March	April	May	June	July	August	September	October	November	December
Scherer ($/mmBtu)	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19
SJRPP ($/mmBtu)	2.68	2.68	2.68	2.68	2.68	2.68	2.68	2.68	2.68	2.68	2.68	2.68

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2011

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral 1 (1)	0.0	0.0	0.0	NONE			
Cape Canaveral 2 (1)	0.0	0.0	0.0	NONE			
Cutler 5	0.0	0.0	0.0	NONE			
Cutler 6	0.0	0.0	0.0	NONE			
Lauderdale 4	0.4	1.3	9.6	03/12/11 - 04/15/11			
Lauderdale 5	0.3	2.0	0.0	NONE			
Lauderdale GTs	1.0	7.2	0.0	NONE			
Fort Myers 2 CC	0.5	4.5	9.4	04/02/11 - 06/10/11 *	04/02/11 - 04/15/11 *	04/16/11 - 04/29/11 *	05/28/11 - 06/10/11 *
Ft. Myers 3	3.0	3.2	3.8	07/13/11 - 07/19/11 *	07/20/11 - 07/26/11 *		
Ft. Myers GTs	0.3	1.3	1.0	05/01/11 - 06/24/11 *			
Manatee 1	0.2	4.1	6.3	02/19/11 - 03/13/11			
Manatee 2	0.2	3.6	11.5	03/14/11 - 03/23/11	11/07/11 - 12/08/11		
Manatee 3	0.6	3.1	10.0	01/08/11 - 02/02/11 *	02/03/11 - 02/23/11	02/03/11 - 02/28/11 *	
Martin 1	0.4	3.9	11.0	04/11/11 - 04/20/11	10/08/11 - 11/06/11		
Martin 2	0.4	4.3	10.1	03/05/11 - 04/10/11			
Martin 3	0.4	3.1	9.6	09/03/11 - 10/07/11			
Martin 4	0.4	4.0	9.6	05/14/11 - 06/17/11			
Martin 8 CC	0.7	4.0	11.1	04/23/11 - 05/13/11	10/29/11 - 11/23/11 *	11/26/11 - 12/21/11 *	
Port Everglades 1	0.0	0.0	0.0	NONE			
Port Everglades 2	0.0	0.0	0.0	NONE			
Port Everglades 3	0.0	0.0	0.0	NONE			
Port Everglades 4	0.0	0.0	0.0	NONE			
Port Everglades GTs	1.9	9.7	0.0	NONE			
Putnam 1	0.4	6.4	1.0	03/01/11 - 03/07/11 *			
Putnam 2	0.3	2.4	18.2	03/01/11 - 03/07/11 *	10/15/11 - 12/16/11		
Riviera 3 (1)	0.0	0.0	0.0	NONE			
Riviera 4 (1)	0.0	0.0	0.0	NONE			
Sanford 3	0.0	0.0	0.0	NONE			
Sanford 4 CC	0.7	2.5	1.9	02/19/11 - 02/25/11 *	02/26/11 - 03/04/11 *	03/05/11 - 03/11/11 *	03/12/11 - 03/18/11 *
Sanford 5 CC	0.4	3.3	1.9	06/11/11 - 06/17/11 *	06/18/11 - 06/24/11 *	06/25/11 - 07/01/11 *	08/27/11 - 09/02/11 *
Turkey Point 1	0.4	6.2	6.3	04/02/11 - 04/24/11			
Turkey Point 2	0.0	10.7	0.0	NONE			
Turkey Point 3	1.2	1.2	0.0	NONE			
Turkey Point 4	1.1	1.1	15.1	03/19/11 - 05/13/11			
Turkey Point 5	0.7	2.5	4.0	03/05/11 - 03/11/11 *	03/25/11 - 04/07/11 *	07/01/11 - 07/10/11 *	11/28/11 - 12/04/11
St. Lucie 1	0.9	0.9	30.1	08/29/11 - 12/17/11			
St. Lucie 2	1.0	1.0	22.5	01/03/11 - 03/26/11			
Saint Johns River Power Park 1	1.2	2.7	8.5	02/26/11 - 03/28/11			
Saint Johns River Power Park 2	1.3	1.5	0.0	NONE			
Scherer 4	1.2	2.8	10.1	06/07/11 - 07/13/11			
West County 1	1.4	8.1	5.5	09/17/11 - 10/06/11 *	10/07/11 - 10/26/11 *		
West County 2	1.6	3.7	4.1	02/12/11 - 02/26/11 *	02/27/11 - 03/13/11 *		
West County 3	0.9	1.9	0.0	NONE			

* Partial Planned Outage

(1) Unit unavailable due to modernization construction

APPENDIX II
FUEL COST RECOVERY
2011 E-SCHEDULES

BASED ON TRADITIONAL METHODOLOGY
EXCLUDING AND INCLUDING SCHERER UNIT 4 STEAM TURBINE UPGRADE

TJK-5
DOCKET NO. 100001-EI
FPL WITNESS: T.J. KEITH
EXHIBIT ______________
PAGES 1-70
SEPTEMBER 1, 2010

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES
January 2011 – December 2011
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APPENDIX II
BASED ON TRADITIONAL METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2011 -DECEMBER 2011

		(a) DOLLARS	(b) MWH	(c) ¢/KWH
1	Fuel Cost of System Net Generation (E3)	$3,918,477,328	100,446,655	3.9011
2	Nuclear Fuel Disposal Costs (E2)	19,509,650	20,930,855	0.0932
3	Fuel Cost of Sales to FKEC / CKW (E2)	(45,215,546)	(974,289)	4.6409
4	TOTAL COST OF GENERATED POWER	$3,892,771,432	99,472,367	3.9134
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	222,436,193	6,404,103	3.4733
6	Energy Cost of Economy Purchases (Florida) (E9)	47,620,744	775,570	6.1401
7	Energy Cost of Economy Purchases (Non-Florida) (E9)	32,097,565	625,025	5.1354
8	Payments to Qualifying Facilities (E8)	153,332,683	4,073,261	3.7644
9	TOTAL COST OF PURCHASED POWER	$455,487,185	11,877,959	3.8347
10	TOTAL AVAILABLE KWH (LINE 6 + LINE 11)		111,350,326	
11	Fuel Cost of Economy Sales (E6)	(40,232,035)	(873,500)	4.6058
12	Gain on Economy Sales (E6)	(9,692,706)	(1,252,119)	0.7741
13	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(2,446,761)	(378,619)	0.6462
14	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
15	TOTAL FUEL COST AND GAINS OF POWER SALES	($52,371,501)	(1,252,119)	4.1826
16	Net Inadvertent Interchange	0	0	
17	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 6 + 11 + 18)	$4,295,887,115	110,098,206	3.9019
18	Net Unbilled Sales	(25,332,817) **	(649,248)	(0.0245)
19	Company Use	12,887,661 **	330,295	0.0125
20	T & D Losses	279,232,662 **	7,156,383	0.2704
21	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$4,295,887,115	103,260,777	4.1602
22	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$49,488,190	1,189,558	4.1602
23	Jurisdictional MWH Sales	$4,246,398,925	102,071,219	4.1602
24	Jurisdictional Loss Multiplier	-	-	1.00083
25	Jurisdictional MWH Sales Adjusted for Line Losses	$4,249,923,436	102,071,219	4.1637
26	FINAL TRUE-UP Jan 09- Dec 09 $8,771,414 underrecovery; EST/ACT TRUE-UP Jan 10 - Dec 10 $286,129,908 underrecovery	294,901,322	102,071,219	0.2889
27	TOTAL JURISDICTIONAL FUEL COST	$4,544,824,758	102,071,219	4.4526
28	Revenue Tax Factor			1.00072
29	Fuel Factor Adjusted for Taxes	4,548,097,032		4.4558
30	GPIF ***	$8,115,900	102,071,219	0.0080
31	Fuel Factor Including GPIF (Line 32 + Line 33)	4,556,212,932	102,071,219	4.4638
32	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			4.464

** 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: JANUARY 2011 - DECEMBER 2011

1. Estimated/Actual over/(under) recovery (January 2010 - December 2010)		$ (286,129,908)
2. Final over/(under) recovery (January 2009 - December 2009)	$ (8,771,414)	
3. Total over/(under) recovery to be included in the January 2011 - December 2011 projected period (Schedule E1, Line 26)		$ (294,901,322)
4. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)		102,071,219
5. True-Up Factor (Lines 3/4) c/kWh:		(0.2889)

REVISED

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2010

LINE NO.			(1) ACTUAL JAN	(2) ACTUAL FEB	(3) ACTUAL MAR	(4) ACTUAL APR	(5) ACTUAL MAY	(6) ACTUAL JUN
A		**Fuel Costs & Net Power Transactions**						
1	a	Fuel Cost of System Net Generation	$ 378,533,784	$ 247,792,496	$ 258,792,333	$ 276,339,803	$ 372,679,512	$ 435,222,107
	b	Incremental Hedging Costs	$ 51,225	$ 36,065	$ -	$ -	$ -	$ -
	c	Nuclear Fuel Disposal Costs	$ 2,043,474	$ 1,905,348	$ 2,090,331	$ 1,460,650	$ 1,442,608	$ 1,471,860
	d	Scherer Coal Cars Depreciation & Return	$ 74,704	$ 74,034	$ 73,236	$ 72,657	$ (5,773)	$ -
	e	DOE D&D Fund Payment	$ -	$ -	$ -	$ -	$ -	$ -
2	a	Fuel Cost of Power Sold (Per A6)	$ (2,785,805)	$ (3,439,331)	$ (2,104,182)	$ (487,993)	$ (317,396)	$ (1,043,999)
	b	Gains from Off-System Sales	$ (700,142)	$ (1,045,544)	$ (637,729)	$ (161,575)	$ (47,295)	$ (11,282)
3	a	Fuel Cost of Purchased Power (Per A7)	$ 21,519,902	$ 26,977,144	$ 17,505,531	$ 20,334,815	$ 24,960,809	$ 32,878,864
	b	Energy Payments to Qualifying Facilities (Per A8)	$ 13,569,500	$ 12,180,154	$ 10,084,009	$ 7,226,308	$ 12,712,002	$ 23,060,407
4		Energy Cost of Economy Purchases (Per A9)	$ 2,128,949	$ 372,716	$ 50,667	$ 1,094,138	$ 20,692,467	$ 35,873,446
5		Total Fuel Costs & Net Power Transactions	$ 414,435,591	$ 284,853,082	$ 285,854,194	$ 305,878,804	$ 432,116,934	$ 527,451,402
6		**Adjustments to Fuel Cost**						
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (3,530,116)	$ (4,211,769)	$ (3,076,009)	$ (3,228,478)	$ (3,164,529)	$ (4,369,021)
	b	Energy Imbalance Fuel Revenues	$ (76,823)	$ (351,680)	$ (79,847)	$ (91,728)	$ 106,367	$ (314,065)
	c	Inventory Adjustments	$ (69,559)	$ 147,744	$ (95,104)	$ (368,276)	$ 113,300	$ (49,285)
	d	Non Recoverable Oil/Tank Bottoms - Docket No. 13092	$ (402,574)	$ -	$ (24,110)	$ -	$ 293,850	$ -
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 410,356,519	$ 280,437,377	$ 282,579,125	$ 302,190,323	$ 429,465,922	$ 522,719,031
B		**kWh Sales**						
1		Jurisdictional kWh Sales	$ 9,116,973,254	$ 7,491,191,418	$ 7,202,475,549	$ 6,885,209,812	$ 8,296,041,541	$ 9,976,346,291
2		Sale for Resale (excluding FKEC & CKW)	$ 5,380,147	$ 109,830,597	$ 86,226,967	$ 89,234,836	$ 87,254,389	$ 111,812,226
3		Sub-Total Sales (excluding FKEC & CKW)	$ 9,122,353,401	$ 7,601,022,015	$ 7,288,702,516	$ 6,974,444,648	$ 8,383,295,930	$ 10,088,158,517
4		**Jurisdictional % of Total Sales (B1/B3)**	0.9994102	0.9855505	0.9881698	0.9872055	0.9895919	0.9889165
C		**True-up Calculation**						
1		Juris Fuel Revenues (Net of Revenue Taxes)	$ (18,393,991)	$ 308,542,108	$ 297,757,817	$ 282,918,400	$ 345,371,019	$ 420,620,978
2		**Fuel Adjustment Revenues Not Applicable to Period**						
	a	Prior Period True-up (Collected)/Refunded This Period (b)	$ 364,843,209		$ -	$ -	$ -	$ -
	b	GPIF, Net of Revenue Taxes (a)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)
3		Jurisdictional Fuel Revenues Applicable to Period	$ 345,494,544	$ 307,587,434	$ 296,803,143	$ 281,963,726	$ 344,416,345	$ 419,666,304
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 410,356,519	$ 280,437,377	$ 282,579,125	$ 302,190,323	$ 429,465,922	$ 522,719,031
	b	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	$ 410,356,519	$ 280,437,377	$ 282,579,125	$ 302,190,323	$ 429,465,922	$ 522,719,031
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	0.9994102	0.9855505	0.9881698	0.9872055	0.9895919	0.9889165
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00040) +(Lines C4b,c,d)	$ 410,278,537	$ 276,495,751	$ 279,347,852	$ 298,443,278	$ 425,165,996	$ 517,132,245
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (64,783,993)	$ 31,091,683	$ 17,455,291	$ (16,479,552)	$ (80,749,651)	$ (97,465,941)
8		Interest Provision for the Month (Line D10)	$ 23,548	$ (9,904)	$ (5,901)	$ (6,093)	$ (19,442)	$ (49,159)
9	a	True-up & Interest Provision Beg. of Period -	$ 364,843,209	$ (64,760,445)	$ (33,678,667)	$ (16,229,277)	$ (32,714,921)	$ (113,484,014)
	b	Deferred True-up Beginning of Period - Over/(Under) Recovery	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)
10	a	Prior Period True-up Collected/(Refunded) This Period	$ (364,843,209)	$ -	$ -	$ -	$ -	$ -
	b	Prior Period True-up Collected/(Refunded) This Period						
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (73,531,859)	$ (42,450,081)	$ (25,000,691)	$ (41,486,335)	$ (122,255,428)	$ (219,770,528)

NOTES

(a) Generation Performance Incentive Factor is (($11,464,340) x 99.9280%) - See Order No. PSC-09-0795-FOF-EI.

(b) Refund of 364.8 million net true-up under-recovery per Order No. PSC-09-0795-FOF-EI

REVISED

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2010

	LINE NO.			(7) ACTUAL JUL	(8) ESTIMATED AUG	(9) ESTIMATED SEP	(10) ESTIMATED OCT	(11) ESTIMATED NOV	(12) ESTIMATED DEC	(13) TOTAL PERIOD
A			**Fuel Costs & Net Power Transactions**							
	1	a	Fuel Cost of System Net Generation	$ 429,694,589	$ 418,623,712	$ 379,462,859	$ 387,036,394	$ 266,233,290	$ 261,768,044	$ 4,112,178,923
		b	Incremental Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 87,290
		c	Nuclear Fuel Disposal Costs	$ 1,876,990	$ 1,987,193	$ 1,862,629	$ 1,518,620	$ 1,908,888	$ 2,037,156	$ 21,605,747
		d	Scherer Coal Cars Depreciation & Return	$ -	$ -	$ -	$ -	$ -	$ -	$ 288,857
		e	DOE D&D Fund Payment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	2	a	Fuel Cost of Power Sold (Per A6)	$ (1,280,431)	$ (2,828,993)	$ (1,451,061)	$ (2,635,253)	$ (3,214,888)	$ (5,204,689)	$ (26,794,022)
		b	Gains from Off-System Sales	$ (33,246)	$ (474,747)	$ (167,047)	$ (329,985)	$ (960,299)	$ (1,714,472)	$ (6,283,363)
	3	a	Fuel Cost of Purchased Power (Per A7)	$ 32,492,319	$ 22,841,162	$ 23,007,338	$ 23,920,719	$ 14,688,751	$ 15,664,050	$ 276,791,404
		b	Energy Payments to Qualifying Facilities (Per A8)	$ 20,065,626	$ 20,058,000	$ 19,155,000	$ 16,197,000	$ 11,527,000	$ 16,006,000	$ 181,841,005
	4		Energy Cost of Economy Purchases (Per A9)	$ 31,653,691	$ 9,924,000	$ 8,313,800	$ 5,933,500	$ 1,548,000	$ 1,202,400	$ 118,787,775
	5		Total Fuel Costs & Net Power Transactions	$ 514,469,538	$ 470,130,327	$ 430,183,518	$ 431,640,995	$ 291,730,741	$ 289,758,489	$ 4,678,503,616
	6		**Adjustments to Fuel Cost**							
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West	$ (4,843,895)	$ (4,773,166)	$ (4,836,284)	$ (4,689,155)	$ (4,331,485)	$ (3,880,453)	$ (48,934,359)
		b	Energy Imbalance Fuel Revenues	$ (21,221)	$ -	$ -	$ -	$ -	$ -	$ (828,996)
		c	Inventory Adjustments	$ 31,617	$ -	$ -	$ -	$ -	$ -	$ (289,563)
		d	Non Recoverable Oil/Tank Bottoms - Docket No. 13092	$ 8,114	$ -	$ -	$ -	$ -	$ -	$ (124,721)
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 509,644,153	$ 465,357,161	$ 425,347,234	$ 426,951,841	$ 287,399,256	$ 285,878,036	$ 4,628,325,977
B			**kWh Sales**							
	1		Jurisdictional kWh Sales	$ 10,473,503,945	$ 9,745,715,135	$ 10,218,618,336	$ 8,764,797,033	$ 8,105,627,877	$ 7,784,653,926	$ 104,061,154,117
	2		Sale for Resale (excluding FKEC & CKW)	$ 115,741,364	$ 116,500,427	$ 121,290,071	$ 110,614,743	$ 101,498,650	$ 82,788,090	$ 1,138,172,507
	3		Sub-Total Sales (excluding FKEC & CKW)	$ 10,589,245,309	$ 9,862,215,562	$ 10,339,908,406	$ 8,875,411,776	$ 8,207,126,527	$ 7,867,442,016	$ 105,199,326,623
	4		**Jurisdictional % of Total Sales (B1/B3)**	0.9890699	0.9881872	0.9882697	0.9875369	0.9876329	0.9894771	0.9891808
C			**True-up Calculation**							
	1		Juris Fuel Revenues (Net of Revenue Taxes)	$ 443,567,536	$ 406,493,264	$ 426,218,031	$ 365,579,221	$ 338,085,311	$ 324,697,504	$ 3,941,457,198
	2		**Fuel Adjustment Revenues Not Applicable to Period**							
		a	Prior Period True-up (Collected)/Refunded This Period (b)	$ -	$ -	$ -	$ -	$ -	$ -	$ 364,843,209
		b	GPIF, Net of Revenue Taxes (a)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)	$ (11,456,086)
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 442,612,863	$ 405,538,590	$ 425,263,357	$ 364,624,548	$ 337,130,637	$ 323,742,830	$ 4,294,844,321
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Lin	$ 509,644,153	$ 465,357,161	$ 425,347,234	$ 426,951,841	$ 287,399,256	$ 285,878,036	$ 4,628,325,977
		b	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	$ 509,644,153	$ 465,357,161	$ 425,347,234	$ 426,951,841	$ 287,399,256	$ 285,878,036	$ 4,628,325,977
	5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	0.9890699	0.9881872	0.9882697	0.9875369	0.9876329	0.9894771	0.9891808
	6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4c x C5 x 1.00040) +(Lines C4b,c,d)	$ 504,275,321	$ 460,043,934	$ 420,525,926	$ 421,799,349	$ 283,958,499	$ 282,982,918	$ 4,580,449,606
	7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (61,662,459)	$ (54,505,344)	$ 4,737,431	$ (57,174,802)	$ 53,172,138	$ 40,759,912	$ (285,605,285)
	8		Interest Provision for the Month (Line D10)	$ (65,783)	$ (72,032)	$ (77,854)	$ (83,989)	$ (84,475)	$ (73,538)	$ (524,623)
	9	a	True-up & Interest Provision Beg. of Period -	$ (210,999,114)	$ (272,727,356)	$ (327,304,732)	$ (322,645,154)	$ (379,903,945)	$ (326,816,282)	$ 364,843,209
		b	Deferred True-up Beginning of Period - Over/(Under) Rec	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)
	10	a	Prior Period True-up Collected/(Refunded) This Period	$ -	$ -	$ -	$ -	$ -	$ -	$ (364,843,209)
		b	Prior Period True-up Collected/(Refunded) This Period							$ -
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (281,498,770)	$ (336,076,146)	$ (331,416,568)	$ (388,675,359)	$ (335,587,696)	$ (294,901,322)	$ (294,901,322)

NOTES
(a) **Generation Performance Incentive Factor is (($11,464,340) x 99.9280%) - See Order No. PSC-09-0795-FOF-EI.**
(b) **Refund of 364.8 million net true-up under-recovery per Order No. PSC-09-0795-FOF-EI**

APPENDIX II

SCHEDULE E - 1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE - UP FACTOR FLORIDA POWER AND LIGHT COMPANY FOR THE PERIOD: JANUARY 2011 - DECEMBER 2011

1. TOTAL AMOUNT OF ADJUSTMENTS:	303,017,222
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$8,115,900
B. TRUE-UP (OVER)/UNDER RECOVERED	$ 294,901,322
2. TOTAL JURISDICTIONAL SALES (MWH)	102,071,219
3. ADJUSTMENT FACTORS c/kWh:	0.2969
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0080
B. TRUE-UP FACTOR	0.2889

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D
Page 1 of 2

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2011 - DECEMBER 2011

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	31.48	36.17
OFF PEAK	68.52	63.83
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$4,295,887,115	$1,553,822,243	$2,742,064,872
2	MWH SALES	103,260,777	32,508,973	70,751,804
3	COST PER KWH SOLD	4.1602	4.7797	3.8756
4	JURISDICTIONAL LOSS FACTOR	1.00083	1.00083	1.00083
5	JURISDICTIONAL FUEL FACTOR	4.1637	4.7836	3.8788
6	TRUE-UP	0.2889	0.2889	0.2889
7				
8	TOTAL	4.4526	5.0725	4.1677
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	4.4558	5.0762	4.1707
11	GPIF	0.0080	0.0080	0.0080
12	RECOVERY FACTOR including GPIF	4.4638	5.0842	4.1787
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.464	5.084	4.179

HOURS:	ON-PEAK	25.10 %
	OFF-PEAK	74.90 %

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR) FUEL RECOVERY FACTORS

ON PEAK: JUNE 2011 THROUGH SEPTEMBER 2011 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	24.30	28.83
OFF PEAK	75.70	71.17
	100.00	100.00

SDTR FUEL RECOVERY CALCULATION

	TOTAL	ON-PEAK	OFF-PEAK
1 TOTAL FUEL & NET POWER TRANS	$4,295,887,115	$1,238,584,302	$3,057,302,813
2 MWH SALES	103,260,777	25,089,710	78,171,067
3 COST PER KWH SOLD	4.1602	4.9366	3.9110
4 JURISDICTIONAL LOSS FACTOR	1.00083	1.00083	1.00083
5 JURISDICTIONAL FUEL FACTOR	4.1637	4.9407	3.9143
6 TRUE-UP	0.2889	0.2889	0.2889
7			
8 TOTAL	4.4526	5.2296	4.2032
9 REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10 SDTR RECOVERY FACTOR	4.4558	5.2334	4.2062
11 GPIF	0.0080	0.0080	0.0080
12 SDTR RECOVERY FACTOR including GPIF	4.4638	5.2414	4.2142
13 SDTR RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.464	5.241	4.214

HOURS:	ON-PEAK	19.67 %
	OFF-PEAK	80.33 %

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1D, Page 1 of 2.

FLORIDA POWER & LIGHT COMPANY

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

JANUARY 2011 - DECEMBER 2011

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh		4.464	1.00207	4.119
	all additional kWh		4.464	1.00207	5.119
A	GS-1, SL-2, GSCU-1, WIES-1		4.464	1.00207	4.473
A-1*	SL-1, OL-1, PL-1		4.324	1.00207	4.333
B	GSD-1		4.464	1.00202	4.473
C	GSLD-1 & CS-1		4.464	1.00116	4.469
D	GSLD-2, CS-2, OS-2 & MET		4.464	0.99426	4.438
E	GSLD-3 & CS-3		4.464	0.96229	4.295
A	RST-1, GST-1	ON-PEAK	5.084	1.00207	5.095
		OFF-PEAK	4.179	1.00207	4.187
B	GSDT-1, CILC-1(G),	ON-PEAK	5.084	1.00201	5.094
	HLFT-1 (21-499 kW)	OFF-PEAK	4.179	1.00201	4.187
C	GSLDT-1, CST-1,	ON-PEAK	5.084	1.00127	5.091
	HLFT-2 (500-1,999 kW)	OFF-PEAK	4.179	1.00127	4.184
D	GSLDT-2, CST-2,	ON-PEAK	5.084	0.99552	5.061
	HLFT-3 (2,000+ kW)	OFF-PEAI	4.179	0.99552	4.160
E	GSLDT-3,CST-3,	ON-PEAK	5.084	0.96229	4.892
	CILC -1(T)	OFF-PEAK	4.179	0.96229	4.021
	& ISST-1(T)				
F	CILC -1(D) &	ON-PEAK	5.084	0.99484	5.058
	ISST-1(D)	OFF-PEAK	4.179	0.99484	4.157

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

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2011 THROUGH SEPTEMBER 2011 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

(1) GROUP	(2) OTHERWISE APPLICABLE RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) SDTR FUEL RECOVERY FACTOR
B	GSD(T)-1	ON-PEAK	5.241	1.00202	5.252
		OFF-PEAK	4.214	1.00202	4.223
C	GSLD(T)-1	ON-PEAK	5.241	1.00123	5.248
		OFF-PEAK	4.214	1.00123	4.219
D	GSLD(T)-2	ON-PEAK	5.241	0.99599	5.220
		OFF-PEAK	4.214	0.99599	4.197

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

Florida Power & Light Company
2010 Actual Energy Losses by Rate Class

Line No	Rate Class	Voltage Level (Note 1)	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	RS-1	S	51,378,168	1.06671356	54,805,789	0.937459	3,427,621	1.00207
2								
3	CILC-1D	P	1,027,231	1.04404188	1,072,472	0.957816	45,241	
4	CILC-1D	S	1,999,113	1.06671356	2,132,481	0.937459	133,368	
5	CILC-1D Total		3,026,344	1.05901812	3,204,953	0.944271	178,609	0.99484
6								
7	CILC-1G	P	15	1.04404188	16	0.957816	1	
8	CILC-1G	S	195,776	1.06671356	208,837	0.937459	13,061	
9	CILC-1G Total		195,792	1.06671182	208,853	0.937460	13,062	1.00206
10								
11	CILC-1T	T	1,524,465	1.02436840	1,561,614	0.976211	37,149	0.96229
12								
13	CS-1	P	23,851	1.04404188	24,901	0.957816	1,050	
14	CS-1	S	161,291	1.06671356	172,051	0.937459	10,760	
15	CS-1 Total		185,142	1.06379286	196,952	0.940033	11,811	0.99932
16								
17	CS-2	P	29,127	1.04404188	30,410	0.957816	1,283	
18	CS-2	S	51,732	1.06671356	55,184	0.937459	3,451	
19	CS-2 Total		80,860	1.05854679	85,594	0.944691	4,734	0.99439
20								
21	CS-3	T	0	1.02436840	0	0.000000	0	0.00000
22								
23	GS-1	S	5,850,493	1.06671356	6,240,800	0.937459	390,307	1.00207
24								
25	GSCU-1	S	31,777	1.06671356	33,897	0.937459	2,120	1.00207
26								
27	GSD-1	P	54,081	1.04404188	56,462	0.957816	2,382	
28	GSD-1	S	22,784,033	1.06671356	24,304,037	0.937459	1,520,004	
29	GSD-1 Total		22,838,114	1.06665988	24,360,499	0.937506	1,522,386	1.00202
30								
31	GSLD-1	P	194,812	1.04404188	203,392	0.957816	8,580	
32	GSLD-1	S	4,788,225	1.06671356	5,107,665	0.937459	319,440	
33	GSLD-1 Total		4,983,037	1.06582721	5,311,057	0.938238	328,019	1.00123
34								
35	GSLD-2	P	230,160	1.04404188	240,296	0.957816	10,137	
36	GSLD-2	S	576,854	1.06671356	615,338	0.937459	38,484	
37	GSLD-2 Total		807,014	1.06024762	855,635	0.943176	48,621	0.99599
38								
39	GSLD-3	T	237,106	1.02436840	242,883	0.976211	5,778	0.96229
40								
41	HLFT-1	P	14,071	1.04404188	14,691	0.957816	620	
42	HLFT-1	S	1,374,873	1.06671356	1,466,596	0.937459	91,723	
43	HLFT-1 Total		1,388,944	1.06648388	1,481,287	0.937661	92,342	1.00185
44								
45	HLFT-2	P	171,853	1.04404188	179,422	0.957816	7,569	
46	HLFT-2	S	5,150,169	1.06671356	5,493,755	0.937459	343,586	
47	HLFT-2 Total		5,322,023	1.06598147	5,673,178	0.938103	351,155	1.00138

Florida Power & Light Company
2010 Actual Energy Losses by Rate Class

Line No	Rate Class	Voltage Level (Note 1)	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
48								
49	HLFT-3	P	360,256	1.04404188	376,122	0.957816	15,866	
50	HLFT-3	S	767,541	1.06671356	818,747	0.937459	51,205	
51	HLFT-3 Total		1,127,797	1.05947148	1,194,869	0.943867	67,072	0.99526
52								
53	MET	P	91,351	1.04404188	95,375	0.957816	4,023	0.98077
54								
55	OL-1	S	102,787	1.06671356	109,645	0.937459	6,857	1.00207
56								
57	OS-2	P	13,105	1.04404188	13,682	0.957816	577	
58	OS-2	S	-	1.06671356	-	0.000000	-	
59	OS-2 Total		13,105	1.04404188	13,682	0.957816	577	0.98077
60								
61	STDR-1	P	632	1.04404188	660	0.957816	28	
62	STDR-1	S	477,386	1.06671356	509,234	0.937459	31,848	
63	STDR-1 Total		478,018	1.06668359	509,894	0.937485	31,876	1.00204
64								
65	STDR-2	P	83,453	1.04404188	87,128	0.957816	3,675	
66	STDR-2	S	495,461	1.06671356	528,515	0.937459	33,054	
67	STDR-2 Total		578,914	1.06344535	615,643	0.940340	36,729	0.99900
68								
69	STDR-3	P	28,069	1.04404188	29,305	0.957816	1,236	
70	STDR-3	S	41,010	1.06671356	43,746	0.937459	2,736	
71	STDR-3 Total		69,079	1.05750126	73,051	0.945625	3,972	0.99341
72								
73	SL-1	S	518,383	1.06671356	552,966	0.937459	34,583	1.00207
74								
75	SL-2	S	30,485	1.06671356	32,519	0.937459	2,034	1.00207
76								
77	SST-1D	P	7,231	1.04404188	7,550	0.957816	318	
78	SST-1D	S	0	1.06671356	0	0.000000	0	
79	SST-1D Total		7,231	1.04404188	7,550	0.957816	318	0.98077
80								
81	SST-1T	T	129,128	1.02436840	132,275	0.976211	3,147	0.96229
82								
83	**Rate Class Groups -**							
84								
85	CILC-1D / CILC-1G		3,222,135	1.05948563	3,413,806	0.943854	191,671	0.99528
86								
87	GSDT-1 / HLFT-1		24,227,058	1.06664979	25,841,786	0.937515	1,614,728	1.00201
88								
89	GSDT-1, CILC-1G & HLFT-1		24,422,849	1.06665028	26,050,639	0.937514	1,627,790	1.00201
90								
91	GSLD-1 / CS-1		5,168,179	1.06575434	5,508,009	0.938303	339,830	1.00116
92								
93	GSLDT-1, CST-1 & HLFT-2		10,490,201	1.06586957	11,181,186	0.938201	690,985	1.00127
94								
95	GSLD-2 / CS-2		887,873	1.06009273	941,228	0.943314	53,355	0.99585
96								
97	GSLDT-2, CST-2 & HLFT-3		2,015,670	1.05974513	2,136,097	0.943623	120,426	0.99552

Florida Power & Light Company
2010 Actual Energy Losses by Rate Class

Line No	Rate Class	Voltage Level (Note 1)	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
98								
99	GSLD-2, CS-2, OS-2 & MET		992,330	1.05840316	1,050,285	0.944820	57,955	0.99426
100								
101	GSLD-3 / CS-3		237,106	1.02436840	242,883	0.976211	5,778	0.96229
102								
103	GSLDT-3, CST-3 & CILC-1T		1,761,571	1.02436840	1,804,497	0.976211	42,927	0.96229
104								
105	OL-1 / SL-1		621,171	1.06671356	662,611	0.937459	41,440	1.00207
106								
107	SL-2 / GSCU-1		62,262	1.06671356	66,415	0.937459	4,154	1.00207
108								
109	Total FPSC		100,995,555	1.06539795	107,600,457	0.938616	6,604,902	1.00083
110								
111	Total FERC Sales		2,228,500	1.02436840	2,282,804	0.976211	54,305	
112								
113	Total Company		103,224,055	1.06451217	109,883,262	0.939397	6,659,207	
114								
115	Company Use		121,228	1.06671356	129,315	0.937459	8,088	
116								
117	Total FPL		103,345,282	1.06451475	110,012,577	0.939395	6,667,295	1.00000
118								
119	**Summary of Sales by Voltage:**							
120								
121	Transmission		4,119,199	1.02436840	4,219,577	0.976211	100,378	
122								
123	Primary		2,329,298	1.04404188	2,431,884	0.957816	102,587	
124								
125	Secondary		96,775,558	1.06671356	103,231,801	0.937459	6,456,242	
126								
127	Total		103,224,055	1.06451217	109,883,262	0.939397	6,659,207	
128								
129								
130	**Note 1:**							
131	T = Transmission Voltage							
132	P = Primary Voltage							
133	S = Secondary Voltage							

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2011 - DECEMBER 2011

SCHEDULE E2

LINE NO.		(a) JANUARY ESTIMATED	(b) FEBRUARY ESTIMATED	(c) MARCH ESTIMATED	(d) APRIL ESTIMATED	(e) MAY ESTIMATED	(f) JUNE ESTIMATED	(g) 6 MONTH SUB-TOTAL	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$282,465,430	$246,439,168	$277,867,113	$298,019,007	$343,936,505	$348,794,790	$1,797,522,011	1
2	NUCLEAR FUEL DISPOSAL	1,578,003	1,396,693	1,438,035	1,469,633	1,805,809	1,923,091	9,611,264	2
3	FUEL COST OF POWER SOLD	(6,746,669)	(8,210,258)	(5,030,664)	(2,391,451)	(1,574,033)	(1,659,181)	(25,612,255)	3
4	GAIN ON ECONOMY SALES	(1,823,390)	(1,923,974)	(1,132,972)	(365,649)	(233,823)	(256,730)	(5,736,539)	4
5	FUEL COST OF PURCHASED POWER	17,001,688	15,507,270	12,095,521	20,064,019	22,693,723	20,603,441	107,965,664	5
6	QUALIFYING FACILITIES	13,118,570	13,560,610	12,960,754	5,812,521	11,210,361	14,755,317	71,418,133	6
7	ENERGY COST OF ECONOMY PURCHASES	1,015,902	687,594	931,652	3,636,225	12,511,553	20,393,488	39,176,414	7
8	FUEL COST OF SALES TO FKEC / CKW	(3,215,041)	(3,149,627)	(3,244,019)	(3,571,096)	(3,862,515)	(4,190,308)	(21,232,605)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$303,394,494	$264,307,477	$295,885,422	$322,673,209	$386,487,579	$400,363,907	$1,973,112,087	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,264,331	7,246,664	7,396,703	7,356,403	8,317,721	9,362,714	47,944,537	10
11	COST PER KWH SOLD (¢/KWH)	3.6711	3.6473	4.0002	4.3863	4.6466	4.2762	4.1154	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	3.6742	3.6503	4.0036	4.3899	4.6504	4.2797	4.1188	13
14	TRUE-UP (¢/KWH)	0.3005	0.3434	0.3360	0.3382	0.2987	0.2655	0.3111	14
15	TOTAL	3.9747	3.9937	4.3396	4.7281	4.9491	4.5452	4.4299	15
16	REVENUE TAX FACTOR 0.00072	0.0029	0.0029	0.0031	0.0034	0.0036	0.0033	0.0032	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	3.9776	3.9966	4.3427	4.7315	4.9527	4.5485	4.4331	17
18	GPIF (¢/KWH)	0.0083	0.0094	0.0092	0.0093	0.0082	0.0073	0.0086	18
19	RECOVERY FACTOR including GPIF	3.9859	4.0060	4.3519	4.7408	4.9609	4.5558	4.4417	19
20	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	3.986	4.006	4.352	4.741	4.961	4.556	4.442	20

APPENDIX II
BASED ON TRADITIONAL METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2011 - DECEMBER 2011

SCHEDULE E2

LINE NO.		(h) JULY ESTIMATED	(i) AUGUST ESTIMATED	(j) SEPTEMBER ESTIMATED	(k) OCTOBER ESTIMATED	(l) NOVEMBER ESTIMATED	(m) DECEMBER ESTIMATED	(n) 12 MONTH PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$387,813,785	$400,954,046	$395,820,616	$370,731,454	$288,661,681	$276,973,737	$3,918,477,328	1
2	NUCLEAR FUEL DISPOSAL	1,987,193	1,932,293	1,374,103	1,419,905	1,405,498	1,779,394	$19,509,650	2
3	FUEL COST OF POWER SOLD	(2,287,013)	(2,822,926)	(1,290,210)	(2,233,840)	(3,057,590)	(5,374,962)	($42,678,796)	3
4	GAIN ON ECONOMY SALES	(332,757)	(483,027)	(160,097)	(329,025)	(955,689)	(1,695,572)	($9,692,706)	4
5	FUEL COST OF PURCHASED POWER	21,970,282	21,391,572	22,938,069	21,986,795	13,094,526	13,089,284	$222,436,193	5
6	QUALIFYING FACILITIES	15,911,682	15,591,655	15,824,779	12,152,957	7,906,070	14,527,407	$153,332,683	6
7	ENERGY COST OF ECONOMY PURCHASES	10,897,788	10,646,300	10,006,799	6,336,300	1,516,220	1,138,489	$79,718,309	7
8	FUEL COST OF SALES TO FKEC / CKW	(4,331,369)	(4,458,628)	(4,385,071)	(3,969,481)	(3,589,740)	(3,248,653)	($45,215,546)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$431,629,590	$442,751,285	$440,128,987	$406,095,066	$304,980,976	$297,189,124	$4,295,887,115	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	9,972,647	9,903,541	10,377,478	8,910,784	8,245,065	7,906,722	103,260,777	10
11	COST PER KWH SOLD (¢/KWH)	4.3281	4.4706	4.2412	4.5573	3.6990	3.7587	4.1602	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	4.3317	4.4743	4.2447	4.5611	3.7020	3.7618	4.1637	13
14	TRUE-UP (¢/KWH)	0.2491	0.2511	0.2396	0.2793	0.3018	0.3141	0.2889	14
15	TOTAL	4.5808	4.7254	4.4843	4.8404	4.0038	4.0759	4.4526	15
16	REVENUE TAX FACTOR 0.00072	0.0033	0.0034	0.0032	0.0035	0.0029	0.0029	0.0032	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	4.5841	4.7288	4.4875	4.8439	4.0067	4.0788	4.4558	17
18	GPIF (¢/KWH)	0.0069	0.0069	0.0066	0.0077	0.0083	0.0086	0.0080	18
19	RECOVERY FACTOR including GPIF	4.5910	4.7357	4.4941	4.8516	4.0150	4.0874	4.4638	19
20	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	4.591	4.736	4.494	4.852	4.015	4.087	4.464	20

APPENDIX II
BASED ON TRADITIONAL METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

2011 Jan-Dec

	RS-1 standard	proposed inverted fuel factors	target fuel revenues	rounded
First 1000 kWh	36,523,505,744	0.04119114	1,504,444,827.66	4.119
All additional kWh	20,004,455,892	0.05119114	1,024,050,896.32	5.119
	56,527,961,636		2,528,495,723.98	
avg fuel factor	4.464			
RS-1 loss mult	1.00207		0.00	
average fuel Factor	4.473			
target fuel revenues	2,528,495,723.98			

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APPENDIX II
BASED ON TRADITIONAL METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

Generating System Comparative Data by Fuel Type

		1/1/2011	2/1/2011	3/1/2011	4/1/2011	5/1/2011	6/1/2011
	Fuel Cost of System Net Generation ($)						
1	Heavy Oil	$10,752,270	$4,133,400	$1,931,700	$10,687,500	$23,045,636	$21,909,728
2	Light Oil	$5,589,600	$316,300	$118,700	$589,200	$102,900	$0
3	Coal	$16,096,300	$14,244,700	$13,551,000	$15,102,600	$15,704,000	$7,306,900
4	Gas	$238,156,760	$217,171,868	$251,309,213	$260,274,907	$291,426,069	$305,190,762
5	Nuclear	$11,870,500	$10,572,900	$10,956,500	$11,364,800	$13,657,900	$14,387,400
6	***Total***	$282,465,430	$246,439,168	$277,867,113	$298,019,007	$343,936,505	$348,794,790
	System Net Generation (MWH)						
7	Heavy Oil	79,466	31,635	14,746	80,483	180,808	169,214
8	Light Oil	41,127	1,072	523	1,692	119	0
9	Coal	638,363	566,548	552,067	595,620	618,826	260,755
10	Gas	4,953,793	4,561,543	5,485,861	5,339,210	6,003,858	6,462,605
11	Nuclear	1,692,955	1,498,437	1,542,791	1,576,690	1,937,355	2,063,181
12	Solar	17,072	17,333	22,466	22,606	21,685	18,499
13	***Total***	7,422,776	6,676,568	7,618,454	7,616,301	8,762,651	8,974,254
	Units of Fuel Burned						
14	Heavy Oil (BBLS)	133,027	50,983	23,818	130,674	283,158	268,003
15	Light Oil (BBLS)	57,090	3,149	1,177	5,854	1,023	0
16	Coal (TONS)	337,507	300,696	303,836	319,881	331,955	119,657
17	Gas (MCF)	36,251,088	33,195,204	39,044,460	38,878,653	44,239,886	46,949,651
18	Nuclear (MBTU)	18,958,497	16,786,650	17,233,553	17,490,402	21,564,585	23,002,796
	BTU Burned (MMBTU)						
19	Heavy Oil	851,365	326,292	152,435	836,320	1,812,208	1,715,219
20	Light Oil	332,833	18,360	6,863	34,125	5,964	0
21	Coal	6,432,248	5,711,642	5,590,068	6,064,331	6,298,052	2,607,488
22	Gas	36,251,088	33,195,204	39,044,460	38,878,653	44,239,886	46,949,651
23	Nuclear	18,958,497	16,786,650	17,233,553	17,490,402	21,564,585	23,002,796
24	***Total***	62,826,031	56,038,148	62,027,379	63,303,831	73,920,695	74,275,154

Generating System Comparative Data by Fuel Type

		1/1/2011	2/1/2011	3/1/2011	4/1/2011	5/1/2011	6/1/2011
	Generation Mix (%MWH)						
25	Heavy Oil	1.07%	0.47%	0.19%	1.06%	2.06%	1.89%
26	Light Oil	0.55%	0.02%	0.01%	0.02%	0.00%	0.00%
27	Coal	8.60%	8.49%	7.25%	7.82%	7.06%	2.91%
28	Gas	66.74%	68.32%	72.01%	70.10%	68.52%	72.01%
29	Nuclear	22.81%	22.44%	20.25%	20.70%	22.11%	22.99%
30	Solar	0.23%	0.26%	0.29%	0.30%	0.25%	0.21%
31	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit						
32	Heavy Oil ($/BBL)	80.8277	81.0741	81.1025	81.7875	81.3879	81.7518
33	Light Oil ($/BBL)	97.9086	100.4446	100.8496	100.6491	100.5865	0.0000
34	Coal ($/ton)	47.6918	47.3724	44.5997	47.2132	47.3076	61.0654
35	Gas ($/MCF)	6.5696	6.5423	6.4365	6.6945	6.5874	6.5004
36	Nuclear ($/MBTU)	0.6261	0.6298	0.6358	0.6498	0.6333	0.6255
	Fuel Cost per MMBTU ($/MMBTU)						
37	Heavy Oil	12.6294	12.6678	12.6723	12.7792	12.7169	12.7737
38	Light Oil	16.7940	17.2277	17.2956	17.2659	17.2535	0.0000
39	Coal	2.5024	2.4940	2.4241	2.4904	2.4935	2.8023
40	Gas	6.5696	6.5423	6.4365	6.6945	6.5874	6.5004
41	Nuclear	0.6261	0.6298	0.6358	0.6498	0.6333	0.6255
	BTU burned per KWH (BTU/KWH)						
42	Heavy Oil	10,714	10,314	10,337	10,391	10,023	10,136
43	Light Oil	8,093	17,127	13,122	20,168	50,118	0
44	Coal	10,076	10,081	10,126	10,182	10,177	10,000
45	Gas	7,318	7,277	7,117	7,282	7,369	7,265
46	Nuclear	11,198	11,203	11,170	11,093	11,131	11,149
	Generated Fuel Cost per KWH (cents/KWH)						
47	Heavy Oil	13.5307	13.0659	13.0998	13.2792	12.7459	12.9479
48	Light Oil	13.5911	29.5056	22.6960	34.8227	86.4706	0.0000
49	Coal	2.5215	2.5143	2.4546	2.5356	2.5377	2.8022
50	Gas	4.8076	4.7609	4.5810	4.8748	4.8540	4.7224
51	Nuclear	0.7012	0.7056	0.7102	0.7208	0.7050	0.6973
52	***Total***	3.8054	3.6911	3.6473	3.9129	3.9250	3.8866

Generating System Comparative Data by Fuel Type

		7/1/2011	8/1/2011	9/1/2011	10/1/2011	11/1/2011	12/1/2011	Total
	Fuel Cost of System Net Generation ($)							
1	Heavy Oil	$24,071,805	$31,273,248	$36,584,010	$21,510,882	$223,600	$0	$186,123,779
2	Light Oil	$103,500	$306,700	$3,185,500	$463,600	$32,000	$0	$10,808,000
3	Coal	$11,468,800	$16,077,100	$15,564,100	$15,871,700	$15,505,400	$16,005,400	$172,498,000
4	Gas	$337,302,680	$338,811,298	$329,911,706	$321,957,472	$262,087,181	$247,560,937	$3,401,160,849
5	Nuclear	$14,867,000	$14,485,700	$10,575,300	$10,927,800	$10,813,500	$13,407,400	$147,886,700
6	***Total***	$387,813,785	$400,954,046	$395,820,616	$370,731,454	$288,661,681	$276,973,737	$3,918,477,328
	System Net Generation (MWH)							
7	Heavy Oil	182,726	236,207	275,732	160,395	1,753	0	1,413,165
8	Light Oil	119	615	11,544	746	139	0	57,696
9	Coal	427,285	635,939	615,424	628,274	618,109	637,812	6,795,022
10	Gas	7,197,724	7,171,022	6,910,812	6,669,758	5,389,896	4,876,069	71,022,150
11	Nuclear	2,131,953	2,073,053	1,474,201	1,523,340	1,507,883	1,909,016	20,930,855
12	Solar	19,570	19,202	17,458	18,202	16,407	17,267	227,767
13	***Total***	9,959,377	10,136,038	9,305,171	9,000,715	7,534,187	7,440,164	100,446,655
	Units of Fuel Burned							
14	Heavy Oil (BBLS)	291,076	377,006	439,111	258,205	2,649	0	2,257,710
15	Light Oil (BBLS)	1,023	3,015	31,074	4,487	307	0	108,199
16	Coal (TONS)	219,649	338,296	327,384	335,374	326,643	337,132	3,598,010
17	Gas (MCF)	52,255,767	52,235,720	50,763,765	48,556,298	37,814,626	34,263,417	514,448,533
18	Nuclear (MBTU)	23,769,566	23,122,445	16,531,670	17,082,733	16,913,476	21,332,233	233,788,606
	BTU Burned (MMBTU)							
19	Heavy Oil	1,862,884	2,412,847	2,810,304	1,652,514	16,952	0	14,449,340
20	Light Oil	5,964	17,576	181,163	26,159	1,790	0	630,797
21	Coal	4,331,086	6,456,984	6,248,694	6,385,623	6,227,602	6,426,834	68,780,652
22	Gas	52,255,767	52,235,720	50,763,765	48,556,298	37,814,626	34,263,417	514,448,533
23	Nuclear	23,769,566	23,122,445	16,531,670	17,082,733	16,913,476	21,332,233	233,788,606
24	***Total***	82,225,267	84,245,572	76,535,596	73,703,327	60,974,446	62,022,484	832,097,928

Generating System Comparative Data by Fuel Type

		7/1/2011	8/1/2011	9/1/2011	10/1/2011	11/1/2011	12/1/2011	Total
	Generation Mix (%MWH)							
25	Heavy Oil	1.83%	2.33%	2.96%	1.78%	0.02%	0.00%	1.41%
26	Light Oil	0.00%	0.01%	0.12%	0.01%	0.00%	0.00%	0.06%
27	Coal	4.29%	6.27%	6.61%	6.98%	8.20%	8.57%	6.76%
28	Gas	72.27%	70.75%	74.27%	74.10%	71.54%	65.54%	70.71%
29	Nuclear	21.41%	20.45%	15.84%	16.92%	20.01%	25.66%	20.84%
30	Solar	0.20%	0.19%	0.19%	0.20%	0.22%	0.23%	0.23%
31	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit							
32	Heavy Oil ($/BBL)	82.6994	82.9516	83.3138	83.3093	84.4092	0.0000	82.4392
33	Light Oil ($/BBL)	101.1730	101.7247	102.5134	103.3207	104.2345	0.0000	99.8900
34	Coal ($/ton)	52.2142	47.5238	47.5408	47.3254	47.4689	47.4752	47.9426
35	Gas ($/MCF)	6.4548	6.4862	6.4990	6.6306	6.9308	7.2252	6.6113
36	Nuclear ($/MBTU)	0.6255	0.6265	0.6397	0.6397	0.6393	0.6285	0.6326
	Fuel Cost per MMBTU ($/MMBTU)							
37	Heavy Oil	12.9218	12.9611	13.0178	13.0171	13.1902	0.0000	12.8811
38	Light Oil	17.3541	17.4499	17.5836	17.7224	17.8771	0.0000	17.1339
39	Coal	2.6480	2.4899	2.4908	2.4855	2.4898	2.4904	2.5079
40	Gas	6.4548	6.4862	6.4990	6.6306	6.9308	7.2252	6.6113
41	Nuclear	0.6255	0.6265	0.6397	0.6397	0.6393	0.6285	0.6326
	BTU burned per KWH (BTU/KWH)							
42	Heavy Oil	10,195	10,215	10,192	10,303	9,670	0	10,225
43	Light Oil	50,118	28,579	15,693	35,066	12,878	0	10,933
44	Coal	10,136	10,153	10,153	10,164	10,075	10,076	10,122
45	Gas	7,260	7,284	7,346	7,280	7,016	7,027	7,243
46	Nuclear	11,149	11,154	11,214	11,214	11,217	11,174	11,170
	Generated Fuel Cost per KWH (cents/KWH)							
47	Heavy Oil	13.1737	13.2398	13.2680	13.4112	12.7553	0.0000	13.1707
48	Light Oil	86.9748	49.8699	27.5944	62.1448	23.0216	0.0000	18.7327
49	Coal	2.6841	2.5281	2.5290	2.5262	2.5085	2.5094	2.5386
50	Gas	4.6862	4.7247	4.7738	4.8271	4.8626	5.0771	4.7889
51	Nuclear	0.6973	0.6988	0.7174	0.7174	0.7171	0.7023	0.7065
52	***Total***	3.8940	3.9557	4.2538	4.1189	3.8314	3.7227	3.9011

Date:
Company: Florida Power & Light

Schedule E4

Period: Jan-2011

Estimated For The Period of : 1/1/2011 Thru 1/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	380	9,153.00	9.23	93.0	33.03	11,284	Heavy Oil BBLS ->	15,057	6,399,947	96,364	1,200,889	13.12	79.76
2			16,956.20					Gas MMCF ->	198,256	1,000,000	198,256	1,299,709	7.67	6.56
3	TURKEY POINT 2	380	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	717	520,110.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	4,121,200	0.79	0.70
6	TURKEY POINT 4	717	520,110.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	3,579,600	0.69	0.61
7	TURKEY POINT 5	1,114	389,213.90	48.35	96.7	64.00	7,330	Gas MMCF ->	2,857,577	1,000,000	2,857,577	18,858,765	4.85	6.60
8	LAUDERDALE 4	447	20,165.00	29.18	98.1	75.65	8,315	Light Oil BBLS ->	25,239	5,830,065	147,145	2,440,100	12.10	96.68
9			88,384.00					Gas MMCF ->	739,386	1,000,000	739,386	4,918,651	5.57	6.65
10	LAUDERDALE 5	447	10,186.00	34.30	97.7	77.79	8,266	Light Oil BBLS ->	13,535	5,829,922	78,908	1,308,500	12.85	96.68
11			103,873.30					Gas MMCF ->	863,895	1,000,000	863,895	5,735,598	5.52	6.64
12	PT EVERGLADES 1	207	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	207	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	376	5,586.00	8.92	100.0	34.23	11,561	Heavy Oil BBLS ->	9,349	6,399,829	59,832	748,807	13.41	80.09
17			19,381.60					Gas MMCF ->	228,796	1,000,000	228,796	1,505,193	7.77	6.58
18	PT EVERGLADES 4	376	3,975.00	5.95	100.0	35.72	11,569	Heavy Oil BBLS ->	6,663	6,399,670	42,641	533,645	13.43	80.09
19			12,679.60					Gas MMCF ->	150,033	1,000,000	150,033	989,249	7.80	6.59
20	RIVIERA 3 (2)	275	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	286	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	853	618,763.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	6,798,424	1,000,000	6,798,424	4,004,900	0.65	0.59
25	ST LUCIE 2	726	33,972.00	6.29	6.3	97.50	10,987	Nuclear Othr ->	373,253	1,000,000	373,253	164,800	0.49	0.44
26	CAPE CANAVERAL 1 (2)	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	69	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,440	619,814.80	57.85	94.4	85.23	7,163	Gas MMCF ->	4,439,494	1,000,000	4,439,494	29,339,542	4.73	6.61
33	FORT MYERS 3A_B	328	698.00	17.65	93.5	91.20	14,235	Light Oil BBLS ->	1,587	5,829,238	9,251	158,100	22.65	99.62
34			20,840.30					Gas MMCF ->	297,346	1,000,000	297,346	1,977,972	9.49	6.65
35	SANFORD 3	140	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	955	343,777.30	48.38	96.8	85.71	7,370	Gas MMCF ->	2,533,744	1,000,000	2,533,744	16,687,420	4.85	6.59
37	SANFORD 5	952	342,694.30	48.38	96.2	85.71	7,418	Gas MMCF ->	2,542,000	1,000,000	2,542,000	16,685,307	4.87	6.56
38	PUTNAM 1	248	6,501.00	20.32	93.2	65.16	9,723	Light Oil BBLS ->	10,240	5,829,785	59,697	1,030,800	15.86	100.66

Date:
Company: Florida Power & Light

Schedule E4

Period: Jan-2011

Estimated For The Period of : 1/1/2011 Thru 1/31/2011

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	Plant Unit	Net Capb (MW)	Net Gen (MWH)	Capac FAC (%)	Equiv Avail FAC (%)	Net Out FAC (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Type	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (C/KWH)	Cost of Fuel ($/Unit)
39			30,988.20					Gas MMCF ->	304,798	1,000,000	304,798	2,019,764	6.52	6.63
40	PUTNAM 2	248	3,384.00	20.57	96.7	65.98	9,772	Light Oil BBLS ->	5,323	5,830,547	31,036	535,900	15.84	100.68
41			34,577.80					Gas MMCF ->	339,946	1,000,000	339,946	2,251,274	6.51	6.62
42	MANATEE 1	798	19,298.00	5.38	95.5	47.09	10,897	Heavy Oil BBLS ->	33,493	6,399,964	214,354	2,682,758	13.90	80.10
43			12,646.90					Gas MMCF ->	133,736	1,000,000	133,736	881,115	6.97	6.59
44	MANATEE 2	798	17,334.00	4.97	95.7	42.96	11,166	Heavy Oil BBLS ->	31,222	6,399,910	199,818	2,500,768	14.43	80.10
45			12,148.60					Gas MMCF ->	129,388	1,000,000	129,388	851,477	7.01	6.58
46	MANATEE 3	1,117	340,414.60	40.96	58.8	56.44	7,545	Gas MMCF ->	2,568,569	1,000,000	2,568,569	16,775,673	4.93	6.53
47	MARTIN 1	808	10,409.00	3.32	95.1	41.84	10,972	Heavy Oil BBLS ->	16,154	6,399,901	103,384	1,338,277	12.86	82.84
48			9,539.90					Gas MMCF ->	115,490	1,000,000	115,490	760,211	7.97	6.58
49	MARTIN 2	808	13,711.00	4.43	94.8	40.66	10,684	Heavy Oil BBLS ->	21,089	6,400,114	134,972	1,747,126	12.74	82.85
50			12,897.70					Gas MMCF ->	149,318	1,000,000	149,318	981,253	7.61	6.57
51	MARTIN 3	462	166,412.70	48.41	96.2	84.55	7,340	Gas MMCF ->	1,221,509	1,000,000	1,221,509	8,056,032	4.84	6.60
52	MARTIN 4	462	167,784.00	48.81	95.1	85.45	7,271	Gas MMCF ->	1,219,875	1,000,000	1,219,875	8,049,814	4.80	6.60
53	MARTIN 8 (1)	1,112	677,279.80	81.86	94.7	87.38	6,797	Gas MMCF ->	4,603,651	1,000,000	4,603,651	30,317,007	4.48	6.59
54	FORT MYERS 1-12	627	193.00	0.04	98.4	15.39	35,212	Light Oil BBLS ->	1,166	5,828,473	6,796	116,200	60.21	99.66
55	LAUDERDALE 1-24	766	0.00	0.02	91.74	15.01	28,017	Light Oil BBLS ->	0		0	0		
56			115.00					Gas MMCF ->	3,222	1,000,000	3,222	20,985	18.25	6.51
57	EVERGLADES 1-12	383	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0		
58			0.00					Gas MMCF ->	0		0	0		
59	ST JOHNS 10	124	88,904.00	96.37	95.8	96.37	9,801	Coal TONS ->	34,771	25,060,079	871,364	2,766,800	3.11	79.57
60	ST JOHNS 20	124	89,728.00	97.26	97.2	97.26	9,716	Coal TONS ->	34,788	25,060,337	871,799	2,768,200	3.09	79.57
61	SCHERER 4	632	459,731.00	95.55	95.6	97.77	10,200	Coal TONS ->	267,948	17,499,981	4,689,085	10,561,300	2.30	39.42
62	WCEC_01	1,335	784,136.40	78.95	90.0	78.95	6,865	Gas MMCF ->	5,383,033	1,000,000	5,383,033	35,102,764	4.48	6.52
63	WCEC_02	1,335	759,880.60	76.51	94.5	76.51	6,880	Gas MMCF ->	5,228,029	1,000,000	5,228,029	34,091,984	4.49	6.52
64	WCEC_03	1,335	0.00	0.00	0.0			Gas MMCF ->	0		0	0		
65	DESOTO	25	3,212.00					SOLAR						
66	SPACE COAST	10	1,215.00					SOLAR						
67														
68	TOTAL	25,812	7,422,775.50				8,464	Gas MMCF ->	36,251,088		62,826,031	282,465,430	3.81	
69								Nuclear Othr ->	18,958,497					
70								Coal TONS ->	337,507					
71		PeriodHours -->		744				Heavy Oil BBLS ->	133,027					
								Light Oil BBLS ->	57,090					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modernization construction

Date:
Company: Florida Power & Light

Schedule E4

Period: Feb-2011

Estimated For The Period of : 2/1/2011 Thru 2/28/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	380	10,693.00	11.72	93.0	34.84	11,099	Heavy Oil BBLS ->	17,432	6,399,897	111,563	1,393,200	13.03	79.92
2			19,231.10					Gas MMCF ->	220,576	1,000,000	220,576	1,443,895	7.51	6.55
3	TURKEY POINT 2	380	0.00	0.00	71.4			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	717	469,777.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,323,070	1,000,000	5,323,070	3,722,400	0.79	0.70
6	TURKEY POINT 4	717	469,777.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,323,070	1,000,000	5,323,070	3,233,200	0.69	0.61
7	TURKEY POINT 5	1,114	542,715.60	72.50	96.7	89.72	6,938	Gas MMCF ->	3,765,210	1,000,000	3,765,210	24,645,207	4.54	6.55
8	LAUDERDALE 4	447	0.00	36.00	98.1	85.80	8,108	Light Oil BBLS ->	0		0	0		
9			108,150.80					Gas MMCF ->	876,909	1,000,000	876,909	5,805,662	5.37	6.62
10	LAUDERDALE 5	447	0.00	40.12	97.7	87.25	8,078	Light Oil BBLS ->	0		0	0		
11			120,516.10					Gas MMCF ->	973,548	1,000,000	973,548	6,430,338	5.34	6.61
12	PT EVERGLADES 1	207	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	207	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	376	1,992.00	9.38	100.0	40.16	11,272	Heavy Oil BBLS ->	3,253	6,399,939	20,819	261,100	13.11	80.26
17			21,715.30					Gas MMCF ->	246,398	1,000,000	246,398	1,624,493	7.48	6.59
18	PT EVERGLADES 4	376	0.00	3.95	100.0	48.29	11,135	Heavy Oil BBLS ->	0		0	0		
19			9,986.50					Gas MMCF ->	111,193	1,000,000	111,193	737,206	7.38	6.63
20	RIVIERA 3 (2)	275	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	286	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	853	558,883.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	6,140,510	1,000,000	6,140,510	3,617,300	0.65	0.59
25	ST LUCIE 2	726	0.00	0.00	0.0			Nuclear Othr ->	0		0	0		
26	CAPE CANAVERAL 1 (2)	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	69	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,440	761,453.20	78.69	94.4	89.62	7,075	Gas MMCF ->	5,387,624	1,000,000	5,387,624	35,461,685	4.66	6.58
33	FORT MYERS 3A_B	328	906.00	25.41	93.5	93.82	13,972	Light Oil BBLS ->	2,034	5,829,892	11,858	204,300	22.55	100.44
34			27,098.10					Gas MMCF ->	379,418	1,000,000	379,418	2,502,941	9.24	6.60
35	SANFORD 3	140	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	955	285,224.70	44.44	88.1	85.58	7,416	Gas MMCF ->	2,115,267	1,000,000	2,115,267	13,844,427	4.85	6.55
37	SANFORD 5	952	297,759.40	46.54	96.2	92.54	7,349	Gas MMCF ->	2,188,341	1,000,000	2,188,341	14,298,522	4.80	6.53
38	PUTNAM 1	248	0.00	33.61	93.2	80.66	9,195	Light Oil BBLS ->	0		0	0		
39			56,008.00					Gas MMCF ->	514,979	1,000,000	514,979	3,390,924	6.05	6.58
40	PUTNAM 2	248	0.00	31.01	96.7	77.76	9,284	Light Oil BBLS ->	0		0	0		

Date:

Company: Florida Power & Light

Schedule E4

Period: Feb-2011

Estimated For The Period of : 2/1/2011 Thru 2/28/2011

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	Plant Unit	Net Capb (MW)	Net Gen (MWH)	Capac FAC (%)	Equiv Avail FAC (%)	Net Out FAC (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Type	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (C/KWH)	Cost of Fuel ($/Unit)
41			51,682.20					Gas MMCF ->	479,804	1,000,000	479,804	3,158,395	6.11	6.58
42	MANATEE 1	798	2,295.00	1.28	61.4	33.06	11,446	Heavy Oil BBLS ->	4,394	6,400,546	28,124	352,700	15.37	80.27
43			4,584.80					Gas MMCF ->	50,388	1,000,000	50,388	329,694	7.22	6.54
44	MANATEE 2	798	2,788.00	0.87	95.7	72.79	10,780	Heavy Oil BBLS ->	4,862	6,399,630	31,115	390,200	14.00	80.26
45			1,858.90					Gas MMCF ->	18,981	1,000,000	18,981	126,668	6.81	6.67
46	MANATEE 3	1,117	59,979.70	7.99	12.0	48.38	7,908	Gas MMCF ->	474,329	1,000,000	474,329	3,086,090	5.15	6.51
47	MARTIN 1	808	5,024.00	3.62	95.1	49.62	10,909	Heavy Oil BBLS ->	7,639	6,400,183	48,891	630,300	12.55	82.51
48			14,623.30					Gas MMCF ->	165,434	1,000,000	165,434	1,094,898	7.49	6.62
49	MARTIN 2	808	8,843.00	6.79	94.8	46.08	10,829	Heavy Oil BBLS ->	13,403	6,400,060	85,780	1,105,900	12.51	82.51
50			28,016.10					Gas MMCF ->	313,356	1,000,000	313,356	2,071,366	7.39	6.61
51	MARTIN 3	462	151,090.60	48.67	96.2	93.44	7,263	Gas MMCF ->	1,097,331	1,000,000	1,097,331	7,196,785	4.76	6.56
52	MARTIN 4	462	163,124.90	52.54	95.1	94.41	7,187	Gas MMCF ->	1,172,342	1,000,000	1,172,342	7,700,740	4.72	6.57
53	MARTIN 8 (1)	1,112	687,966.40	92.06	94.7	92.06	6,738	Gas MMCF ->	4,635,708	1,000,000	4,635,708	30,220,119	4.39	6.52
54	FORT MYERS 1-12	627	166.00	0.04	98.4	13.24	39,404	Light Oil BBLS ->	1,115	5,831,390	6,502	112,000	67.47	100.45
55	LAUDERDALE 1-24	766	0.00	0.00	91.74			Light Oil BBLS ->	0		0	0		
56			0.00					Gas MMCF ->	0		0	0		
57	EVERGLADES 1-12	383	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0		
58			0.00					Gas MMCF ->	0		0	0		
59	ST JOHNS 10	124	72,020.00	86.43	85.5	96.80	9,801	Coal TONS ->	28,167	25,059,715	705,857	2,241,300	3.11	79.57
60	ST JOHNS 20	124	80,650.00	96.79	97.2	96.79	9,721	Coal TONS ->	31,285	25,060,125	784,006	2,489,400	3.09	79.57
61	SCHERER 4	632	413,878.00	95.55	95.6	97.45	10,201	Coal TONS ->	241,244	17,500,037	4,221,779	9,514,000	2.30	39.44
62	WCEC_01	1,335	744,424.40	82.98	90.0	82.98	6,835	Gas MMCF ->	5,088,465	1,000,000	5,088,465	33,042,852	4.44	6.49
63	WCEC_02	1,335	416,715.20	46.45	58.5	57.07	7,006	Gas MMCF ->	2,919,608	1,000,000	2,919,608	18,958,959	4.55	6.49
64	WCEC_03	1,335	0.00	0.00	0.0			Gas MMCF ->	0		0	0		
65	DESOTO	25	3,665.00					SOLAR						
66	SPACE COAST	10	1,306.00					SOLAR						
67														
68	TOTAL	25,812	6,676,568.30				8,393	Gas MMCF ->	33,195,204		56,038,148	246,439,168	3.69	
69								Nuclear Othr ->	16,786,650					
70								Coal TONS ->	300,696					
71		PeriodHours -->		672				Heavy Oil BBLS ->	50,983					
								Light Oil BBLS ->	3,149					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modernization construction

Date:
Company: Florida Power & Light — Schedule E4

Period: Mar-2011

Estimated For The Period of : 3/1/2011 Thru 3/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	380	4,354.00	4.70	93.0	34.27	11,237	Heavy Oil BBLS ->	7,083	6,400,395	45,334	568,500	13.06	80.26
2			8,930.20					Gas MMCF ->	103,938	1,000,000	103,938	669,498	7.50	6.44
3	TURKEY POINT 2	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	717	520,110.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	4,121,200	0.79	0.70
6	TURKEY POINT 4	717	302,001.00	56.61	56.6	97.50	11,331	Nuclear Othr ->	3,421,958	1,000,000	3,421,958	2,078,500	0.69	0.61
7	TURKEY POINT 5	1,114	491,280.60	59.27	85.8	81.52	7,018	Gas MMCF ->	3,447,905	1,000,000	3,447,905	22,269,849	4.53	6.46
8	LAUDERDALE 4	447	0.00	9.96	34.8	80.57	8,277	Light Oil BBLS ->	0		0	0		
9			33,134.00					Gas MMCF ->	274,261	1,000,000	274,261	1,795,174	5.42	6.55
10	LAUDERDALE 5	447	0.00	26.96	97.7	87.58	8,152	Light Oil BBLS ->	0		0	0		
11			89,649.10					Gas MMCF ->	730,847	1,000,000	730,847	4,782,826	5.34	6.54
12	PT EVERGLADES 1	207	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	207	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	376	1,780.00	4.17	100.0	53.49	10,834	Heavy Oil BBLS ->	2,788	6,399,211	17,841	224,700	12.62	80.60
17			9,885.40					Gas MMCF ->	108,540	1,000,000	108,540	708,299	7.17	6.53
18	PT EVERGLADES 4	376	58.00	3.44	100.0	44.92	11,281	Heavy Oil BBLS ->	93	6,408,602	596	7,500	12.93	80.65
19			9,569.10					Gas MMCF ->	108,010	1,000,000	108,010	704,112	7.36	6.52
20	RIVIERA 3 (2)	275	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	286	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	853	618,763.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	6,798,424	1,000,000	6,798,424	4,004,900	0.65	0.59
25	ST LUCIE 2	726	101,917.00	18.87	18.9	97.50	10,987	Nuclear Othr ->	1,119,761	1,000,000	1,119,761	751,900	0.74	0.67
26	CAPE CANAVERAL 1 (2)	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	69	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,440	826,950.90	77.19	94.4	89.73	7,080	Gas MMCF ->	5,855,023	1,000,000	5,855,023	37,887,052	4.58	6.47
33	FORT MYERS 3A_B	328	523.00	16.02	93.5	93.12	13,998	Light Oil BBLS ->	1,177	5,830,926	6,863	118,700	22.70	100.85
34			19,026.60					Gas MMCF ->	266,766	1,000,000	266,766	1,744,967	9.17	6.54
35	SANFORD 3	140	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	955	300,606.10	42.31	82.7	81.76	7,478	Gas MMCF ->	2,248,064	1,000,000	2,248,064	14,438,418	4.80	6.42
37	SANFORD 5	952	301,851.80	42.62	96.2	94.09	7,345	Gas MMCF ->	2,217,197	1,000,000	2,217,197	14,229,207	4.71	6.42
38	PUTNAM 1	248	0.00	23.65	82.7	82.62	9,154	Light Oil BBLS ->	0		0	0		
39			43,644.20					Gas MMCF ->	399,511	1,000,000	399,511	2,610,593	5.98	6.53
40	PUTNAM 2	248	0.00	21.65	85.8	80.54	9,226	Light Oil BBLS ->	0		0	0		

Date:
Company: Florida Power & Light | Schedule E4

Period: Mar-2011

Estimated For The Period of : 3/1/2011 Thru 3/31/2011

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	Plant Unit	Net Capb (MW)	Net Gen (MWH)	Capac FAC (%)	Equiv Avail FAC (%)	Net Out FAC (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Type	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (C/KWH)	Cost of Fuel ($/Unit)
41			39,949.10					Gas MMCF ->	368,560	1,000,000	368,560	2,404,089	6.02	6.52
42	MANATEE 1	798	3,687.00	1.31	55.4	37.51	11,107	Heavy Oil BBLS ->	6,571	6,399,787	42,053	529,600	14.36	80.60
43			4,094.70					Gas MMCF ->	44,379	1,000,000	44,379	285,387	6.97	6.43
44	MANATEE 2	798	0.00	0.00	64.9			Heavy Oil BBLS ->	0		0	0		
45			0.00					Gas MMCF ->	0		0	0		
46	MANATEE 3	1,117	687,461.40	82.72	95.9	90.11	6,842	Gas MMCF ->	4,703,720	1,000,000	4,703,720	30,197,118	4.39	6.42
47	MARTIN 1	808	3,815.00	2.19	95.1	54.25	11,165	Heavy Oil BBLS ->	5,727	6,399,860	36,652	472,900	12.40	82.57
48			9,334.80					Gas MMCF ->	110,161	1,000,000	110,161	719,296	7.71	6.53
49	MARTIN 2	808	1,052.00	0.58	12.2	54.22	10,944	Heavy Oil BBLS ->	1,556	6,400,386	9,959	128,500	12.21	82.58
50			2,453.90					Gas MMCF ->	28,399	1,000,000	28,399	185,575	7.56	6.53
51	MARTIN 3	462	155,793.40	45.32	96.2	93.93	7,265	Gas MMCF ->	1,131,860	1,000,000	1,131,860	7,290,085	4.68	6.44
52	MARTIN 4	462	176,183.20	51.26	95.1	94.63	7,183	Gas MMCF ->	1,265,546	1,000,000	1,265,546	8,170,054	4.64	6.46
53	MARTIN 8 (1)	1,112	749,092.10	90.54	94.7	91.53	6,727	Gas MMCF ->	5,039,149	1,000,000	5,039,149	32,605,987	4.35	6.47
54	FORT MYERS 1-12	627	0.00	0.00	98.4			Light Oil BBLS ->	0		0	0		
55	LAUDERDALE 1-24	766	0.00	0.00	91.74			Light Oil BBLS ->	0		0	0		
56			0.00					Gas MMCF ->	0		0	0		
57	EVERGLADES 1-12	383	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0		
58			0.00					Gas MMCF ->	0		0	0		
59	ST JOHNS 10	124	8,063.00	8.74	9.3	90.30	9,844	Coal TONS ->	3,167	25,058,099	79,359	262,000	3.25	82.73
60	ST JOHNS 20	124	84,652.00	91.76	97.2	91.76	9,751	Coal TONS ->	32,937	25,060,115	825,405	2,724,600	3.22	82.72
61	SCHERER 4	632	459,352.00	95.55	95.6	97.69	10,200	Coal TONS ->	267,732	17,499,978	4,685,304	10,564,400	2.30	39.46
62	WCEC_01	1,335	825,241.80	83.09	90.0	83.09	6,841	Gas MMCF ->	5,645,408	1,000,000	5,645,408	36,034,028	4.37	6.38
63	WCEC_02	1,335	717,454.40	72.23	81.3	73.22	6,896	Gas MMCF ->	4,947,219	1,000,000	4,947,219	31,577,598	4.40	6.38
64	WCEC_03	1,335	0.00	0.00	0.0			Gas MMCF ->	0		0	0		
65	DESOTO	25	5,010.00					SOLAR						
66	SPACE COAST	10	1,730.00					SOLAR						
67														
68	TOTAL	25,812	7,618,453.80				8,142	Gas MMCF ->	39,044,460		62,027,379	277,867,113	3.65	
69								Nuclear Othr ->	17,233,553					
70								Coal TONS ->	303,836					
71		PeriodHours -->		744				Heavy Oil BBLS ->	23,818					
								Light Oil BBLS ->	1,177					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modernization construction

Date:
Company: Florida Power & Light — Schedule E4

Period: Apr-2011

Estimated For The Period of : 4/1/2011 Thru 4/30/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	378	4,071.00	3.02	21.7	64.03	10,433	Heavy Oil BBLS ->	6,201	6,400,258	39,688	502,500	12.34	81.04
2			4,158.40					Gas MMCF ->	46,168	1,000,000	46,168	315,089	7.58	6.82
3	TURKEY POINT 2	378	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	693	486,491.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	3,854,800	0.79	0.70
6	TURKEY POINT 4	693	0.00	0.00	0.0			Nuclear Othr ->	0		0	0		
7	TURKEY POINT 5	1,053	627,910.50	82.82	91.0	83.87	6,974	Gas MMCF ->	4,378,956	1,000,000	4,378,956	29,559,328	4.71	6.75
8	LAUDERDALE 4	438	0.00	17.60	49.1	90.52	8,183	Light Oil BBLS ->	0		0	0		
9			55,504.50					Gas MMCF ->	454,192	1,000,000	454,192	3,097,340	5.58	6.82
10	LAUDERDALE 5	438	0.00	40.21	97.7	92.49	8,139	Light Oil BBLS ->	0		0	0		
11			126,794.80					Gas MMCF ->	1,032,031	1,000,000	1,032,031	7,037,339	5.55	6.82
12	PT EVERGLADES 1	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
17			0.00					Gas MMCF ->	0		0	0		
18	PT EVERGLADES 4	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
19			0.00					Gas MMCF ->	0		0	0		
20	RIVIERA 3 (2)	273	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	284	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	839	588,980.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	6,471,126	1,000,000	6,471,126	3,812,100	0.65	0.59
25	ST LUCIE 2	714	501,219.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	5,506,882	1,000,000	5,506,882	3,697,900	0.74	0.67
26	CAPE CANAVERAL 1 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	68	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	137	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,349	388,097.80	39.96	42.5	43.52	7,435	Gas MMCF ->	2,885,627	1,000,000	2,885,627	19,390,190	5.00	6.72
33	FORT MYERS 3A_B	296	0.00	32.22	93.5	97.88	14,288	Light Oil BBLS ->	0		0	0		
34			34,333.40					Gas MMCF ->	490,543	1,000,000	490,543	3,338,693	9.72	6.81
35	SANFORD 3	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	905	500,384.50	76.79	96.8	92.00	7,241	Gas MMCF ->	3,623,396	1,000,000	3,623,396	24,279,592	4.85	6.70
37	SANFORD 5	901	383,628.60	59.14	96.2	95.47	7,333	Gas MMCF ->	2,813,060	1,000,000	2,813,060	18,770,096	4.89	6.67
38	PUTNAM 1	239	0.00	28.31	93.2	84.93	9,235	Light Oil BBLS ->	0		0	0		
39			48,716.40					Gas MMCF ->	449,904	1,000,000	449,904	3,062,629	6.29	6.81
40	PUTNAM 2	239	0.00	24.57	96.7	85.87	9,254	Light Oil BBLS ->	0		0	0		

Date:

Company: Florida Power & Light

Schedule E4

Period: Apr-2011

Estimated For The Period of : 4/1/2011 Thru 4/30/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
41			42,276.90					Gas MMCF ->	391,216	1,000,000	391,216	2,662,736	6.30	6.81
42	MANATEE 1	788	14,653.00	4.30	95.5	75.59	10,810	Heavy Oil BBLS ->	25,552	6,400,047	163,534	2,079,400	14.19	81.38
43			9,768.90					Gas MMCF ->	100,474	1,000,000	100,474	688,426	7.05	6.85
44	MANATEE 2	788	27,772.00	8.57	95.7	65.65	10,766	Heavy Oil BBLS ->	47,940	6,399,958	306,814	3,901,300	14.05	81.38
45			20,855.30					Gas MMCF ->	216,697	1,000,000	216,697	1,479,535	7.09	6.83
46	MANATEE 3	1,058	677,606.90	88.96	95.9	88.95	6,902	Gas MMCF ->	4,677,169	1,000,000	4,677,169	31,164,357	4.60	6.66
47	MARTIN 1	802	9,630.00	6.52	63.4	48.37	10,921	Heavy Oil BBLS ->	14,764	6,400,230	94,493	1,217,600	12.64	82.47
48			28,002.60					Gas MMCF ->	316,501	1,000,000	316,501	2,146,729	7.67	6.78
49	MARTIN 2	802	24,357.00	14.41	63.2	67.80	10,526	Heavy Oil BBLS ->	36,217	6,400,061	231,791	2,986,700	12.26	82.47
50			58,833.00					Gas MMCF ->	643,886	1,000,000	643,886	4,391,540	7.46	6.82
51	MARTIN 3	431	158,962.00	51.22	96.2	96.55	7,304	Gas MMCF ->	1,161,000	1,000,000	1,161,000	7,706,703	4.85	6.64
52	MARTIN 4	431	200,345.40	64.56	95.1	94.10	7,200	Gas MMCF ->	1,442,530	1,000,000	1,442,530	9,680,908	4.83	6.71
53	MARTIN 8 (1)	1,052	509,989.70	67.33	69.5	91.81	6,836	Gas MMCF ->	3,486,471	1,000,000	3,486,471	23,560,360	4.62	6.76
54	FORT MYERS 1-12	552	1,692.00	0.43	98.4	38.29	20,180	Light Oil BBLS ->	5,854	5,829,347	34,125	589,200	34.82	100.65
55	LAUDERDALE 1-24	684	0.00	0.05	91.74	16.81	27,791	Light Oil BBLS ->	0		0	0		
56			231.00					Gas MMCF ->	6,392	1,000,000	6,392	42,456	18.38	6.64
57	EVERGLADES 1-12	342	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0		
58			0.00					Gas MMCF ->	0		0	0		
59	ST JOHNS 10	124	77,579.00	86.89	95.8	86.89	9,968	Coal TONS ->	30,859	25,060,242	773,334	2,455,500	3.17	79.57
60	ST JOHNS 20	124	78,195.00	87.58	97.2	87.58	9,882	Coal TONS ->	30,835	25,059,737	772,717	2,453,600	3.14	79.57
61	SCHERER 4	626	439,846.00	95.55	95.6	97.59	10,272	Coal TONS ->	258,187	17,500,029	4,518,280	10,193,500	2.32	39.48
62	WCEC_01	1,219	747,436.00	85.16	90.0	85.16	6,939	Gas MMCF ->	5,186,644	1,000,000	5,186,644	34,317,141	4.59	6.62
63	WCEC_02	1,219	730,515.10	83.23	94.5	83.23	6,948	Gas MMCF ->	5,075,796	1,000,000	5,075,796	33,583,719	4.60	6.62
64	WCEC_03	1,219	0.00	0.00	0.0			Gas MMCF ->	0		0	0		
65	DESOTO	25	5,598.00					SOLAR						
66	SPACE COAST	10	1,866.00					SOLAR						
67														
68	TOTAL	24,628	7,616,300.70				8,312	Gas MMCF ->	38,878,653		63,303,831	298,019,007	3.91	
69								Nuclear Othr ->	17,490,402					
70								Coal TONS ->	319,881					
71		PeriodHours -->		720				Heavy Oil BBLS ->	130,674					
								Light Oil BBLS ->	5,854					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modernization construction

Date:
Company: Florida Power & Light | Schedule E4

Period: May-2011

Estimated For The Period of : 5/1/2011 Thru 5/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	378	38,820.00	24.64	93.0	75.75	10,240	Heavy Oil BBLS ->	58,615	6,400,034	375,138	4,709,677	12.13	80.35
2			30,472.10					Gas MMCF ->	334,389	1,000,000	334,389	2,245,810	7.37	6.72
3	TURKEY POINT 2	378	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	693	502,707.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,983,300	0.79	0.70
6	TURKEY POINT 4	693	308,109.00	59.76	59.8	97.50	11,331	Nuclear Othr ->	3,491,163	1,000,000	3,491,163	1,914,300	0.62	0.55
7	TURKEY POINT 5	1,053	698,194.80	89.12	96.7	89.12	6,928	Gas MMCF ->	4,836,959	1,000,000	4,836,959	32,046,543	4.59	6.63
8	LAUDERDALE 4	438	0.00	40.36	98.1	94.71	8,147	Light Oil BBLS ->	0		0	0		
9			131,506.10					Gas MMCF ->	1,071,410	1,000,000	1,071,410	7,201,013	5.48	6.72
10	LAUDERDALE 5	438	0.00	45.59	97.7	95.00	8,120	Light Oil BBLS ->	0		0	0		
11			148,555.40					Gas MMCF ->	1,206,267	1,000,000	1,206,267	8,091,784	5.45	6.71
12	PT EVERGLADES 1	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
17			0.00					Gas MMCF ->	0		0	0		
18	PT EVERGLADES 4	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
19			0.00					Gas MMCF ->	0		0	0		
20	RIVIERA 3 (2)	273	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	284	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	839	608,613.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	3,939,200	0.65	0.59
25	ST LUCIE 2	714	517,926.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	3,821,100	0.74	0.67
26	CAPE CANAVERAL 1 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	68	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	137	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,349	547,385.00	54.54	57.5	59.76	7,453	Gas MMCF ->	4,079,389	1,000,000	4,079,389	26,974,070	4.93	6.61
33	FORT MYERS 3A_B	296	0.00	37.50	93.5	97.88	14,327	Light Oil BBLS ->	0		0	0		
34			41,287.00					Gas MMCF ->	591,512	1,000,000	591,512	3,953,364	9.58	6.68
35	SANFORD 3	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	905	589,257.70	87.52	96.8	90.43	7,214	Gas MMCF ->	4,250,964	1,000,000	4,250,964	27,926,430	4.74	6.57
37	SANFORD 5	901	476,689.30	71.11	96.2	94.31	7,295	Gas MMCF ->	3,477,568	1,000,000	3,477,568	22,812,522	4.79	6.56
38	PUTNAM 1	239	0.00	34.70	93.2	99.30	8,954	Light Oil BBLS ->	0		0	0		
39			61,703.10					Gas MMCF ->	552,517	1,000,000	552,517	3,698,877	5.99	6.69
40	PUTNAM 2	239	0.00	33.64	96.7	99.32	8,980	Light Oil BBLS ->	0		0	0		

Date:
Company: Florida Power & Light Schedule E4

Period: May-2011

Estimated For The Period of : 5/1/2011 Thru 5/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
41			59,816.80					Gas MMCF ->	537,155	1,000,000	537,155	3,592,294	6.01	6.69
42	MANATEE 1	788	16,398.00	4.66	95.5	72.26	10,850	Heavy Oil BBLS ->	28,798	6,399,924	184,305	2,323,545	14.17	80.68
43			10,932.20					Gas MMCF ->	112,214	1,000,000	112,214	756,158	6.92	6.74
44	MANATEE 2	788	38,258.00	10.88	95.7	76.34	10,736	Heavy Oil BBLS ->	66,006	6,400,009	422,439	5,325,905	13.92	80.69
45			25,505.30					Gas MMCF ->	262,107	1,000,000	262,107	1,766,256	6.93	6.74
46	MANATEE 3	1,058	710,893.00	90.31	95.9	90.31	6,886	Gas MMCF ->	4,894,926	1,000,000	4,894,926	32,143,485	4.52	6.57
47	MARTIN 1	802	35,182.00	18.95	95.1	80.09	10,519	Heavy Oil BBLS ->	52,516	6,399,954	336,100	4,325,653	12.30	82.37
48			77,866.80					Gas MMCF ->	853,073	1,000,000	853,073	5,733,152	7.36	6.72
49	MARTIN 2	802	52,150.00	28.75	94.8	76.68	10,436	Heavy Oil BBLS ->	77,223	6,399,984	494,226	6,360,856	12.20	82.37
50			119,422.20					Gas MMCF ->	1,296,363	1,000,000	1,296,363	8,711,567	7.29	6.72
51	MARTIN 3	431	187,922.00	58.60	96.2	93.97	7,285	Gas MMCF ->	1,368,977	1,000,000	1,368,977	8,929,689	4.75	6.52
52	MARTIN 4	431	112,192.00	34.99	39.9	91.02	7,167	Gas MMCF ->	804,059	1,000,000	804,059	5,308,989	4.73	6.60
53	MARTIN 8 (1)	1,052	417,482.50	53.34	55.0	93.82	6,796	Gas MMCF ->	2,837,233	1,000,000	2,837,233	18,836,063	4.51	6.64
54	FORT MYERS 1-12	552	119.00	0.03	90.2	10.78	50,445	Light Oil BBLS ->	1,023	5,829,912	5,964	102,900	86.47	100.59
55	LAUDERDALE 1-24	684	0.00	0.00	91.74			Light Oil BBLS ->	0		0	0		
56			0.00					Gas MMCF ->	0		0	0		
57	EVERGLADES 1-12	342	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0		
58			0.00					Gas MMCF ->	0		0	0		
59	ST JOHNS 1O	124	81,539.00	88.38	95.8	88.38	9,956	Coal TONS ->	32,394	25,059,826	811,788	2,577,600	3.16	79.57
60	ST JOHNS 2O	124	81,919.00	88.80	97.2	88.80	9,871	Coal TONS ->	32,269	25,059,717	808,652	2,567,700	3.13	79.57
61	SCHERER 4	626	455,368.00	95.55	95.6	97.77	10,272	Coal TONS ->	267,292	17,500,007	4,677,612	10,558,700	2.32	39.50
62	WCEC_01	1,219	792,222.30	87.35	90.0	87.35	6,918	Gas MMCF ->	5,480,382	1,000,000	5,480,382	35,634,940	4.50	6.50
63	WCEC_02	1,219	778,315.60	85.82	94.5	85.82	6,928	Gas MMCF ->	5,392,425	1,000,000	5,392,425	35,063,062	4.50	6.50
64	WCEC_03	1,219	0.00	0.00	0.0			Gas MMCF ->	0		0	0		
65	DESOTO	25	5,978.00					SOLAR						
66	SPACE COAST	10	1,944.00					SOLAR						
67														
68	TOTAL	24,628	8,762,651.20				8,436	Gas MMCF ->	44,239,886		73,920,695	343,936,505	3.93	
69		=======	=======				=======	Nuclear Othr ->	21,564,585		=======	=======	=======	
70								Coal TONS ->	331,955					
71		PeriodHours -->		744				Heavy Oil BBLS ->	283,158					
								Light Oil BBLS ->	1,023					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modernization construction

APPENDIX II

Date:
Company: Florida Power & Light — Schedule E4

Period: Jun-2011

Estimated For The Period of : 6/1/2011 Thru 6/30/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	378	33,289.00	21.40	93.0	77.02	10,256	Heavy Oil BBLS ->	50,335	6,400,020	322,145	4,081,537	12.26	81.09
2			24,940.50					Gas MMCF ->	275,029	1,000,000	275,029	1,818,887	7.29	6.61
3	TURKEY POINT 2	378	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	693	486,491.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	3,854,800	0.79	0.70
6	TURKEY POINT 4	693	486,491.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	3,022,600	0.62	0.55
7	TURKEY POINT 5	1,053	688,369.70	90.79	96.7	90.79	6,911	Gas MMCF ->	4,757,441	1,000,000	4,757,441	31,043,707	4.51	6.53
8	LAUDERDALE 4	438	0.00	33.73	98.1	93.77	8,185	Light Oil BBLS ->	0		0	0		
9			106,372.70					Gas MMCF ->	870,680	1,000,000	870,680	5,773,582	5.43	6.63
10	LAUDERDALE 5	438	0.00	36.33	97.7	94.09	8,166	Light Oil BBLS ->	0		0	0		
11			114,567.30					Gas MMCF ->	935,503	1,000,000	935,503	6,201,689	5.41	6.63
12	PT EVERGLADES 1	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
17			0.00					Gas MMCF ->	0		0	0		
18	PT EVERGLADES 4	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
19			0.00					Gas MMCF ->	0		0	0		
20	RIVIERA 3 (2)	273	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	284	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	839	588,980.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	6,471,126	1,000,000	6,471,126	3,812,100	0.65	0.59
25	ST LUCIE 2	714	501,219.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	5,506,882	1,000,000	5,506,882	3,697,900	0.74	0.67
26	CAPE CANAVERAL 1 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	68	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	137	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,349	653,097.40	67.24	76.3	79.24	7,177	Gas MMCF ->	4,686,993	1,000,000	4,686,993	30,526,066	4.67	6.51
33	FORT MYERS 3A_B	296	0.00	29.23	93.5	97.88	14,346	Light Oil BBLS ->	0		0	0		
34			31,146.40					Gas MMCF ->	446,825	1,000,000	446,825	2,962,255	9.51	6.63
35	SANFORD 3	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	905	383,269.10	58.82	96.8	96.03	7,287	Gas MMCF ->	2,792,985	1,000,000	2,792,985	18,009,517	4.70	6.45
37	SANFORD 5	901	279,615.10	43.10	80.2	81.88	7,596	Gas MMCF ->	2,123,916	1,000,000	2,123,916	13,683,614	4.89	6.44
38	PUTNAM 1	239	0.00	33.41	93.2	99.00	8,951	Light Oil BBLS ->	0		0	0		
39			57,494.70					Gas MMCF ->	514,623	1,000,000	514,623	3,411,337	5.93	6.63
40	PUTNAM 2	239	0.00	29.58	96.7	99.05	8,980	Light Oil BBLS ->	0		0	0		

Date:
Company: Florida Power & Light

Schedule E4

Period: Jun-2011

Estimated For The Period of : 6/1/2011 Thru 6/30/2011

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	Plant Unit	Net Capb (MW)	Net Gen (MWH)	Capac FAC (%)	Equiv Avail FAC (%)	Net Out FAC (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Type	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (C/KWH)	Cost of Fuel ($/Unit)
41			50,897.10					Gas MMCF ->	457,056	1,000,000	457,056	3,029,831	5.95	6.63
42	MANATEE 1	788	21,519.00	6.32	95.5	71.12	10,865	Heavy Oil BBLS ->	37,876	6,399,910	242,403	3,084,062	14.33	81.43
43			14,346.10					Gas MMCF ->	147,283	1,000,000	147,283	977,681	6.81	6.64
44	MANATEE 2	788	38,250.00	11.24	95.7	77.05	10,802	Heavy Oil BBLS ->	66,641	6,399,964	426,500	5,426,296	14.19	81.43
45			25,500.20					Gas MMCF ->	262,150	1,000,000	262,150	1,740,254	6.82	6.64
46	MANATEE 3	1,058	698,230.90	91.66	95.9	91.66	6,874	Gas MMCF ->	4,799,467	1,000,000	4,799,467	31,601,103	4.53	6.58
47	MARTIN 1	802	34,797.00	19.42	95.1	78.13	10,598	Heavy Oil BBLS ->	51,953	6,400,054	332,502	4,278,252	12.29	82.35
48			77,359.50					Gas MMCF ->	856,168	1,000,000	856,168	5,666,178	7.32	6.62
49	MARTIN 2	802	41,359.00	23.45	94.8	83.19	10,419	Heavy Oil BBLS ->	61,198	6,400,029	391,669	5,039,581	12.18	82.35
50			94,077.30					Gas MMCF ->	1,019,448	1,000,000	1,019,448	6,748,747	7.17	6.62
51	MARTIN 3	431	125,784.00	40.53	96.2	96.64	7,343	Gas MMCF ->	923,599	1,000,000	923,599	5,931,693	4.72	6.42
52	MARTIN 4	431	62,488.00	20.14	41.2	96.66	7,246	Gas MMCF ->	452,780	1,000,000	452,780	2,922,709	4.68	6.46
53	MARTIN 8 (1)	1,052	689,239.50	91.00	94.7	94.13	6,894	Gas MMCF ->	4,751,481	1,000,000	4,751,481	30,955,249	4.49	6.51
54	FORT MYERS 1-12	552	0.00	0.00	94.6			Light Oil BBLS ->	0		0	0		
55	LAUDERDALE 1-24	684	0.00	0.00	91.74			Light Oil BBLS ->	0		0	0		
56			0.00					Gas MMCF ->	0		0	0		
57	EVERGLADES 1-12	342	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0		
58			0.00					Gas MMCF ->	0		0	0		
59	ST JOHNS 10	124	85,849.00	95.77	95.8	96.16	9,903	Coal TONS ->	33,925	25,059,632	850,148	2,628,200	3.06	77.47
60	ST JOHNS 20	124	86,771.00	97.19	97.2	97.19	9,819	Coal TONS ->	33,998	25,060,121	851,994	2,633,900	3.04	77.47
61	SCHERER 4	626	88,135.00	19.11	19.1	97.77	10,272	Coal TONS ->	51,734	17,500,019	905,346	2,044,800	2.32	39.53
62	WCEC_01	1,219	780,105.40	88.88	90.0	88.88	6,910	Gas MMCF ->	5,390,229	1,000,000	5,390,229	35,060,798	4.49	6.50
63	WCEC_02	1,219	769,507.60	87.68	94.5	87.68	6,913	Gas MMCF ->	5,319,357	1,000,000	5,319,357	34,051,719	4.43	6.40
64	WCEC_03	1,219	747,764.40	85.20	95.2	86.16	6,909	Gas MMCF ->	5,166,641	1,000,000	5,166,641	33,074,147	4.42	6.40
65	DESOTO	25	5,237.00					SOLAR						
66	SPACE COAST	10	1,694.00					SOLAR						
67														
68	TOTAL	24,628	8,974,253.90				8,276	Gas MMCF ->	46,949,651		74,275,154	348,794,790	3.89	
69								Nuclear Othr ->	23,002,796					
70								Coal TONS ->	119,657					
71		PeriodHours -->		720				Heavy Oil BBLS ->	268,003					
								Light Oil BBLS ->	0					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modernization construction

Date:
Company: Florida Power & Light

Schedule E4

Period: Jul-2011

Estimated For The Period of : 7/1/2011 Thru 7/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	378	26,084.00	25.08	93.0	78.39	10,299	Heavy Oil BBLS ->	39,380	6,400,000	252,032	3,228,943	12.38	81.99
2			44,440.40					Gas MMCF ->	474,277	1,000,000	474,277	3,114,299	7.01	6.57
3	TURKEY POINT 2	378	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	693	502,707.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,983,300	0.79	0.70
6	TURKEY POINT 4	693	502,707.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,123,400	0.62	0.55
7	TURKEY POINT 5	1,053	654,923.00	83.60	88.9	84.51	6,956	Gas MMCF ->	4,555,452	1,000,000	4,555,452	29,565,642	4.51	6.49
8	LAUDERDALE 4	438	0.00	34.15	98.1	94.12	8,191	Light Oil BBLS ->	0		0	0		
9			111,301.30					Gas MMCF ->	911,642	1,000,000	911,642	5,994,748	5.39	6.58
10	LAUDERDALE 5	438	0.00	39.31	97.7	94.65	8,154	Light Oil BBLS ->	0		0	0		
11			128,101.40					Gas MMCF ->	1,044,510	1,000,000	1,044,510	6,869,432	5.36	6.58
12	PT EVERGLADES 1	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
17			0.00					Gas MMCF ->	0		0	0		
18	PT EVERGLADES 4	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
19			0.00					Gas MMCF ->	0		0	0		
20	RIVIERA 3 (2)	273	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	284	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	839	608,613.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	3,939,200	0.65	0.59
25	ST LUCIE 2	714	517,926.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	3,821,100	0.74	0.67
26	CAPE CANAVERAL 1 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	68	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	137	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,349	911,357.70	90.80	94.4	90.80	7,107	Gas MMCF ->	6,477,392	1,000,000	6,477,392	41,854,598	4.59	6.46
33	FORT MYERS 3A_B	296	0.00	25.52	51.3	97.88	14,330	Light Oil BBLS ->	0		0	0		
34			28,104.20					Gas MMCF ->	402,739	1,000,000	402,739	2,649,545	9.43	6.58
35	SANFORD 3	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	905	471,617.20	70.04	96.8	94.24	7,251	Gas MMCF ->	3,419,601	1,000,000	3,419,601	21,894,320	4.64	6.40
37	SANFORD 5	901	380,093.10	56.70	95.4	96.98	7,352	Gas MMCF ->	2,794,432	1,000,000	2,794,432	17,900,060	4.71	6.41
38	PUTNAM 1	239	0.00	34.30	93.2	99.30	8,941	Light Oil BBLS ->	0		0	0		
39			60,991.20					Gas MMCF ->	545,321	1,000,000	545,321	3,586,781	5.88	6.58
40	PUTNAM 2	239	0.00	32.42	96.7	99.27	8,973	Light Oil BBLS ->	0		0	0		

Date:
Company: Florida Power & Light — Schedule E4

Period: Jul-2011

Estimated For The Period of : 7/1/2011 Thru 7/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
41			57,652.40					Gas MMCF ->	517,313	1,000,000	517,313	3,402,343	5.90	6.58
42	MANATEE 1	788	26,875.00	7.64	95.5	71.05	10,863	Heavy Oil BBLS ->	47,296	6,400,013	302,695	3,894,041	14.49	82.33
43			17,916.70					Gas MMCF ->	183,887	1,000,000	183,887	1,210,574	6.76	6.58
44	MANATEE 2	788	46,347.00	13.18	95.7	78.42	10,765	Heavy Oil BBLS ->	80,290	6,400,000	513,856	6,610,579	14.26	82.33
45			30,898.00					Gas MMCF ->	317,699	1,000,000	317,699	2,091,453	6.77	6.58
46	MANATEE 3	1,058	723,281.50	91.89	95.9	91.89	6,870	Gas MMCF ->	4,968,632	1,000,000	4,968,632	32,623,679	4.51	6.57
47	MARTIN 1	802	39,878.00	21.35	95.1	80.64	10,551	Heavy Oil BBLS ->	59,585	6,399,966	381,342	4,963,377	12.45	83.30
48			87,528.00					Gas MMCF ->	962,862	1,000,000	962,862	6,320,569	7.22	6.56
49	MARTIN 2	802	43,542.00	24.05	94.8	80.60	10,484	Heavy Oil BBLS ->	64,525	6,399,985	412,959	5,374,865	12.34	83.30
50			99,968.20					Gas MMCF ->	1,091,518	1,000,000	1,091,518	7,162,577	7.16	6.56
51	MARTIN 3	431	125,368.00	39.10	96.2	96.64	7,350	Gas MMCF ->	921,420	1,000,000	921,420	5,866,972	4.68	6.37
52	MARTIN 4	431	165,996.90	51.77	95.1	96.05	7,226	Gas MMCF ->	1,199,449	1,000,000	1,199,449	7,684,980	4.63	6.41
53	MARTIN 8 (1)	1,052	724,999.40	92.63	94.7	93.64	6,887	Gas MMCF ->	4,993,013	1,000,000	4,993,013	32,408,916	4.47	6.49
54	FORT MYERS 1-12	552	119.00	0.03	98.4	10.78	50,445	Light Oil BBLS ->	1,023	5,829,912	5,964	103,500	86.97	101.17
55	LAUDERDALE 1-24	684	0.00	0.00	91.74			Light Oil BBLS ->	0		0	0		
56			0.00					Gas MMCF ->	0		0	0		
57	EVERGLADES 1-12	342	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0		
58			0.00					Gas MMCF ->	0		0	0		
59	ST JOHNS 1O	124	81,293.00	88.12	95.8	88.12	9,957	Coal TONS ->	32,301	25,060,277	809,472	2,672,000	3.29	82.72
60	ST JOHNS 2O	124	81,587.00	88.44	97.2	88.44	9,874	Coal TONS ->	32,146	25,060,070	805,581	2,659,100	3.26	82.72
61	SCHERER 4	626	264,405.00	55.48	55.5	97.77	10,272	Coal TONS ->	155,202	17,499,987	2,716,033	6,137,700	2.32	39.55
62	WCEC_01	1,219	806,670.30	88.94	90.0	88.94	6,901	Gas MMCF ->	5,566,700	1,000,000	5,566,700	35,879,750	4.45	6.45
63	WCEC_02	1,219	795,575.40	87.72	94.5	87.72	6,906	Gas MMCF ->	5,494,578	1,000,000	5,494,578	34,868,520	4.38	6.35
64	WCEC_03	1,219	783,532.00	86.39	95.4	86.39	6,909	Gas MMCF ->	5,413,330	1,000,000	5,413,330	34,352,920	4.38	6.35
65	DESOTO	25	5,184.00					SOLAR						
66	SPACE COAST	10	1,794.00					SOLAR						
67														
68	TOTAL	24,628	9,959,377.30				8,256	Gas MMCF ->	52,255,767		82,225,267	387,813,785	3.89	
69								Nuclear Othr ->	23,769,566					
70								Coal TONS ->	219,649					
71		PeriodHours -->		744				Heavy Oil BBLS ->	291,076					
								Light Oil BBLS ->	1,023					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modemization construction

APPENDIX II

Date:
Company: Florida Power & Light

Schedule E4

Period: Aug-2011

Estimated For The Period of : 8/1/2011 Thru 8/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	378	43,450.00	25.51	93.0	85.51	10,134	Heavy Oil BBLS ->	65,300	6,399,985	417,919	5,370,329	12.36	82.24
2			56,609.60					Gas MMCF ->	595,126	1,000,000	595,126	3,929,382	6.94	6.60
3	TURKEY POINT 2	378	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	693	502,707.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,983,300	0.79	0.70
6	TURKEY POINT 4	693	502,707.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,123,400	0.62	0.55
7	TURKEY POINT 5	1,053	714,298.80	91.18	96.7	91.18	6,905	Gas MMCF ->	4,932,082	1,000,000	4,932,082	32,046,080	4.49	6.50
8	LAUDERDALE 4	438	0.00	33.96	98.1	94.64	8,192	Light Oil BBLS ->	0		0	0		
9			110,677.00					Gas MMCF ->	906,640	1,000,000	906,640	5,990,218	5.41	6.61
10	LAUDERDALE 5	438	0.00	38.91	97.7	94.92	8,156	Light Oil BBLS ->	0		0	0		
11			126,801.40					Gas MMCF ->	1,034,203	1,000,000	1,034,203	6,834,012	5.39	6.61
12	PT EVERGLADES 1	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
17			0.00					Gas MMCF ->	0		0	0		
18	PT EVERGLADES 4	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
19			0.00					Gas MMCF ->	0		0	0		
20	RIVIERA 3 (2)	273	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	284	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	839	549,713.00	88.06	88.1	97.50	10,987	Nuclear Othr ->	6,039,712	1,000,000	6,039,712	3,557,900	0.65	0.59
25	ST LUCIE 2	714	517,926.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	3,821,100	0.74	0.67
26	CAPE CANAVERAL 1 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	68	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	137	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,349	918,667.60	91.53	94.4	91.53	7,100	Gas MMCF ->	6,522,711	1,000,000	6,522,711	42,352,243	4.61	6.49
33	FORT MYERS 3A_B	296	0.00	31.97	93.5	97.88	14,333	Light Oil BBLS ->	0		0	0		
34			35,202.70					Gas MMCF ->	504,540	1,000,000	504,540	3,334,949	9.47	6.61
35	SANFORD 3	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	905	368,429.60	54.72	96.8	97.39	7,308	Gas MMCF ->	2,692,572	1,000,000	2,692,572	17,305,497	4.70	6.43
37	SANFORD 5	901	286,227.10	42.70	92.3	93.71	7,446	Gas MMCF ->	2,131,316	1,000,000	2,131,316	13,704,926	4.79	6.43
38	PUTNAM 1	239	0.00	34.76	93.2	99.07	8,949	Light Oil BBLS ->	0		0	0		
39			61,800.70					Gas MMCF ->	553,047	1,000,000	553,047	3,654,889	5.91	6.61
40	PUTNAM 2	239	0.00	30.66	96.7	99.19	8,970	Light Oil BBLS ->	0		0	0		

Date:
Company: Florida Power & Light — Schedule E4

Period: Aug-2011

Estimated For The Period of : 8/1/2011 Thru 8/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
41			54,526.20					Gas MMCF ->	489,111	1,000,000	489,111	3,232,315	5.93	6.61
42	MANATEE 1	788	32,329.00	9.19	95.5	71.23	10,865	Heavy Oil BBLS ->	56,894	6,400,042	364,124	4,698,424	14.53	82.58
43			21,552.70					Gas MMCF ->	221,287	1,000,000	221,287	1,463,714	6.79	6.61
44	MANATEE 2	788	61,912.00	17.60	95.7	73.57	10,829	Heavy Oil BBLS ->	108,363	6,400,026	693,526	8,948,938	14.45	82.58
45			41,274.70					Gas MMCF ->	423,868	1,000,000	423,868	2,803,848	6.79	6.61
46	MANATEE 3	1,058	730,378.00	92.79	95.9	92.79	6,861	Gas MMCF ->	5,011,190	1,000,000	5,011,190	33,000,794	4.52	6.59
47	MARTIN 1	802	44,634.00	24.02	95.1	80.85	10,586	Heavy Oil BBLS ->	66,665	6,400,045	426,659	5,578,878	12.50	83.69
48			98,674.40					Gas MMCF ->	1,090,388	1,000,000	1,090,388	7,190,827	7.29	6.59
49	MARTIN 2	802	53,882.00	29.60	94.8	84.72	10,395	Heavy Oil BBLS ->	79,784	6,400,018	510,619	6,676,680	12.39	83.68
50			122,766.80					Gas MMCF ->	1,325,589	1,000,000	1,325,589	8,744,244	7.12	6.60
51	MARTIN 3	431	148,275.00	46.24	96.2	96.64	7,319	Gas MMCF ->	1,085,256	1,000,000	1,085,256	6,944,062	4.68	6.40
52	MARTIN 4	431	165,927.00	51.74	95.1	95.77	7,219	Gas MMCF ->	1,197,826	1,000,000	1,197,826	7,699,620	4.64	6.43
53	MARTIN 8 (1)	1,052	714,073.20	91.23	94.7	94.41	6,884	Gas MMCF ->	4,916,014	1,000,000	4,916,014	31,983,916	4.48	6.51
54	FORT MYERS 1-12	552	615.00	0.15	98.4	22.28	28,579	Light Oil BBLS ->	3,015	5,829,519	17,576	306,700	49.87	101.72
55	LAUDERDALE 1-24	684	0.00	0.00	91.74			Light Oil BBLS ->	0		0	0		
56			0.00					Gas MMCF ->	0		0	0		
57	EVERGLADES 1-12	342	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0		
58			0.00					Gas MMCF ->	0		0	0		
59	ST JOHNS 10	124	90,425.00	95.77	95.8	98.01	9,892	Coal TONS ->	35,694	25,060,234	894,500	2,765,300	3.06	77.47
60	ST JOHNS 20	124	90,146.00	97.71	97.2	97.71	9,816	Coal TONS ->	35,310	25,060,096	884,872	2,735,600	3.03	77.47
61	SCHERER 4	626	455,368.00	95.55	95.6	97.77	10,272	Coal TONS ->	267,292	17,500,007	4,677,612	10,576,200	2.32	39.57
62	WCEC_01	1,219	816,253.00	90.00	90.0	90.00	6,893	Gas MMCF ->	5,626,156	1,000,000	5,626,156	36,596,751	4.48	6.50
63	WCEC_02	1,219	802,672.50	88.50	94.5	88.50	6,897	Gas MMCF ->	5,535,710	1,000,000	5,535,710	35,301,278	4.40	6.38
64	WCEC_03	1,219	788,499.70	86.94	95.4	86.94	6,901	Gas MMCF ->	5,441,088	1,000,000	5,441,088	34,697,933	4.40	6.38
65	DESOTO	25	4,929.00					SOLAR						
66	SPACE COAST	10	1,707.00					SOLAR						
67														
68	TOTAL	24,628	10,136,037.70				8,311	Gas MMCF ->	52,235,720		84,245,572	400,954,046	3.96	
69								Nuclear Othr ->	23,122,445					
70								Coal TONS ->	338,296					
71		PeriodHours -->		744				Heavy Oil BBLS ->	377,006					
								Light Oil BBLS ->	3,015					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modernization construction

Date:
Company: Florida Power & Light

Schedule E4

Period: Sep-2011

Estimated For The Period of : 9/1/2011 Thru 9/30/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	378	51,527.00	31.40	93.0	84.67	10,122	Heavy Oil BBLS ->	77,498	6,399,959	495,984	6,397,604	12.42	82.55
2			33,927.50					Gas MMCF ->	369,002	1,000,000	369,002	2,438,212	7.19	6.61
3	TURKEY POINT 2	378	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	693	486,491.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	3,854,800	0.79	0.70
6	TURKEY POINT 4	693	486,491.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	3,022,600	0.62	0.55
7	TURKEY POINT 5	1,053	691,484.80	91.21	96.7	91.21	6,907	Gas MMCF ->	4,776,103	1,000,000	4,776,103	31,065,433	4.49	6.50
8	LAUDERDALE 4	438	0.00	40.78	98.1	95.64	8,144	Light Oil BBLS ->	0		0	0		
9			128,605.60					Gas MMCF ->	1,047,328	1,000,000	1,047,328	6,933,843	5.39	6.62
10	LAUDERDALE 5	438	0.00	41.64	97.7	96.10	8,139	Light Oil BBLS ->	0		0	0		
11			131,329.20					Gas MMCF ->	1,068,847	1,000,000	1,068,847	7,076,444	5.39	6.62
12	PT EVERGLADES 1	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
17			0.00					Gas MMCF ->	0		0	0		
18	PT EVERGLADES 4	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
19			0.00					Gas MMCF ->	0		0	0		
20	RIVIERA 3 (2)	273	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	284	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	839	0.00	0.00	0.0			Nuclear Othr ->	0		0	0		
25	ST LUCIE 2	714	501,219.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	5,506,882	1,000,000	5,506,882	3,697,900	0.74	0.67
26	CAPE CANAVERAL 1 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	68	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	137	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,349	886,532.20	91.27	94.4	91.27	7,103	Gas MMCF ->	6,297,085	1,000,000	6,297,085	40,945,972	4.62	6.50
33	FORT MYERS 3A_B	296	0.00	46.49	93.5	97.88	14,270	Light Oil BBLS ->	0		0	0		
34			49,544.50					Gas MMCF ->	706,975	1,000,000	706,975	4,682,383	9.45	6.62
35	SANFORD 3	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	905	472,491.00	72.51	96.8	93.90	7,240	Gas MMCF ->	3,421,049	1,000,000	3,421,049	22,042,276	4.67	6.44
37	SANFORD 5	901	389,572.90	60.05	94.6	97.16	7,329	Gas MMCF ->	2,855,156	1,000,000	2,855,156	18,413,316	4.73	6.45
38	PUTNAM 1	239	0.00	39.72	93.2	99.30	8,923	Light Oil BBLS ->	0		0	0		
39			68,348.10					Gas MMCF ->	609,850	1,000,000	609,850	4,038,101	5.91	6.62
40	PUTNAM 2	239	0.00	39.04	96.7	99.32	8,944	Light Oil BBLS ->	0		0	0		

Date:
Company: Florida Power & Light

Schedule E4

Period: Sep-2011

Estimated For The Period of : 9/1/2011 Thru 9/30/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
41			67,175.30					Gas MMCF ->	600,828	1,000,000	600,828	3,978,313	5.92	6.62
42	MANATEE 1	788	45,247.00	13.29	95.5	78.44	10,795	Heavy Oil BBLS ->	78,679	6,399,992	503,545	6,521,798	14.41	82.89
43			30,164.40					Gas MMCF ->	310,482	1,000,000	310,482	2,057,526	6.82	6.63
44	MANATEE 2	788	70,302.00	20.65	95.7	79.09	10,743	Heavy Oil BBLS ->	121,354	6,399,979	776,663	10,059,319	14.31	82.89
45			46,868.00					Gas MMCF ->	482,064	1,000,000	482,064	3,194,493	6.82	6.63
46	MANATEE 3	1,058	705,602.40	92.63	95.9	92.63	6,864	Gas MMCF ->	4,843,068	1,000,000	4,843,068	31,946,956	4.53	6.60
47	MARTIN 1	802	50,825.00	28:02	95.1	83.02	10,536	Heavy Oil BBLS ->	75,964	6,400,018	486,171	6,396,261	12.58	84.20
48			110,960.00					Gas MMCF ->	1,218,473	1,000,000	1,218,473	8,051,616	7.26	6.61
49	MARTIN 2	802	57,831.00	32.84	94.8	84.15	10,416	Heavy Oil BBLS ->	85,616	6,399,984	547,941	7,209,027	12.47	84.20
50			131,822.70					Gas MMCF ->	1,427,457	1,000,000	1,427,457	9,432,621	7.16	6.61
51	MARTIN 3	431	12,495.00	4.03	6.4	96.64	7,280	Gas MMCF ->	90,964	1,000,000	90,964	583,225	4.67	6.41
52	MARTIN 4	431	184,146.20	59.34	95.1	95.37	7,207	Gas MMCF ->	1,327,068	1,000,000	1,327,068	8,546,053	4.64	6.44
53	MARTIN 8 (1)	1,052	711,626.10	93.95	94.7	93.95	6,890	Gas MMCF ->	4,903,122	1,000,000	4,903,122	32,023,875	4.50	6.53
54	FORT MYERS 1-12	552	11,544.00	2.90	98.4	65.35	15,695	Light Oil BBLS ->	31,074	5,830,051	181,163	3,185,500	27.59	102.51
55	LAUDERDALE 1-24	684	0.00	0.73	91.74	37.36	19,078	Light Oil BBLS ->	0		0	0		
56			3,578.20					Gas MMCF ->	68,263	1,000,000	68,263	450,289	12.58	6.60
57	EVERGLADES 1-12	342	0.00	0.25	88.3	88.74	17,735	Light Oil BBLS ->	0		0	0		
58			607.10					Gas MMCF ->	10,765	1,000,000	10,765	71,357	11.75	6.63
59	ST JOHNS 10	124	87,508.00	95.77	95.8	98.01	9,892	Coal TONS ->	34,543	25,059,925	865,645	2,676,100	3.06	77.47
60	ST JOHNS 20	124	87,238.00	97.71	97.2	97.71	9,816	Coal TONS ->	34,171	25,060,080	856,328	2,647,300	3.03	77.47
61	SCHERER 4	626	440,678.00	95.55	95.6	97.77	10,272	Coal TONS ->	258,670	17,499,985	4,526,721	10,240,700	2.32	39.59
62	WCEC_01	1,219	518,583.70	59.09	62.0	66.68	7,039	Gas MMCF ->	3,650,451	1,000,000	3,650,451	23,707,839	4.57	6.49
63	WCEC_02	1,219	780,832.30	88.97	94.5	88.97	6,902	Gas MMCF ->	5,389,470	1,000,000	5,389,470	34,433,905	4.41	6.39
64	WCEC_03	1,219	766,076.60	87.28	95.2	87.28	6,905	Gas MMCF ->	5,289,896	1,000,000	5,289,896	33,797,657	4.41	6.39
65	DESOTO	25	4,385.00					SOLAR						
66	SPACE COAST	10	1,511.00					SOLAR						
67														
68	TOTAL	24,628	9,305,170.80				8,225	Gas MMCF ->	50,763,765		76,535,596	395,820,616	4.25	
69								Nuclear Othr ->	16,531,670					
70								Coal TONS ->	327,384					
71		PeriodHours -->		720				Heavy Oil BBLS ->	439,111					
								Light Oil BBLS ->	31,074					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modernization construction

Date:
Company: Florida Power & Light

Schedule E4

Period: Oct-2011

Estimated For The Period of : 10/1/2011 Thru 10/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	378	34,804.00	22.27	93.0	74.29	10,259	Heavy Oil BBLS ->	52,665	6,399,981	337,055	4,350,148	12.50	82.60
2			27,813.90					Gas MMCF ->	305,323	1,000,000	305,323	2,056,157	7.39	6.73
3	TURKEY POINT 2	378	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	693	502,707.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,983,300	0.79	0.70
6	TURKEY POINT 4	693	502,707.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,123,400	0.62	0.55
7	TURKEY POINT 5	1,053	681,633.80	87.01	96.7	87.95	6,946	Gas MMCF ->	4,734,373	1,000,000	4,734,373	31,329,592	4.60	6.62
8	LAUDERDALE 4	438	0.00	37.06	98.1	92.83	8,165	Light Oil BBLS ->	0		0	0		
9			120,753.50					Gas MMCF ->	985,995	1,000,000	985,995	6,657,690	5.51	6.75
10	LAUDERDALE 5	438	0.00	42.91	97.7	92.28	8,147	Light Oil BBLS ->	0		0	0		
11			139,841.60					Gas MMCF ->	1,139,353	1,000,000	1,139,353	7,693,046	5.50	6.75
12	PT EVERGLADES 1	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	205	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
17			0.00					Gas MMCF ->	0		0	0		
18	PT EVERGLADES 4	374	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
19			0.00					Gas MMCF ->	0		0	0		
20	RIVIERA 3 (2)	273	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	284	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	839	0.00	0.00	0.0			Nuclear Othr ->	0		0	0		
25	ST LUCIE 2	714	517,926.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	3,821,100	0.74	0.67
26	CAPE CANAVERAL 1 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	68	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	137	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,349	876,520.20	87.33	94.4	90.37	7,121	Gas MMCF ->	6,241,447	1,000,000	6,241,447	41,466,550	4.73	6.64
33	FORT MYERS 3A_B	296	0.00	34.73	93.5	97.88	14,309	Light Oil BBLS ->	0		0	0		
34			38,244.90					Gas MMCF ->	547,226	1,000,000	547,226	3,696,942	9.67	6.76
35	SANFORD 3	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	905	465,186.10	69.09	96.8	94.49	7,259	Gas MMCF ->	3,376,846	1,000,000	3,376,846	22,293,259	4.79	6.60
37	SANFORD 5	901	364,795.80	54.42	96.2	97.80	7,351	Gas MMCF ->	2,681,591	1,000,000	2,681,591	17,653,995	4.84	6.58
38	PUTNAM 1	239	0.00	31.70	93.2	98.70	8,960	Light Oil BBLS ->	0		0	0		
39			56,376.90					Gas MMCF ->	505,131	1,000,000	505,131	3,411,715	6.05	6.75
40	PUTNAM 2	239	0.00	15.75	43.7	99.32	8,971	Light Oil BBLS ->	0		0	0		
41			28,009.40					Gas MMCF ->	251,267	1,000,000	251,267	1,697,014	6.06	6.75

Date:
Company: Florida Power & Light — Schedule E4

Period: Oct-2011

Estimated For The Period of : 10/1/2011 Thru 10/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
42	MANATEE 1	788	30,407.00	8.64	95.5	73.08	10,848	Heavy Oil BBLS ->	53,360	6,400,056	341,507	4,425,754	14.56	82.94
43			20,271.40					Gas MMCF ->	208,255	1,000,000	208,255	1,407,797	6.94	6.76
44	MANATEE 2	788	42,124.00	11.98	95.7	78.85	10,795	Heavy Oil BBLS ->	73,261	6,400,022	468,872	6,076,402	14.43	82.94
45			28,082.80					Gas MMCF ->	289,010	1,000,000	289,010	1,953,670	6.96	6.76
46	MANATEE 3	1,058	699,639.70	88.88	95.9	88.88	6,904	Gas MMCF ->	4,830,273	1,000,000	4,830,273	32,598,262	4.66	6.75
47	MARTIN 1	802	11,963.00	6.39	21.5	80.60	10,626	Heavy Oil BBLS ->	17,877	6,399,899	114,411	1,508,287	12.61	84.37
48			26,175.70					Gas MMCF ->	290,863	1,000,000	290,863	1,960,272	7.49	6.74
49	MARTIN 2	802	41,097.00	23.16	94.8	73.33	10,477	Heavy Oil BBLS ->	61,042	6,400,003	390,669	5,150,291	12.53	84.37
50			97,113.10					Gas MMCF ->	1,057,320	1,000,000	1,057,320	7,121,156	7.33	6.74
51	MARTIN 3	431	117,003.00	36.49	74.4	96.61	7,316	Gas MMCF ->	856,024	1,000,000	856,024	5,601,928	4.79	6.54
52	MARTIN 4	431	190,424.90	59.38	95.1	95.63	7,208	Gas MMCF ->	1,372,667	1,000,000	1,372,667	9,086,024	4.77	6.62
53	MARTIN 8 (1)	1,052	674,810.10	86.22	92.4	89.46	6,936	Gas MMCF ->	4,680,214	1,000,000	4,680,214	31,274,828	4.63	6.68
54	FORT MYERS 1-12	552	746.00	0.18	98.4	16.89	35,066	Light Oil BBLS ->	4,487	5,829,953	26,159	463,600	62.14	103.32
55	LAUDERDALE 1-24	684	0.00	0.00	91.74			Light Oil BBLS ->	0		0	0		
56			0.00					Gas MMCF ->	0		0	0		
57	EVERGLADES 1-12	342	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0		
58			0.00					Gas MMCF ->	0		0	0		
59	ST JOHNS 10	124	84,715.00	91.83	95.8	91.83	9,933	Coal TONS ->	33,579	25,059,918	841,487	2,601,400	3.07	77.47
60	ST JOHNS 20	124	88,620.00	96.06	97.2	96.06	9,827	Coal TONS ->	34,752	25,059,795	870,878	2,692,300	3.04	77.47
61	SCHERER 4	626	454,939.00	95.55	95.6	97.68	10,272	Coal TONS ->	267,043	17,500,021	4,673,258	10,578,000	2.33	39.61
62	WCEC_01	1,219	507,436.40	55.95	59.0	60.24	7,144	Gas MMCF ->	3,625,345	1,000,000	3,625,345	23,997,084	4.73	6.62
63	WCEC_02	1,219	768,783.50	84.77	94.5	84.77	6,946	Gas MMCF ->	5,340,125	1,000,000	5,340,125	34,834,487	4.53	6.52
64	WCEC_03	1,219	753,354.70	83.07	95.4	83.07	6,952	Gas MMCF ->	5,237,651	1,000,000	5,237,651	34,166,004	4.54	6.52
65	DESOTO	25	4,232.00					SOLAR						
66	SPACE COAST	10	1,457.00					SOLAR						
67														
68	TOTAL	24,628	9,000,715.40				8,169	Gas MMCF ->	48,556,298		73,703,327	370,731,454	4.12	
69								Nuclear Othr ->	17,082,733					
70								Coal TONS ->	335,374					
71		PeriodHours -->		744				Heavy Oil BBLS ->	258,205					
								Light Oil BBLS ->	4,487					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modernization construction

Date:
Company: Florida Power & Light

Schedule E4

Period: Nov-2011

Estimated For The Period of : 11/1/2011 Thru 11/30/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	380	844.00	0.57	93.0	51.25	10,625	Heavy Oil BBLS ->	1,295	6,399,228	8,287	107,700	12.76	83.17
2			714.60					Gas MMCF ->	8,267	1,000,000	8,267	58,094	8.13	7.03
3	TURKEY POINT 2	380	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	717	503,332.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,703,297	1,000,000	5,703,297	3,988,300	0.79	0.70
6	TURKEY POINT 4	717	503,332.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,703,297	1,000,000	5,703,297	3,127,300	0.62	0.55
7	TURKEY POINT 5	1,114	504,319.90	62.88	87.0	87.73	6,956	Gas MMCF ->	3,507,843	1,000,000	3,507,843	24,393,307	4.84	6.95
8	LAUDERDALE 4	447	0.00	5.33	98.1	95.87	8,176	Light Oil BBLS ->	0		0	0		
9			17,141.60					Gas MMCF ->	140,150	1,000,000	140,150	989,283	5.77	7.06
10	LAUDERDALE 5	447	0.00	6.75	97.7	95.31	8,164	Light Oil BBLS ->	0		0	0		
11			21,727.90					Gas MMCF ->	177,379	1,000,000	177,379	1,252,193	5.76	7.06
12	PT EVERGLADES 1	207	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	207	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	376	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
17			0.00					Gas MMCF ->	0		0	0		
18	PT EVERGLADES 4	376	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
19			0.00					Gas MMCF ->	0		0	0		
20	RIVIERA 3 (2)	275	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	286	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	853	0.00	0.00	0.0			Nuclear Othr ->	0		0	0		
25	ST LUCIE 2	714	501,219.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	5,506,882	1,000,000	5,506,882	3,697,900	0.74	0.67
26	CAPE CANAVERAL 1 (2)	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	69	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,440	642,255.90	61.95	94.4	92.92	7,103	Gas MMCF ->	4,562,233	1,000,000	4,562,233	31,819,919	4.95	6.97
33	FORT MYERS 3A_B	328	139.00	3.94	93.5	97.88	13,766	Light Oil BBLS ->	307	5,830,619	1,790	32,000	23.02	104.23
34			4,515.90					Gas MMCF ->	62,293	1,000,000	62,293	439,842	9.74	7.06
35	SANFORD 3	140	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	955	303,786.50	44.18	96.8	95.24	7,325	Gas MMCF ->	2,225,204	1,000,000	2,225,204	15,418,752	5.08	6.93
37	SANFORD 5	952	255,151.40	37.22	96.2	93.39	7,375	Gas MMCF ->	1,881,660	1,000,000	1,881,660	13,036,280	5.11	6.93
38	PUTNAM 1	248	0.00	5.24	93.2	99.29	8,890	Light Oil BBLS ->	0		0	0		
39			9,357.70					Gas MMCF ->	83,188	1,000,000	83,188	587,330	6.28	7.06
40	PUTNAM 2	248	0.00	0.00	0.0			Light Oil BBLS ->	0		0	0		
41			0.00					Gas MMCF ->	0		0	0		
42	MANATEE 1	798	0.00	0.00	95.5			Heavy Oil BBLS ->	0		0	0		
43			0.00					Gas MMCF ->	0		0	0		

Date:
Company: Florida Power & Light

Schedule E4

Period: Nov-2011

Estimated For The Period of : 11/1/2011 Thru 11/30/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
44	MANATEE 2	798	0.00	0.00	19.1			Heavy Oil BBLS ->	0		0	0		
45			0.00					Gas MMCF ->	0		0	0		
46	MANATEE 3	1,117	684,323.90	85.09	95.9	87.65	6,861	Gas MMCF ->	4,695,062	1,000,000	4,695,062	32,811,365	4.79	6.99
47	MARTIN 1	808	0.00	0.00	76.1			Heavy Oil BBLS ->	0		0	0		
48			0.00					Gas MMCF ->	0		0	0		
49	MARTIN 2	808	909.00	0.56	94.8	50.15	11,107	Heavy Oil BBLS ->	1,354	6,399,557	8,665	115,900	12.75	85.60
50			2,332.70					Gas MMCF ->	27,344	1,000,000	27,344	192,265	8.24	7.03
51	MARTIN 3	462	124,513.30	37.43	96.2	94.56	7,300	Gas MMCF ->	908,923	1,000,000	908,923	6,286,557	5.05	6.92
52	MARTIN 4	462	132,996.20	39.98	95.1	95.96	7,222	Gas MMCF ->	960,548	1,000,000	960,548	6,664,012	5.01	6.94
53	MARTIN 8 (1)	1,112	447,753.90	55.92	68.7	70.89	7,029	Gas MMCF ->	3,147,041	1,000,000	3,147,041	21,940,484	4.90	6.97
54	FORT MYERS 1-12	627	0.00	0.00	98.4			Light Oil BBLS ->	0		0	0		
55	LAUDERDALE 1-24	766	0.00	0.00	91.74			Light Oil BBLS ->	0		.0	0		
56			0.00					Gas MMCF ->	0		0	0		
57	EVERGLADES 1-12	383	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0		
58			0.00					Gas MMCF ->	0		0	0		
59	ST JOHNS 1O	124	86,779.00	95.77	95.8	97.20	9,797	Coal TONS ->	33,925	25,059,838	850,155	2,628,200	3.03	77.47
60	ST JOHNS 2O	124	86,953.00	97.24	97.2	97.39	9,716	Coal TONS ->	33,713	25,060,184	844,854	2,611,900	3.00	77.47
61	SCHERER 4	632	444,377.00	95.55	95.6	97.66	10,200	Coal TONS ->	259,005	17,500,021	4,532,593	10,265,300	2.31	39.63
62	WCEC_01	1,335	782,244.60	81.38	90.0	81.38	6,858	Gas MMCF ->	5,364,284	1,000,000	5,364,284	37,106,750	4.74	6.92
63	WCEC_02	1,335	746,419.60	77.65	94.5	77.65	6,849	Gas MMCF ->	5,112,448	1,000,000	5,112,448	35,100,438	4.70	6.87
64	WCEC_03	1,335	721,882.50	75.10	95.2	75.10	6,858	Gas MMCF ->	4,950,759	1,000,000	4,950,759	33,990,310	4.71	6.87
65	DESOTO	25	3,620.00					SOLAR						
66	SPACE COAST	10	1,245.00					SOLAR						
67														
68	TOTAL	25,800	7,534,187.10				8,093	Gas MMCF ->	37,814,626		60,974,446	288,661,681	3.83	
69		=======	=======				=======	Nuclear Othr ->	16,913,476		=======	=======	=======	
70								Coal TONS ->	326,643					
71		PeriodHours -->		720				Heavy Oil BBLS ->	2,649					
								Light Oil BBLS ->	307					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modernization construction

Date:
Company: Florida Power & Light

Period: Dec-2011

Schedule E4

Estimated For The Period of : 12/1/2011 Thru 12/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
1	TURKEY POINT 1	380	0.00	0.00	93.0			Heavy Oil BBLS ->	0		0	0		
2			0.00					Gas MMCF ->	0		0	0		
3	TURKEY POINT 2	380	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
4			0.00					Gas MMCF ->	0		0	0		
5	TURKEY POINT 3	717	520,110.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	4,121,200	0.79	0.70
6	TURKEY POINT 4	717	520,110.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	3,231,500	0.62	0.55
7	TURKEY POINT 5	1,114	414,377.20	50.00	84.2	84.73	6,992	Gas MMCF ->	2,897,359	1,000,000	2,897,359	21,041,123	5.08	7.26
8	LAUDERDALE 4	447	0.00	5.73	98.1	77.49	8,328	Light Oil BBLS ->	0		0	0		
9			19,051.40					Gas MMCF ->	158,649	1,000,000	158,649	1,166,604	6.12	7.35
10	LAUDERDALE 5	447	0.00	9.09	97.7	76.85	8,309	Light Oil BBLS ->	0		0	0		
11			30,231.20					Gas MMCF ->	251,181	1,000,000	251,181	1,846,773	6.11	7.35
12	PT EVERGLADES 1	207	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
13			0.00					Gas MMCF ->	0		0	0		
14	PT EVERGLADES 2	207	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
15			0.00					Gas MMCF ->	0		0	0		
16	PT EVERGLADES 3	376	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
17			0.00					Gas MMCF ->	0		0	0		
18	PT EVERGLADES 4	376	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0		
19			0.00					Gas MMCF ->	0		0	0		
20	RIVIERA 3 (2)	275	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
21			0.00					Gas MMCF ->	0		0	0		
22	RIVIERA 4 (2)	286	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
23			0.00					Gas MMCF ->	0		0	0		
24	ST LUCIE 1	975	342,224.00	47.18	47.2	97.50	10,987	Nuclear Othr ->	3,760,031	1,000,000	3,760,031	2,169,800	0.63	0.58
25	ST LUCIE 2	726	526,572.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	5,785,382	1,000,000	5,785,382	3,884,900	0.74	0.67
26	CAPE CANAVERAL 1 (2)	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
27			0.00					Gas MMCF ->	0		0	0		
28	CAPE CANAVERAL 2 (2)	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0		
29			0.00					Gas MMCF ->	0		0	0		
30	CUTLER 5	69	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
31	CUTLER 6	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
32	FORT MYERS 2	1,440	572,422.70	53.43	94.4	88.53	7,133	Gas MMCF ->	4,082,980	1,000,000	4,082,980	29,690,287	5.19	7.27
33	FORT MYERS 3A_B	328	0.00	0.00	93.5			Light Oil BBLS ->	0		0	0		
34			0.00					Gas MMCF ->	0		0	0		
35	SANFORD 3	140	0.00	0.00	100.0			Gas MMCF ->	0		0	0		
36	SANFORD 4	955	260,981.20	36.73	96.8	89.89	7,325	Gas MMCF ->	1,911,683	1,000,000	1,911,683	13,821,576	5.30	7.23
37	SANFORD 5	952	190,172.80	26.85	96.2	90.39	7,392	Gas MMCF ->	1,405,733	1,000,000	1,405,733	10,162,968	5.34	7.23
38	PUTNAM 1	248	0.00	7.97	93.2	70.56	9,496	Light Oil BBLS ->	0		0	0		
39			14,699.70					Gas MMCF ->	139,581	1,000,000	139,581	1,020,734	6.94	7.31
40	PUTNAM 2	248	0.00	0.00	46.8			Light Oil BBLS ->	0		0	0		
41			0.00					Gas MMCF ->	0		0	0		
42	MANATEE 1	798	0.00	0.00	95.5			Heavy Oil BBLS ->	0		0	0		
43			0.00					Gas MMCF ->	0		0	0		

Date:
Company: Florida Power & Light

Schedule E4

Period: Dec-2011

Estimated For The Period of : 12/1/2011 Thru 12/31/2011

	(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 ($)	(M) Fuel Cost per KWH (C/KWH)	(N) Cost of Fuel ($/Unit)
44	MANATEE 2	798	0.00	0.00	71.0			Heavy Oil BBLS ->	0		0	0		
45			0.00					Gas MMCF ->	0		0	0		
46	MANATEE 3	1,117	552,280.50	66.46	95.9	87.51	6,887	Gas MMCF ->	3,803,340	1,000,000	3,803,340	27,695,856	5.01	7.28
47	MARTIN 1	808	0.00	0.00	95.1			Heavy Oil BBLS ->	0		0	0		
48			0.00					Gas MMCF ->	0		0	0		
49	MARTIN 2	808	0.00	0.00	94.8			Heavy Oil BBLS ->	0		0	0		
50			0.00					Gas MMCF ->	0		0	0		
51	MARTIN 3	462	115,452.00	33.59	96.2	88.61	7,319	Gas MMCF ->	845,040	1,000,000	845,040	6,107,653	5.29	7.23
52	MARTIN 4	462	130,300.10	37.91	95.1	89.25	7,250	Gas MMCF ->	944,677	1,000,000	944,677	6,843,248	5.25	7.24
53	MARTIN 8 (1)	1,112	321,750.70	38.89	62.6	64.44	7,171	Gas MMCF ->	2,307,363	1,000,000	2,307,363	16,785,584	5.22	7.27
54	FORT MYERS 1-12	627	0.00	0.00	98.4			Light Oil BBLS ->	0		0	0		
55	LAUDERDALE 1-24	766	0.00	0.00	91.74			Light Oil BBLS ->	0		0	0		
56			0.00					Gas MMCF ->	0		0	0		
57	EVERGLADES 1-12	383	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0		
58			0.00					Gas MMCF ->	0		0	0		
59	ST JOHNS 10	124	89,430.00	95.77	95.8	96.94	9,800	Coal TONS ->	34,971	25,060,164	876,379	2,709,300	3.03	77.47
60	ST JOHNS 20	124	89,579.00	97.10	97.2	97.10	9,719	Coal TONS ->	34,739	25,060,307	870,570	2,691,400	3.00	77.47
61	SCHERER 4	632	458,803.00	95.55	95.6	97.57	10,200	Coal TONS ->	267,422	17,500,000	4,679,885	10,604,700	2.31	39.66
62	WCEC_01	1,335	791,504.00	79.69	90.0	79.69	6,843	Gas MMCF ->	5,416,033	1,000,000	5,416,033	38,976,242	4.92	7.20
63	WCEC_02	1,335	760,718.40	76.59	94.5	76.59	6,840	Gas MMCF ->	5,203,462	1,000,000	5,203,462	37,301,964	4.90	7.17
64	WCEC_03	1,335	715,005.60	71.99	95.4	74.70	6,848	Gas MMCF ->	4,896,338	1,000,000	4,896,338	35,100,325	4.91	7.17
65	DESOTO	25	3,287.00					SOLAR						
66	SPACE COAST	10	1,101.00					SOLAR						
67														
68	TOTAL	25,934	7,440,163.50				8,336	Gas MMCF ->	34,263,417		62,022,484	276,973,737	3.72	
69								Nuclear Othr ->	21,332,233					
70								Coal TONS ->	337,132					
71		PeriodHours -->		744				Heavy Oil BBLS ->	0					
								Light Oil BBLS ->	0					

(1) - Generation includes the Martin solar thermal facility, which is designed to provide steam for Martin Unit 8 thus reducing natural gas use. No additional capacity will result from the operation of the solar thermal facility.

(2) Unit unavailable due to modernization construction

Company: Florida Power & Light

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2011 thru June 2011

			January 2011	February 2011	March 2011	April 2011	May 2011	June 2011
	Heavy Oil							
1	Purchases:							
2	Units	(BBLS)	133,025	50,983	23,818	130,675	483,157	1,138,003
3	Unit Cost	($/BBLS)	80.6540	81.0662	81.0731	81.7907	81.7540	82.4787
4	Amount	($)	10,729,000	4,133,000	1,931,000	10,688,000	39,500,000	93,861,000
5								
6	Burned:							
7	Units	(BBLS)	133,025	50,983	23,818	130,675	283,157	268,003
8	Unit Cost	($/BBLS)	80.8259	81.0662	81.0731	81.7907	81.3893	81.7518
9	Amount	($)	10,751,870	4,133,000	1,931,000	10,688,000	23,045,936	21,909,728
10								
11	Ending Inventory:							
12	Units	(BBLS)	1,735,000	1,735,000	1,735,000	1,735,000	1,935,000	2,805,000
13	Unit Cost	($/BBLS)	80.0582	80.0582	80.0582	80.0582	80.2424	80.9351
14	Amount	($)	138,901,000	138,901,000	138,901,000	138,901,000	155,269,000	227,023,000
15								
16	Light Oil							
17								
18								
19	Purchases:							
20	Units	(BBLS)	57,389	3,156	133,177	5,853	1,030	0
21	Unit Cost	($/BBLS)	97.9456	100.4436	101.4515	100.6322	100.9709	0.0000
22	Amount	($)	5,621,000	317,000	13,511,000	589,000	104,000	0
23								
24	Burned:							
25	Units	(BBLS)	57,089	3,156	1,177	5,853	1,030	0
26	Unit Cost	($/BBLS)	97.9173	100.4436	101.1045	100.6322	100.9709	0.0000
27	Amount	($)	5,590,000	317,000	119,000	589,000	104,000	0
28								
29	Ending Inventory:							
30	Units	(BBLS)	822,088	822,088	954,088	954,088	954,088	954,088
31	Unit Cost	($/BBLS)	98.2839	98.2839	98.7225	98.7225	98.7225	98.7225
32	Amount	($)	80,798,000	80,798,000	94,190,000	94,190,000	94,190,000	94,190,000
33								
34	Coal - SJRPP							
35								
36								
37	Purchases:							
38	Units	(Tons)	69,558	59,451	36,104	61,694	64,662	67,922
39	Unit Cost	($/Tons)	79.5739	79.5781	82.7332	79.5701	79.5676	77.4712
40	Amount	($)	5,535,000	4,731,000	2,987,000	4,909,000	5,145,000	5,262,000
41								
42	Burned:							
43	Units	(Tons)	69,558	59,451	36,104	61,694	64,662	67,922
44	Unit Cost	($/Tons)	79.5739	79.5781	82.7332	79.5701	79.5676	77.4712
45	Amount	($)	5,535,000	4,731,000	2,987,000	4,909,000	5,145,000	5,262,000
46								
47	Ending Inventory:							
48	Units	(Tons)	90,999	91,000	91,000	91,000	91,000	90,999
49	Unit Cost	($/Tons)	73.3305	73.3297	73.3297	73.3297	73.3297	73.3305
50	Amount	($)	6,673,000	6,673,000	6,673,000	6,673,000	6,673,000	6,673,000
51								
52	Coal - SCHERER							
53								
54								
55	Purchases:							
56	Units	(MBTU)	4,689,090	4,221,768	4,685,293	4,518,290	4,677,610	905,345
57	Unit Cost	($/MBTU)	2.2522	2.2535	2.2547	2.2559	2.2573	2.2588
58	Amount	($)	10,561,000	9,514,000	10,564,000	10,193,000	10,559,000	2,045,000
59								
60	Burned:							
61	Units	(MBTU)	4,689,090	4,221,770	4,685,310	4,518,273	4,677,610	905,345
62	Unit Cost	($/MBTU)	2.2522	2.2536	2.2547	2.2560	2.2573	2.2588
63	Amount	($)	10,561,000	9,514,000	10,564,000	10,193,000	10,559,000	2,045,000
64								
65	Ending Inventory:							
66	Units	(MBTU)	5,035,413	5,035,412	5,035,413	5,035,409	5,035,408	5,035,414
67	Unit Cost	($/MBTU)	2.1965	2.1965	2.1965	2.1965	2.1965	2.1965
68	Amount	($)	11,060,229	11,060,229	11,060,229	11,060,229	11,060,229	11,060,229
69								
70	Gas							
71								
72								
73	Burned:							
74	Units	(MCF)	36,251,088	33,195,204	39,044,460	38,878,653	44,239,886	46,949,651
75	Unit Cost	($/MCF)	6.5696	6.5423	6.4365	6.6945	6.5874	6.5004
76	Amount	($)	238,156,760	217,171,868	251,309,213	260,274,907	291,426,069	305,190,762
77								
78	Nuclear							
79								
80								
81	Burned:							
82	Units	(MBTU)	18,958,497	16,788,650	17,233,553	17,490,402	21,564,585	23,002,796
83	Unit Cost	($/MBTU)	0.6262	0.6298	0.6357	0.6498	0.6333	0.6255
84	Amount	($)	11,871,000	10,572,000	10,956,000	11,365,000	13,657,000	14,388,000

Company: Florida Power & Light

Schedule: E5
Page : 2

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : July 2011 thru December 2011

Line	Item	Unit	July 2011	August 2011	September 2011	October 2011	November 2011	December 2011	Total
	Heavy Oil								
1	Purchases:								
2	Units	(BBLS)	291,075	377,007	77,531	52,665	1,295	0	2,759,234
3	Unit Cost	($/BBLS)	82.9649	83.3565	82.9862	83.3191	83.3977	0.0000	82.3950
4	Amount	($)	24,149,000	31,426,000	6,434,000	4,388,000	108,000	0	227,347,000
5									
6	Burned:								
7	Units	(BBLS)	291,075	377,007	439,110	258,206	2,649	0	2,257,708
8	Unit Cost	($/BBLS)	82.6993	82.9527	83.3138	83.3109	84.5602	0.0000	82.4395
9	Amount	($)	24,071,705	31,273,748	36,583,910	21,511,382	224,000	0	186,124,279
10									
11	Ending Inventory:								
12	Units	(BBLS)	2,805,000	2,805,000	2,443,420	2,237,880	2,236,526	2,236,526	2,236,526
13	Unit Cost	($/BBLS)	80.9351	80.9351	80.4958	80.1553	80.1520	80.1520	80.1520
14	Amount	($)	227,023,000	227,023,000	196,685,000	179,378,000	179,262,000	179,262,000	179,262,000
15									
16	Light Oil								
17									
18									
19	Purchases:								
20	Units	(BBLS)	1,030	3,015	31,074	4,487	307	242,000	482,518
21	Unit Cost	($/BBLS)	100.9709	101.8242	102.5294	103.4099	104.2345	103.6281	102.1993
22	Amount	($)	104,000	307,000	3,186,000	464,000	32,000	25,078,000	49,313,000
23									
24	Burned:								
25	Units	(BBLS)	1,030	3,015	31,074	4,487	307	0	108,218
26	Unit Cost	($/BBLS)	100.9709	101.8242	102.5294	103.4099	104.2345	0.0000	99.9094
27	Amount	($)	104,000	307,000	3,186,000	464,000	32,000	0	10,812,000
28									
29	Ending Inventory:								
30	Units	(BBLS)	954,088	954,088	954,088	954,088	954,088	1,196,088	1,196,088
31	Unit Cost	($/BBLS)	98.7225	98.7225	98.7225	98.7225	98.7225	99.7159	99.7159
32	Amount	($)	94,190,000	94,190,000	94,190,000	94,190,000	94,190,000	119,269,000	119,269,000
33									
34	Coal - SJRPP								
35									
36									
37	Purchases:								
38	Units	(Tons)	64,447	71,004	68,714	68,330	67,637	69,709	769,232
39	Unit Cost	($/Tons)	82.7191	77.4745	77.4660	77.4770	77.4724	77.4792	78.8566
40	Amount	($)	5,331,000	5,501,000	5,323,000	5,294,000	5,240,000	5,401,000	60,659,000
41									
42	Burned:								
43	Units	(Tons)	64,447	71,004	68,714	68,330	67,637	69,709	769,232
44	Unit Cost	($/Tons)	82.7191	77.4745	77.4660	77.4770	77.4724	77.4792	78.8566
45	Amount	($)	5,331,000	5,501,000	5,323,000	5,294,000	5,240,000	5,401,000	60,659,000
46									
47	Ending Inventory:								
48	Units	(Tons)	91,000	90,999	90,999	90,999	90,999	90,999	90,999
49	Unit Cost	($/Tons)	73.3297	73.3305	73.3305	73.3305	73.3305	73.3305	73.3305
50	Amount	($)	6,673,000	6,673,000	6,673,000	6,673,000	6,673,000	6,673,000	6,673,000
51									
52	Coal - SCHERER								
53									
54									
55	Purchases:								
56	Units	(MBTU)	2,716,035	4,677,610	4,526,725	4,673,253	4,532,588	4,679,885	49,503,510
57	Unit Cost	($/MBTU)	2.2599	2.2610	2.2623	2.2635	2.2647	2.2661	2.2592
58	Amount	($)	6,138,000	10,576,000	10,241,000	10,578,000	10,265,000	10,605,000	111,839,000
59									
60	Burned:								
61	Units	(MBTU)	2,716,035	4,677,610	4,526,725	4,673,253	4,532,588	4,679,885	49,503,493
62	Unit Cost	($/MBTU)	2.2599	2.2610	2.2623	2.2635	2.2647	2.2661	2.2592
63	Amount	($)	6,138,000	10,576,000	10,241,000	10,578,000	10,265,000	10,605,000	111,839,000
64									
65	Ending Inventory:								
66	Units	(MBTU)	5,035,411	5,035,408	5,035,408	5,035,409	5,035,413	5,035,413	60,424,931
67	Unit Cost	($/MBTU)	2.1965	2.1965	2.1965	2.1965	2.1965	2.1965	2.1965
68	Amount	($)	11,060,229	11,060,229	11,060,229	11,060,229	11,060,229	11,060,229	132,722,743
69									
70	Gas								
71									
72									
73	Burned:								
74	Units	(MCF)	52,255,767	52,235,720	50,763,765	48,556,298	37,814,626	34,263,417	514,448,533
75	Unit Cost	($/MCF)	6.4548	6.4862	6.4990	6.6306	6.9308	7.2252	6.6113
76	Amount	($)	337,302,680	338,811,298	329,911,706	321,957,472	262,087,181	247,560,937	3,401,160,849
77									
78	Nuclear								
79									
80									
81	Burned:								
82	Units	(MBTU)	23,769,566	23,122,445	16,531,670	17,082,733	16,913,476	21,332,233	233,788,606
83	Unit Cost	($/MBTU)	0.6254	0.6264	0.6397	0.6397	0.6393	0.6285	0.6326
84	Amount	($)	14,866,000	14,485,000	10,576,000	10,927,000	10,813,000	13,408,000	147,884,000

Schedule: E6

Company: Florida Power & Light

POWER SOLD

Estimated for the Period of : January 2011 thru December 2011

(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)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
January		OS	148,500		148,500	4.342	5.851	6,448,440	8,688,685	1,823,390
2011	St.Lucie Rel.		46,084		46,084	0.647	0.647	298,229	298,229	0
Total			194,584	0	194,584	3.467	4.619	6,746,669	8,986,914	1,823,390
February		OS	171,000		171,000	4.644	6.040	7,940,890	10,328,165	1,923,974
2011	St.Lucie Rel.		41,625		41,625	0.647	0.647	269,368	269,368	0
Total			212,625	0	212,625	3.861	4.984	8,210,258	10,597,533	1,923,974
March		OS	115,000		115,000	4.115	5.391	4,732,435	6,200,185	1,132,972
2011	St.Lucie Rel.		46,084		46,084	0.647	0.647	298,229	298,229	0
Total			161,084	0	161,084	3.123	4.034	5,030,664	6,498,414	1,132,972
April		OS	39,500		39,500	5.336	6.578	2,107,580	2,598,330	365,649
2011	St.Lucie Rel.		43,866		43,866	0.647	0.647	283,871	283,871	0
Total			83,366	0	83,366	2.869	3.457	2,391,451	2,882,201	365,649
May		OS	22,500		22,500	5.692	7.046	1,280,700	1,585,260	233,823
2011	St.Lucie Rel.		45,332		45,332	0.647	0.647	293,333	293,333	0
Total			67,832	0	67,832	2.320	2.769	1,574,033	1,878,593	233,823
June		OS	23,000		23,000	5.980	7.402	1,375,310	1,702,560	256,730
2011	St.Lucie Rel.		43,866		43,866	0.647	0.647	283,871	283,871	0
Total			66,866	0	66,866	2.481	2.971	1,659,181	1,986,431	256,730

Schedule: E6

Company: Florida Power & Light

POWER SOLD

Estimated for the Period of : January 2011 thru December 2011

(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)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
July		OS	36,000		36,000	5.538	6.717	1,993,680	2,418,100	332,757
2011	St.Lucie Rel.		45,332		45,332	0.647	0.647	293,333	293,333	0
Total			81,332	0	81,332	2.812	3.334	2,287,013	2,711,433	332,757
August		OS	42,000		42,000	6.090	7.556	2,557,980	3,173,600	483,027
2011	St.Lucie Rel.		40,941		40,941	0.647	0.647	264,946	264,946	0
Total			82,941	0	82,941	3.404	4.146	2,822,926	3,438,546	483,027
September		OS	20,000		20,000	6.451	7.467	1,290,210	1,493,320	160,097
2011	St.Lucie Rel.		0		0	0.000	0.000	0	0	0
Total			20,000	0	20,000	6.451	7.467	1,290,210	1,493,320	160,097
October		OS	36,000		36,000	6.205	7.364	2,233,840	2,650,960	329,025
2011	St.Lucie Rel.		0		0	0.000	0.000	0	0	0
Total			36,000	0	36,000	6.205	7.364	2,233,840	2,650,960	329,025
November		OS	82,000		82,000	3.729	5.119	3,057,590	4,197,950	955,689
2011	St.Lucie Rel.		0		0	0.000	0.000	0	0	0
Total			82,000	0	82,000	3.729	5.119	3,057,590	4,197,950	955,689
December		OS	138,000		138,000	3.778	5.289	5,213,380	7,299,020	1,695,572
2011	St.Lucie Rel.		25,488		25,488	0.634	0.634	161,582	161,582	0
Total			163,488	0	163,488	3.288	4.563	5,374,962	7,460,602	1,695,572
Period		OS	873,500	0	873,500	4.606	5.992	40,232,035	52,336,135	9,692,706
	St.Lucie Rel.		378,619	0	378,619	0.646	0.646	2,446,761	2,446,761	0
Total			1,252,119	0	1,252,119	3.409	4.375	42,678,796	54,782,896	9,692,706

APPENDIX II

Company: Florida Power & Light

Schedule: E7
Page : 1

Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2011 thru December 2011

(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)
2011	UPS		213,679			213,679	4.060		8,676,128
January	St. Lucie Rel.		2,530			2,530	0.486		12,300
	SJRPP		265,904			265,904	3.100		8,243,000
	PPAs		823			823	8.656		71,260
Total			482,936			482,936	3.520		17,001,688
2011	UPS		201,198			201,198	4.170		8,389,740
February	St. Lucie Rel.		0			0	0.000		0
	SJRPP		228,556			228,556	3.099		7,082,000
	PPAs		412			412	8.624		35,530
Total			430,166			430,166	3.605		15,507,270
2011	UPS		191,732			191,732	3.954		7,580,521
March	St. Lucie Rel.		7,591			7,591	0.738		56,000
	SJRPP		138,410			138,410	3.222		4,459,000
	PPAs								
Total			337,733			337,733	3.581		12,095,521
2011	UPS		296,827			296,827	4.145		12,303,698
April	St. Lucie Rel.		37,333			37,333	0.737		275,200
	SJRPP		232,805			232,805	3.152		7,337,000
	PPAs		1,852			1,852	7.998		148,121
Total			568,817			568,817	3.527		20,064,019
	UPS		350,539			350,539	4.175		14,635,663
2011	St. Lucie Rel.		38,577			38,577	0.737		284,400
May	SJRPP		244,821			244,821	3.148		7,706,000
	PPAs		823			823	8.221		67,660
Total			634,760			634,760	3.575		22,693,723
	UPS		297,157			297,157	4.183		12,430,811
2011	St. Lucie Rel.		37,333			37,333	0.737		275,200
June	SJRPP		257,930			257,930	3.049		7,863,000
	PPAs		412			412	8.357		34,430
Total			592,832			592,832	3.475		20,603,441
	UPS		1,551,132			1,551,132	4.127		64,015,562
Period	St. Lucie Rel.		123,364			123,364	0.732		903,100
Total	SJRPP		1,368,426			1,368,426	3.120		42,690,000
	PPAs		4,322			4,322	8.260		357,001
Total			3,047,244			3,047,244	3.543		107,965,664

Company: Florida Power & Light

Schedule: E7
Page : 2

Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2011 thru December 2011

(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)
2011	UPS		325,250			325,250	4.207		13,684,152
July	St. Lucie Rel.		38,577			38,577	0.737		284,400
	SJRPP		243,398			243,398	3.273		7,967,000
	PPAs		412			412	8.430		34,730
Total			607,637			607,637	3.616		21,970,282
2011	UPS		302,364			302,364	4.217		12,751,482
August	St. Lucie Rel.		38,577			38,577	0.737		284,400
	SJRPP		270,858			270,858	3.046		8,251,000
	PPAs		1,235			1,235	8.477		104,690
Total			613,034			613,034	3.489		21,391,572
2011	UPS		337,097			337,097	4.281		14,430,467
September	St. Lucie Rel.		37,333			37,333	0.301		112,500
	SJRPP		262,115			262,115	3.046		7,984,000
	PPAs		5,170			5,170	7.952		411,101
Total			641,715			641,715	3.574		22,938,069
2011	UPS		322,673			322,673	4.267		13,768,744
October	St. Lucie Rel.		38,577			38,577	0.301		116,300
	SJRPP		259,477			259,477	3.054		7,925,000
	PPAs		2,058			2,058	8.588		176,751
Total			622,785			622,785	3.530		21,986,795
	UPS		137,350			137,350	3.743		5,141,026
2011	St. Lucie Rel.		37,333			37,333	0.301		112,500
November	SJRPP		259,976			259,976	3.016		7,841,000
	PPAs								
Total			434,659			434,659	3.013		13,094,526
	UPS		130,330			130,330	3.629		4,730,164
2011	St. Lucie Rel.		39,221			39,221	0.737		289,100
December	SJRPP		267,477			267,477	3.017		8,070,000
	PPAs								
Total			437,028			437,028	2.995		13,089,264
	UPS		3,106,196			3,106,196	4.138		128,521,619
Period	St. Lucie Rel.		352,982			352,982	0.596		2,102,300
Total	SJRPP		2,931,727			2,931,727	3.095		90,728,000
	PPAs		13,197			13,197	8.216		1,084,274
Total			6,404,103			6,404,103	3.473		222,436,193

Schedule: E8

Company: Florida Power & Light

Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2011 thru December 2011

(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)
2011 January	Qual. Facilities		357,636			357,636	3.668	3.668	13,118,570
Total			357,636			357,636	3.668	3.668	13,118,570
2011 February	Qual. Facilities		365,879			365,879	3.706	3.706	13,560,610
Total			365,879			365,879	3.706	3.706	13,560,610
2011 March	Qual. Facilities		348,898			348,898	3.715	3.715	12,960,754
Total			348,898			348,898	3.715	3.715	12,960,754
2011 April	Qual. Facilities		162,460			162,460	3.578	3.578	5,812,521
Total			162,460			162,460	3.578	3.578	5,812,521
2011 May	Qual. Facilities		300,733			300,733	3.728	3.728	11,210,361
Total			300,733			300,733	3.728	3.728	11,210,361
2011 June	Qual. Facilities		387,641			387,641	3.806	3.806	14,755,317
Total			387,641			387,641	3.806	3.806	14,755,317
Period Total	Qual. Facilities		1,923,247			1,923,247	3.713	3.713	71,418,133
Total			1,923,247			1,923,247	3.713	3.713	71,418,133

Schedule: E8

Company: Florida Power & Light

Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2011 thru December 2011

(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)
2011 July	Qual. Facilities		402,097			402,097	3.957	3.957	15,911,682
Total			402,097			402,097	3.957	3.957	15,911,682
2011 August	Qual. Facilities		401,906			401,906	3.879	3.879	15,591,655
Total			401,906			401,906	3.879	3.879	15,591,655
2011 September	Qual. Facilities		399,541			399,541	3.961	3.961	15,824,779
Total			399,541			399,541	3.961	3.961	15,824,779
2011 October	Qual. Facilities		315,809			315,809	3.848	3.848	12,152,957
Total			315,809			315,809	3.848	3.848	12,152,957
2011 November	Qual. Facilities		230,966			230,966	3.423	3.423	7,906,070
Total			230,966			230,966	3.423	3.423	7,906,070
2011 December	Qual. Facilities		399,695			399,695	3.635	3.635	14,527,407
Total			399,695			399,695	3.635	3.635	14,527,407
Period Total	Qual. Facilities		4,073,261			4,073,261	3.764	3.764	153,332,683
Total			4,073,261			4,073,261	3.764	3.764	153,332,683

Schedule: E9

Company: Florida Power & Light

Economy Energy Purchases

Estimated For the Period of : January 2011 Thru December 2011

(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)
January	Florida	C	4,150	4.266	177,047	5.284	219,304	42,257
2011	Non-Florida	C	18,250	4.596	838,855	5.430	990,940	152,085
Total			22,400	4.535	1,015,902	5.403	1,210,244	194,342
February	Florida	C	3,175	3.995	126,836	5.619	178,418	51,581
2011	Non-Florida	C	13,425	4.177	560,758	5.604	752,391	191,633
Total			16,600	4.142	687,594	5.607	930,809	243,215
March	Florida	C	5,025	3.304	166,002	4.802	241,286	75,283
2011	Non-Florida	C	21,800	3.512	765,650	4.817	1,050,209	284,559
Total			26,825	3.473	931,652	4.815	1,291,495	359,842
April	Florida	C	30,500	5.772	1,760,470	7.077	2,158,355	397,885
2011	Non-Florida	C	34,500	5.437	1,875,755	7.029	2,425,140	549,385
Total			65,000	5.594	3,636,225	7.052	4,583,495	947,270
May	Florida	C	130,500	5.422	7,075,905	6.926	9,037,850	1,961,945
2011	Non-Florida	C	106,750	5.092	5,435,648	7.103	7,582,325	2,146,678
Total			237,250	5.274	12,511,553	7.005	16,620,175	4,108,623
June	Florida	C	225,320	6.984	15,736,438	8.634	19,453,578	3,717,140
2011	Non-Florida	C	90,000	5.175	4,657,050	6.657	5,991,550	1,334,500
Total			315,320	6.468	20,393,488	8.070	25,445,128	5,051,640
Period	Florida	C	398,670	6.282	25,042,698	7.848	31,288,790	6,246,092
Total	Non-Florida	C	284,725	4.964	14,133,715	6.600	18,792,555	4,658,840
Total			683,395	5.733	39,176,414	7.328	50,081,345	10,904,932

Schedule: E9

Company: Florida Power & Light

Economy Energy Purchases

Estimated For the Period of : January 2011 Thru December 2011

(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)
July	Florida	C	100,000	6.118	6,117,500	8.123	8,123,200	2,005,700
2011	Non-Florida	C	79,750	5.994	4,780,288	8.328	6,641,373	1,861,085
Total			179,750	6.063	10,897,788	8.214	14,764,573	3,866,785
August	Florida	C	94,000	6.245	5,870,200	8.437	7,930,360	2,060,160
2011	Non-Florida	C	82,000	5.825	4,776,100	8.228	6,746,830	1,970,730
Total			176,000	6.049	10,646,300	8.339	14,677,190	4,030,890
September	Florida	C	97,250	6.793	6,606,265	9.555	9,292,493	2,686,228
2011	Non-Florida	C	55,100	6.172	3,400,534	9.438	5,200,163	1,799,629
Total			152,350	6.568	10,006,799	9.513	14,492,656	4,485,857
October	Florida	C	54,250	5.710	3,097,830	7.880	4,274,720	1,176,890
2011	Non-Florida	C	61,000	5.309	3,238,470	7.826	4,773,610	1,535,140
Total			115,250	5.498	6,336,300	7.851	9,048,330	2,712,030
November	Florida	C	18,500	2.831	523,760	4.065	751,980	228,220
2011	Non-Florida	C	35,000	2.836	992,460	4.064	1,422,260	429,800
Total			53,500	2.834	1,516,220	4.064	2,174,240	658,020
December	Florida	C	12,900	2.810	362,491	4.053	522,779	160,288
2011	Non-Florida	C	27,450	2.827	775,998	4.061	1,114,812	338,814
Total			40,350	2.822	1,138,489	4.058	1,637,591	499,102
Period	Florida	C	775,570	6.140	47,620,744	8.018	62,184,322	14,563,577
Total	Non-Florida	C	625,025	5.135	32,097,565	7.150	44,691,603	12,594,038
Total			1,400,595	5.692	79,718,309	7.631	106,875,924	27,157,615

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	NOV 10 - DEC 10	PRELIMINARY JAN 11 - DEC 11	DIFFERENCE $	 %
BASE	$43.01	$43.01	$0.00	0.00%
FUEL	$38.57	$41.19	$2.62	6.79%
CONSERVATION	$1.88	$3.64	$1.76	93.62%
CAPACITY PAYMENT	$6.21	$6.55	$0.34	5.48%
ENVIRONMENTAL	$1.79	$1.43	-$0.36	-20.11%
STORM RESTORATION SURCHARGE	$1.17	$1.17	$0.00	0.00%
SUBTOTAL	$92.63	$96.99	$4.36	4.71%
GROSS RECEIPTS TAX	$2.38	$2.49	$0.11	4.62%
TOTAL	**$95.01**	**$99.48**	$4.47	4.70%

Company: Florida Power & Light Company

Schedule H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL	ACTUAL	ESTIMATED/ ACTUAL	PROJECTED	(COLUMN 2)	(COLUMN 3)	(COLUMN 4)
		JAN - DEC 2008 - 2008 (COLUMN 1)	JAN - DEC 2009-2009 (COLUMN 2)	JAN-DEC 2010-2010 (COLUMN 3)	JAN-DEC 2011-2011 (COLUMN 4)	(COLUMN 1)	(COLUMN 2)	(COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	620,061,087	511,037,341	529,169,688	186,123,779	(17.6)	3.6	(64.8)
2	LIGHT OIL	3,478,693	4,145,784	36,330,786	10,808,000	19.2	776.3	(70.3)
3	COAL	148,805,782	161,167,047	156,319,115	172,498,000	8.3	(3.0)	10.3
4	GAS	4,746,598,653	4,030,867,582	3,248,292,851	3,401,160,849	(15.1)	(19.4)	4.7
5	NUCLEAR	111,595,515	127,944,491	142,066,481	147,886,700	14.7	11.0	-4.1
6	TOTAL ($)	5,830,539,731	4,835,162,249	4,112,178,922	3,918,477,328	(14.1)	(15.0)	(4.7)
	SYSTEM NET GENERATION							
7	HEAVY OIL	5,701,717	4,560,253	4,575,519	1,413,185	(20.0)	0.3	(69.1)
8	LIGHT OIL	17,493	21,046	82,683	57,696	20.3	292.9	(30.2)
9	COAL	6,422,947	6,362,894	6,295,658	6,795,022	(0.9)	(1.1)	7.9
10	GAS	58,819,728	62,728,250	67,101,143	71,022,150	6.8	7.0	5.8
11	NUCLEAR	24,024,374	22,893,259	22,994,968	20,930,855	(4.7)	0.4	(9.0)
12	SOLAR		12,489	69,357	227,767		455	228.4
13	TOTAL (MWH)	94,986,259	96,578,191	101,119,335	100,446,655	1.7	4.7	(0.7)
	UNITS OF FUEL BURNED							
14	HEAVY OIL (Bbl)	9,379,476	7,488,583	7,242,373	2,257,710	(20.2)	(3.3)	(68.8)
15	LIGHT OIL (Bbl)	38,182	51,727	453,331	108,199	35.5	776.4	(76.1)
16	COAL (TON)	793,861	755,687	2,115,066	3,598,010	(4.8)	179.9	70.1
17	GAS (MCF)	449,818,999	481,425,634	489,103,772	514,448,533	7.0	1.6	5.2
18	NUCLEAR (MMBTU)	261,160,298	249,692,895	255,450,271	233,788,606	(4.4)	2.3	(8.5)
	BTU'S BURNED (MMBTU)							
19	HEAVY OIL	60,210,324	48,005,849	46,160,227	14,449,340	(20.3)	(3.9)	(68.7)
20	LIGHT OIL	219,701	294,600	2,596,268	630,797	34.2	781.4	(75.7)
21	COAL	66,483,559	65,961,836	62,262,757	68,780,652	(0.8)	(5.6)	10.5
22	GAS	463,330,300	492,309,464	494,262,848	514,448,533	6.3	0.4	4.1
23	NUCLEAR	261,160,298	249,692,895	255,450,271	233,788,606	(4.4)	2.3	(8.5)
24	TOTAL (MMBTU)	851,404,182	856,264,844	860,724,171	832,097,928	0.6	0.5	(3.3)
	GENERATION MIX (%MWH)							
25	HEAVY OIL	6.00	4.72	4.52	1.41	-	-	-
26	LIGHT OIL	0.02	0.02	0.08	0.06	-	-	-
27	COAL	6.76	6.59	6.23	6.76			
28	GAS	61.92	64.95	66.36	70.71	-	-	-
29	NUCLEAR	25.29	23.70	22.74	20.84	-	-	-
30	SOLAR		0.01	0.07	0.23			
31	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
32	HEAVY OIL ($/Bbl)	66.1083	68.2422	73.0658	82.4392	3.2	7.1	12.8
33	LIGHT OIL ($/Bbl)	91.1088	80.1471	80.1419	99.8900	(12.0)	(0.0)	24.6
34	COAL ($/TON)	53.2455	90.0207	73.9074	47.9426	69.1	(17.9)	(35.1)
35	GAS ($/MCF)	10.5522	8.3728	6.6413	6.6113	(20.7)	(20.7)	(0.5)
36	NUCLEAR ($/MMBTU)	0.4273	0.5124	0.5561	0.6326	19.9	8.5	13.7
	FUEL COST PER MMBTU ($/MMBTU)							
37	HEAVY OIL	10.2983	10.6453	11.4662	12.8811	3.4	7.7	12.3
38	LIGHT OIL	15.8338	14.0630	13.9827	17.1339	(11.2)	(0.6)	22.5
39	COAL	2.2382	2.4432	2.5108	2.5079	9.2	2.8	(0.1)
40	GAS	10.2445	8.1877	6.5720	6.6113	(20.1)	(19.7)	0.6
41	NUCLEAR	0.4273	0.5124	0.5561	0.6326	19.9	8.5	13.7
42	TOTAL ($/MMBTU)	6.6132	5.8488	4.7776	4.7092	(14.6)	(15.4)	(1.4)
	BTU BURNED PER KWH (BTU/KWH)							
43	HEAVY OIL	10,560	10,527	10,088	10,225	(0.3)	(4.2)	1.4
44	LIGHT OIL	12,559	14,007	31,421	10,933	11.5	124.3	(65.2)
45	COAL	10,351	10,367	9,890	10,122	0.2	(4.6)	2.4
46	GAS	7,877	7,848	7,366	7,243	(0.4)	(6.1)	(1.7)
47	NUCLEAR	10,871	10,907	11,109	11,170	0.3	1.9	0.5
48	TOTAL (BTU/KWH)	8,963	8,866	8,512	8,284	(1.1)	(4.0)	(2.7)
	GENERATED FUEL COST PER KWH (c/KWH)							
49	HEAVY OIL	10.8750	11.2063	11.5652	13.1707	3.0	3.2	13.9
50	LIGHT OIL	19.8882	19.6985	43.9347	18.7327	(0.9)	123.0	(57.4)
51	COAL	2.3168	2.5328	2.4830	2.5386	9.3	(2.0)	2.2
52	GAS	8.0697	6.4259	4.8409	4.7889	(20.4)	(24.7)	(1.1)
53	NUCLEAR	0.4645	0.5589	0.6176	0.7085	20.3	10.5	14.4
54	TOTAL (c/KWH)	5.9277	5.0065	4.0667	3.9011	(15.5)	(18.8)	(4.1)

Note: Scherer coal is reported in MMBTU's only. Scherer coal is not included in TONS.

FLORIDA POWER & LIGHT COMPANY

Thirty-Seventh Revised Sheet No. 10.101
Cancels Thirty-Sixth Revised Sheet No. 10.101

(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 periods are as follows. In addition, As-Available Energy cost payments will include .0016¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1, 2010 – March 31, 2011	5.47	4.14	4.57
April 1, 2011 – September 30, 2011	6.13	5.46	5.67
October 1, 2011 – March 31, 2012	5.19	4.23	4.54
April 1, 2012 – September 30, 2012	6.00	5.49	5.66

A MW block size ranging from 94 MW to 123 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	1.0213
Secondary Voltage Delivery	1.0465

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	Nuclear	Oil	Gas	Coal
2010	22	2	59	6	12	.76	11.70	5.92	2.09
2011	20	1	62	7	10	.73	12.39	6.54	2.14
2012	21	1	63	6	10	.78	13.21	6.71	2.17
2013	24	0	60	6	10	.83	14.56	7.04	2.23
2014	23	0	61	6	10	.82	14.81	7.39	2.28
2015	22	0	61	6	11	.84	16.45	8.25	2.31
2016	22	1	66	6	6	.86	17.13	8.89	2.35
2017	22	1	66	6	6	.88	17.90	9.54	2.38
2018	21	1	66	6	6	.91	18.63	10.08	2.43
2019	21	1	67	5	6	.93	19.19	10.64	2.90

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

(Continued on Sheet No. 10.102)

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective:

(Continued from Sheet No. 10.102)

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 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 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	0.218%
Distribution Equipment	0.188%
Transmission Equipment	0.102%

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)

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2011 -DECEMBER 2011

		(a) DOLLARS	(b) MWH	(c) ¢/KWH
1	Fuel Cost of System Net Generation (E3)	$3,918,477,328	100,446,655	3.9011
2	Nuclear Fuel Disposal Costs (E2)	19,509,650	20,930,855	0.0932
2a	Scherer Unit 4 Steam Turbine Upgrade	342,418	100,446,655	0.0003
3	Fuel Cost of Sales to FKEC / CKW (E2)	(45,215,546)	(974,289)	4.6409
4	TOTAL COST OF GENERATED POWER	$3,893,113,850	99,472,367	3.9138
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	222,436,193	6,404,103	3.4733
6	Energy Cost of Economy Purchases (Florida) (E9)	47,620,744	775,570	6.1401
7	Energy Cost of Economy Purchases (Non-Florida) (E9)	32,097,565	625,025	5.1354
8	Payments to Qualifying Facilities (E8)	153,332,683	4,073,261	3.7644
9	TOTAL COST OF PURCHASED POWER	$455,487,185	11,877,959	3.8347
10	TOTAL AVAILABLE KWH (LINE 6 + LINE 11)		111,350,326	
11	Fuel Cost of Economy Sales (E6)	(40,232,035)	(873,500)	4.6058
12	Gain on Economy Sales (E6)	(9,692,706)	(1,252,119)	0.7741
13	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(2,446,761)	(378,619)	0.6462
14	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
15	TOTAL FUEL COST AND GAINS OF POWER SALES	($52,371,501)	(1,252,119)	4.1826
16	Net Inadvertent Interchange	0	0	
17	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 6 + 11 + 18)	$4,296,229,533	110,098,206	3.9022
18	Net Unbilled Sales	(25,334,836) **	(649,248)	(0.0245)
19	Company Use	12,888,689 **	330,295	0.0125
20	T & D Losses	279,254,920 **	7,156,383	0.2704
21	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$4,296,229,533	103,260,777	4.1606
22	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$49,492,135	1,189,558	4.1606
23	Jurisdictional MWH Sales	$4,246,737,398	102,071,219	4.1606
24	Jurisdictional Loss Multiplier	-	-	1.00083
25	Jurisdictional MWH Sales Adjusted for Line Losses	$4,250,262,190	102,071,219	4.1640
26	FINAL TRUE-UP Jan 09- Dec 09 $8,771,414 underrecovery; EST/ACT TRUE-UP Jan 10 - Dec 10 $286,129,908 underrecovery	294,901,322	102,071,219	0.2889
27	TOTAL JURISDICTIONAL FUEL COST	$4,545,163,512	102,071,219	4.4529
28	Revenue Tax Factor			1.00072
29	Fuel Factor Adjusted for Taxes	4,548,436,030		4.4561
30	GPIF ***	$8,115,900	102,071,219	0.0080
31	Fuel Factor including GPIF (Line 32 + Line 33)	4,556,551,930	102,071,219	4.4641
32	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			4.464

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

Florida Power & Light Company
Fuel Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer 4 Turbine Upgrade
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$4,495,445	$4,495,445
	c. Retirements / Reserve activities		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	0	4,495,445	n/a
3.	Less: Accumulated Depreciation	$0	0	0	0	0	0	4,870	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$4,490,575	n/a
6.	Average Net Investment		0	0	0	0	0	2,245,287	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		0	0	0	0	0	14,323	$14,323
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		0	0	0	0	0	3,644	$3,644
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	4,870	$4,870
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$22,836	$22,836

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages XX-XX.
(B) Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt component of 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages XX-XX.
(F) Applicable amortization period(s). See Form 42-8A, pages XX-XX.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

APPENDIX II
BASED ON TRADITIONAL METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

Florida Power & Light Company
Fuel Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer 4 Turbine Upgrade
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$985,044	$0	$0	$0	$0	$5,480,489
	c. Retirements / Reserve activities		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$4,495,445	4,495,445	5,480,489	5,480,489	5,480,489	5,480,489	5,480,489	n/a
3.	Less: Accumulated Depreciation	$4,870	15,677	27,552	39,426	51,301	63,175	75,049	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,490,575	$4,479,768	$5,452,937	$5,441,063	$5,429,189	$5,417,314	$5,405,440	n/a
6.	Average Net Investment		4,485,171	4,966,352	5,447,000	5,435,126	5,423,251	5,411,377	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		28,611	31,680	34,746	34,671	34,595	34,519	213,145
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		7,279	8,059	8,839	8,820	8,801	8,782	54,224
8.	Investment Expenses								
	a. Depreciation (E)		10,807	11,874	11,874	11,874	11,874	11,874	75,049
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$46,697	$51,614	$55,460	$55,365	$55,270	$55,175	$342,418

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages XX-XX.
(B) Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt component of 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages XX-XX.
(F) Applicable amortization period(s). See Form 42-8A, pages XX-XX.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

APPENDIX II
BASED ON TRADITIONAL METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2011 - DECEMBER 2011

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	31.48	36.17
OFF PEAK	68.52	63.83
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$4,296,229,533	$1,553,946,095	$2,742,283,438
2	MWH SALES	103,260,777	32,508,973	70,751,804
3	COST PER KWH SOLD	4.1606	4.7801	3.8759
4	JURISDICTIONAL LOSS FACTOR	1.00083	1.00083	1.00083
5	JURISDICTIONAL FUEL FACTOR	4.1640	4.7840	3.8791
6	TRUE-UP	0.2889	0.2889	0.2889
7				
8	TOTAL	4.4529	5.0729	4.1680
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	4.4561	5.0766	4.1710
11	GPIF	0.0080	0.0080	0.0080
12	RECOVERY FACTOR including GPIF	4.4641	5.0846	4.1790
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.464	5.085	4.179

HOURS:	ON-PEAK	25.10 %
	OFF-PEAK	74.90 %

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2011 THROUGH SEPTEMBER 2011 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	24.30	28.83
OFF PEAK	75.70	71.17
	100.00	100.00

SDTR FUEL RECOVERY CALCULATION

	TOTAL	ON-PEAK	OFF-PEAK
1 TOTAL FUEL & NET POWER TRANS	$4,296,229,533	$1,238,683,027	$3,057,546,506
2 MWH SALES	103,260,777	25,089,710	78,171,067
3 COST PER KWH SOLD	4.1606	4.9370	3.9114
4 JURISDICTIONAL LOSS FACTOR	1.00083	1.00083	1.00083
5 JURISDICTIONAL FUEL FACTOR	4.1640	4.9411	3.9146
6 TRUE-UP	0.2889	0.2889	0.2889
7			
8 TOTAL	4.4529	5.2300	4.2035
9 REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10 SDTR RECOVERY FACTOR	4.4561	5.2338	4.2065
11 GPIF	0.0080	0.0080	0.0080
12 SDTR RECOVERY FACTOR including GPIF	4.4641	5.2418	4.2145
13 SDTR RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.464	5.242	4.215

HOURS:	ON-PEAK	19.67 %
	OFF-PEAK	80.33 %

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1D, Page 1 of 2.

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E
Page 1 of 2

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

JANUARY 2011 - DECEMBER 2011

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh		4.464	1.00207	4.119
	all additional kWh		4.464	1.00207	5.119
A	GS-1, SL-2, GSCU-1, WIES-1		4.464	1.00207	4.473
A-1*	SL-1, OL-1, PL-1		4.324	1.00207	4.333
B	GSD-1		4.464	1.00202	4.473
C	GSLD-1 & CS-1		4.464	1.00116	4.469
D	GSLD-2, CS-2, OS-2 & MET		4.464	0.99426	4.438
E	GSLD-3 & CS-3		4.464	0.96229	4.296
A	RST-1, GST-1	ON-PEAK	5.085	1.00207	5.095
		OFF-PEAK	4.179	1.00207	4.188
B	GSDT-1, CILC-1(G),	ON-PEAK	5.085	1.00201	5.095
	HLFT-1 (21-499 kW)	OFF-PEAK	4.179	1.00201	4.187
C	GSLDT-1, CST-1,	ON-PEAK	5.085	1.00127	5.091
	HLFT-2 (500-1,999 kW)	OFF-PEAK	4.179	1.00127	4.184
D	GSLDT-2, CST-2,	ON-PEAK	5.085	0.99552	5.062
	HLFT-3 (2,000+ kW)	OFF-PEAI	4.179	0.99552	4.160
E	GSLDT-3,CST-3,	ON-PEAK	5.085	0.96229	4.893
	CILC -1(T)	OFF-PEAK	4.179	0.96229	4.021
	& ISST-1(T)				
F	CILC -1(D) &	ON-PEAK	5.085	0.99484	5.058
	ISST-1(D)	OFF-PEAK	4.179	0.99484	4.157

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

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2011 THROUGH SEPTEMBER 2011 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

(1) GROUP	(2) OTHERWISE APPLICABLE RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) SDTR FUEL RECOVERY FACTOR
B	GSD(T)-1	ON-PEAK	5.242	1.00202	5.252
		OFF-PEAK	4.215	1.00202	4.223
C	GSLD(T)-1	ON-PEAK	5.242	1.00123	5.248
		OFF-PEAK	4.215	1.00123	4.220
D	GSLD(T)-2	ON-PEAK	5.242	0.99599	5.221
		OFF-PEAK	4.215	0.99599	4.198

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2011 - DECEMBER 2011

LINE NO.		(a) JANUARY ESTIMATED	(b) FEBRUARY ESTIMATED	(c) MARCH ESTIMATED	(d) APRIL ESTIMATED	(e) MAY ESTIMATED	(f) JUNE ESTIMATED	(g) 6 MONTH SUB-TOTAL	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$282,465,430	$246,439,168	$277,867,113	$298,019,007	$343,936,505	$348,794,790	$1,797,522,011	1
2	NUCLEAR FUEL DISPOSAL	1,578,003	1,396,693	1,438,035	1,469,633	1,805,809	1,923,091	9,611,264	2
2a	SCHERER UNIT 4 STEAM TURBINE UPGRADE	0	0	0	0	0	22,836	22,836	2a
3	FUEL COST OF POWER SOLD	(6,746,669)	(8,210,258)	(5,030,664)	(2,391,451)	(1,574,033)	(1,659,181)	(25,612,255)	3
4	GAIN ON ECONOMY SALES	(1,823,390)	(1,923,974)	(1,132,972)	(365,649)	(233,823)	(256,730)	(5,736,539)	4
5	FUEL COST OF PURCHASED POWER	17,001,688	15,507,270	12,095,521	20,064,019	22,693,723	20,603,441	107,965,664	5
6	QUALIFYING FACILITIES	13,118,570	13,560,610	12,960,754	5,812,521	11,210,361	14,755,317	71,418,133	6
7	ENERGY COST OF ECONOMY PURCHASES	1,015,902	687,594	931,652	3,636,225	12,511,553	20,393,488	39,176,414	7
8	FUEL COST OF SALES TO FKEC / CKW	(3,215,041)	(3,149,627)	(3,244,019)	(3,571,096)	(3,862,515)	(4,190,308)	(21,232,605)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$303,394,494	$264,307,477	$295,885,422	$322,673,209	$386,487,579	$400,386,743	$1,973,134,923	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,264,331	7,246,664	7,396,703	7,356,403	8,317,721	9,362,714	47,944,537	10
11	COST PER KWH SOLD (¢/KWH)	3.6711	3.6473	4.0002	4.3863	4.6466	4.2764	4.1155	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	3.6742	3.6503	4.0036	4.3899	4.6504	4.2799	4.1189	13
14	TRUE-UP (¢/KWH)	0.3005	0.3434	0.3360	0.3382	0.2987	0.2655	0.3111	14
15	TOTAL	3.9747	3.9937	4.3396	4.7281	4.9491	4.5454	4.4300	15
16	REVENUE TAX FACTOR 0.00072	0.0029	0.0029	0.0031	0.0034	0.0036	0.0033	0.0032	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	3.9776	3.9966	4.3427	4.7315	4.9527	4.5487	4.4332	17
18	GPIF (¢/KWH)	0.0083	0.0094	0.0092	0.0093	0.0082	0.0073	0.0086	18
19	RECOVERY FACTOR including GPIF	3.9859	4.0060	4.3519	4.7408	4.9609	4.5560	4.4418	19
20	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	3.986	4.006	4.352	4.741	4.961	4.556	4.442	20

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2011 - DECEMBER 2011

LINE NO.		(h) JULY ESTIMATED	(i) AUGUST ESTIMATED	(j) SEPTEMBER ESTIMATED	(k) OCTOBER ESTIMATED	(l) NOVEMBER ESTIMATED	(m) DECEMBER ESTIMATED	(n) 12 MONTH PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$387,813,785	$400,954,046	$395,820,616	$370,731,454	$288,661,681	$276,973,737	$3,918,477,328	1
2	NUCLEAR FUEL DISPOSAL	1,987,193	1,932,293	1,374,103	1,419,905	1,405,498	1,779,394	$19,509,650	2
2a	SCHERER UNIT 4 STEAM TURBINE UPGRADE	46,697	51,614	55,460	55,365	55,270	55,175	$342,417	2a
3	FUEL COST OF POWER SOLD	(2,287,013)	(2,822,926)	(1,290,210)	(2,233,840)	(3,057,590)	(5,374,962)	($42,678,796)	3
4	GAIN ON ECONOMY SALES	(332,757)	(483,027)	(160,097)	(329,025)	(955,689)	(1,695,572)	($9,692,706)	4
5	FUEL COST OF PURCHASED POWER	21,970,282	21,391,572	22,938,069	21,986,795	13,094,526	13,089,284	$222,436,193	5
6	QUALIFYING FACILITIES	15,911,682	15,591,655	15,824,779	12,152,957	7,906,070	14,527,407	$153,332,683	6
7	ENERGY COST OF ECONOMY PURCHASES	10,897,788	10,646,300	10,006,799	6,336,300	1,516,220	1,138,489	$79,718,309	7
8	FUEL COST OF SALES TO FKEC / CKW	(4,331,369)	(4,458,628)	(4,385,071)	(3,969,481)	(3,589,740)	(3,248,653)	($45,215,546)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$431,676,287	$442,802,899	$440,184,447	$406,150,431	$305,036,246	$297,244,299	$4,296,229,532	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	9,972,647	9,903,541	10,377,478	8,910,784	8,245,065	7,906,722	103,260,777	10
11	COST PER KWH SOLD (¢/KWH)	4.3286	4.4712	4.2417	4.5580	3.6996	3.7594	4.1606	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	4.3322	4.4749	4.2452	4.5617	3.7027	3.7625	4.1640	13
14	TRUE-UP (¢/KWH)	0.2491	0.2511	0.2396	0.2793	0.3018	0.3141	0.2889	14
15	TOTAL	4.5813	4.7260	4.4848	4.8410	4.0045	4.0766	4.4529	15
16	REVENUE TAX FACTOR 0.00072	0.0033	0.0034	0.0032	0.0035	0.0029	0.0029	0.0032	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	4.5846	4.7294	4.4880	4.8445	4.0074	4.0795	4.4561	17
18	GPIF (¢/KWH)	0.0069	0.0069	0.0066	0.0077	0.0083	0.0086	0.0080	18
19	RECOVERY FACTOR including GPIF	4.5915	4.7363	4.4946	4.8522	4.0157	4.0881	4.4641	19
20	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	4.592	4.736	4.495	4.852	4.016	4.088	4.464	20

APPENDIX II
BASED ON TRADITIONAL METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

2011 Jan-Dec

	RS-1 standard	proposed inverted fuel factors	target fuel revenues	rounded
First 1000 kWh	36,523,505,744	0.04119114	1,504,444,827.66	4.119
All additional kWh	20,004,455,892	0.05119114	1,024,050,896.32	5.119
	56,527,961,636		2,528,495,723.98	
avg fuel factor	4.464			
RS-1 loss mult	1.00207		0.00	
average fuel Factor	4.473			
target fuel revenues	2,528,495,723.98			

COMPANY: FLORIDA POWER & LIGHT COMPANY **SCHEDULE E10**

	NOV 10 - DEC 10	PRELIMINARY JAN 11 - DEC 11	DIFFERENCE $	DIFFERENCE %
BASE	$43.01	$43.01	$0.00	0.00%
FUEL	$38.57	$41.19	$2.62	6.79%
CONSERVATION	$1.88	$3.64	$1.76	93.62%
CAPACITY PAYMENT	$6.21	$6.55	$0.34	5.48%
ENVIRONMENTAL	$1.79	$1.43	-$0.36	-20.11%
STORM RESTORATION SURCHARGE	$1.17	$1.17	$0.00	0.00%
SUBTOTAL	$92.63	$96.99	$4.36	4.71%
GROSS RECEIPTS TAX	$2.38	$2.49	$0.11	4.62%
TOTAL	**$95.01**	**$99.48**	$4.47	4.70%

APPENDIX III

CAPACITY COST RECOVERY

JANUARY 2011 – DECEMBER 2011 FACTORS

JUNE 2011 – DECEMBER 2011 FACTORS BASED ON STIPULATION AND SETTLEMENT AGREEMENT

TJK-6
DOCKET NO. 100001-EI
FPL WITNESS: T.J.KEITH
EXHIBIT ________
PAGES 1-14
SEPTEMBER 1, 2010

APPENDIX III
CAPACITY COST RECOVERY

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CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2010

LINE NO.		(1) ACTUAL JAN 2010	(2) ACTUAL FEB 2010	(3) ACTUAL MAR 2010	(4) ACTUAL APR 2010	(5) ACTUAL MAY 2010	(6) ACTUAL JUN 2010
1.	Payments to Non-cogenerators (UPS & SJRPP)	$22,025,054	$21,859,869	$21,638,970	$21,873,834	$22,635,491	$6,797,830
2.	Short-Term Capacity Purchases CCR	613,800	613,800	286,440	286,440	286,440	8,561,020
3.	QF Capacity Charges	26,440,047	27,333,692	27,247,711	24,947,038	25,051,318	25,097,317
4a.	SJRPP Suspension Accrual	134,495	134,495	134,495	134,495	134,495	134,495
4b.	Return on SJRPP Suspension Liability	(483,556)	(484,800)	(420,545)	(421,621)	(422,697)	(423,773)
5.	Incremental Plant Security Costs-Order No. PSC-02-1761	3,099,362	3,418,397	3,792,765	2,074,049	2,781,813	2,180,832
6.	Transmission of Electricity by Others	0	0	378	21	0	635,637
7.	Transmission Revenues from Capacity Sales	(229,135)	(166,367)	(98,580)	(48,815)	(53,081)	33,367
8.	Total (Lines 1 through 7)	$ 51,600,067	$ 52,709,085	$ 52,581,634	$ 48,845,442	$ 50,413,779	$ 43,016,725
9.	Jurisdictional Separation Factor (a)	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%
10.	Jurisdictional Capacity Charges	50,584,087	51,671,270	51,546,328	47,883,699	49,421,157	42,169,747
11.	Nuclear Cost Recovery Costs	5,376,780	2,810,247	3,697,663	4,470,512	5,019,959	4,145,679
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	0	0	0	0
13.	Jurisdictional Capacity Charges Authorized	$ 51,215,401	$ 49,736,051	$ 55,243,991	$ 52,354,211	$ 54,441,116	$ 46,315,426
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 53,556,600	$ 44,803,546	$ 43,326,374	$ 40,527,864	$ 48,188,481	$ 56,628,272
15.	Prior Period True-up Provision	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 47,633,513	$ 38,880,459	$ 37,403,287	$ 34,604,777	$ 42,265,394	$ 50,705,185
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(3,581,888)	(10,855,592)	(17,840,704)	(17,749,434)	(12,175,722)	4,389,759
18.	Interest Provision for Month	(8,171)	(8,594)	(10,282)	(12,947)	(18,926)	(22,332)
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(71,077,044)	(68,744,016)	(73,685,116)	(85,613,014)	(97,452,309)	(103,723,869)
20.	Deferred True-up - Over/(Under) Recovery	20,891,498	20,891,498	20,891,498	20,891,498	20,891,498	20,891,498
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	5,923,087	5,923,087	5,923,087	5,923,087	5,923,087	5,923,087
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (47,852,518)	$ (52,793,618)	$ (64,721,516)	$ (76,560,811)	$ (82,832,371)	$ (72,541,857)

Notes: **(a) Jurisdictional separation factor approved by the FPSC in Order No. PSC-10-0153-FOF-EI, Docket NO. 080677-EI.**

(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. 930001-EI, filed July 8, 1993.

Note that effective March 2010 this adjustment is no longer required as per Order No PSC-10-0153-FOF-EI, Docket No 080677-EI

REVISED

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2010

LINE NO.		(7) ACTUAL JUL 2010	(8) ESTIMATED AUG 2010	(9) ESTIMATED SEP 2010	(10) ESTIMATED OCT 2010	(11) ESTIMATED NOV 2010	(12) ESTIMATED DEC 2010	(13) TOTAL	LINE NO.
1.	Payments to Non-cogenerators (UPS & SJRPP)	$6,847,162	$7,028,944	$7,028,944	$7,028,944	$7,028,944	$7,028,944	$158,822,931	1.
2.	Short-Term Capacity Purchases CCR	8,561,020	8,922,124	8,922,124	7,980,964	7,980,964	8,308,324	61,323,459	2.
3.	QF Capacity Charges	25,053,885	24,381,882	24,381,882	24,381,882	24,381,882	24,381,882	303,080,418	3.
4a.	SJRPP Suspension Accrual	134,495	134,495	134,495	134,495	134,495	134,495	1,613,942	4a.
4b.	Return on SJRPP Suspension Liability	(424,850)	(425,926)	(427,002)	(428,078)	(429,154)	(430,231)	(5,222,233)	4b.
5.	Incremental Plant Security Costs-Order No. PSC-02-1761	2,056,556	4,999,285	5,948,155	5,085,988	7,005,556	8,138,897	50,581,654	5.
6.	Transmission of Electricity by Others	492,651	1,091,942	1,031,033	1,039,719	1,664,984	1,619,901	7,576,264	6.
7.	Transmission Revenues from Capacity Sales	(25,805)	(132,593)	(43,013)	(88,095)	(184,671)	(390,068)	(1,426,855)	7.
8.	Total (Lines 1 through 7)	$ 42,695,115	$ 46,000,153	$ 46,976,618	$ 45,135,818	$ 47,582,999	$ 48,792,144	$ 576,349,580	8.
9.	Jurisdictional Separation Factor (a)	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	N/A	9.
10.	Jurisdictional Capacity Charges	41,854,469	45,094,433	46,051,672	44,247,117	46,646,113	47,831,452	565,001,544	10.
11.	Nuclear Cost Recovery Costs	6,739,324	4,870,322	4,783,182	7,748,437	6,168,419	6,845,841	62,676,365	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	0	0	0	0	0	0	(9,490,932)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 48,593,793	$ 49,964,755	$ 50,834,854	$ 51,995,553	$ 52,814,532	$ 54,677,293	$ 618,186,977	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 59,308,798	$ 55,607,966	$ 58,306,298	$ 50,010,957	$ 46,249,812	$ 44,418,370	$ 600,933,338	14.
15.	Prior Period True-up Provision	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)	(71,077,044)	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 53,385,711	$ 49,684,879	$ 52,383,211	$ 44,087,870	$ 40,326,725	$ 38,495,283	$ 529,856,294	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	4,791,917	(279,876)	1,548,357	(7,907,683)	(12,487,807)	(16,182,010)	(88,330,682)	17.
18.	Interest Provision for Month	(17,636)	(13,770)	(12,243)	(11,606)	(12,606)	(14,572)	(163,685)	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(93,433,355)	(82,735,987)	(77,106,546)	(69,647,346)	(71,643,548)	(78,220,874)	(71,077,044)	19.
20.	Deferred True-up - Over/(Under) Recovery	20,891,498	20,891,498	20,891,498	20,891,498	20,891,498	20,891,498	20,891,498	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	5,923,087	5,923,087	5,923,087	5,923,087	5,923,087	5,923,087	71,077,044	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (61,844,489)	$ (56,215,048)	$ (48,755,848)	$ (50,752,050)	$ (57,329,376)	$ (67,602,871)	$ (67,602,870)	22.

Notes: **(a) Jurisdictional separation factor approved by the FPSC in Order No. PSC-10-0153-FOF-EI, Docket NO. 080677-EI.**

(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. 930001-EI, filed July 8, 1993. Note that effective March 2010 this adjustment is no longer required as per Order No PSC-10-0153-FOF-EI, Docket No 080677-EI.

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
JANUARY 2011 THROUGH DECEMBER 2011

	PROJECTED												
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. CAPACITY PAYMENTS TO NON-COGENERATORS	$15,633,588	$15,633,588	$15,306,228	$15,306,228	$15,306,228	$16,247,388	$16,247,388	$16,247,388	$16,247,388	$15,306,228	$15,306,228	$15,633,588	$188,421,452
2. CAPACITY PAYMENTS TO COGENERATORS	$22,675,340	$22,675,340	$22,675,340	$22,675,340	$22,675,340	$22,675,340	$22,675,340	$22,675,340	$22,675,340	$22,675,340	$22,675,340	$22,675,340	$272,104,074
3. SJRPP SUSPENSION ACCRUAL	$ 134,495	$ 134,495	$ 134,495	$ 134,495	$ 134,495	$ 134,495	$ 134,495	$ 134,495	$ 134,495	$ 134,495	$ 134,495	$ 134,495	$1,613,943
4. RETURN REQUIREMENTS ON SJRPP SUSPENSION LIABILITY	$ (431,307)	$ (432,383)	$ (433,459)	$ (434,535)	$ (435,612)	$ (436,688)	$ (437,764)	$ (438,840)	$ (439,916)	$ (440,993)	$ (442,069)	$ (443,145)	($5,246,711)
5. INCREMENTAL PLANT SECURITY COSTS	$ 4,112,587	$ 4,112,587	$ 4,112,587	$ 4,112,587	$ 4,112,587	$ 4,112,587	$ 4,112,587	$ 4,112,587	$ 4,112,587	$ 4,112,587	$ 4,112,587	$ 4,112,587	$49,351,038
6. TRANSMISSION OF ELECTRICITY BY OTHERS	1,560,363	1,530,751	1,631,970	1,256,793	1,113,828	1,255,680	1,196,339	1,271,009	1,121,024	1,204,747	1,794,465	1,832,307	$16,769,276
7. TRANSMISSION REVENUES FROM CAPACITY SALES	(416,855)	(463,301)	(334,778)	(125,101)	(70,737)	(70,520)	(91,663)	(132,593)	(43,013)	(88,095)	(184,671)	(390,068)	($2,411,394)
8. SYSTEM TOTAL	$43,268,210	$43,191,076	$43,092,382	$42,925,806	$42,836,128	$43,918,282	$43,836,721	$43,869,385	$43,807,904	$42,904,308	$43,396,374	$43,555,103	$520,801,679
9. JURISDICTIONAL % *													98.03105%
10. JURISDICTIONALIZED CAPACITY PAYMENTS													$510,351,292
11. 2009 FINAL TRUE-UP – (overrecovery)/underrecovery ($20,891,498)			2010 EST \ ACT TRUE-UP – (overrecovery)/underrecovery $88,494,368										$67,602,870
12. NUCLEAR COST RECOVERY CLAUSE													$31,288,445
13. TOTAL (Lines 11+12+13+14+15)													$609,242,607
14. REVENUE TAX MULTIPLIER													1.00072
15. TOTAL RECOVERABLE CAPACITY PAYMENTS													$609,681,261

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN.(MW)	%
FPSC	18,137	98.03105%
FERC	364	1.96895%
TOTAL	18,501	100.00000%

* BASED ON 2010 RATE CASE AS APPROVED BY THE FPSC

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2011 THROUGH DECEMBER 2011

Rate Schedule	(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/RST1	63.207%	51,937,791,952	9,380,304	1.08577530	1.06671356	55,402,746,952	10,184,902	50.94562%	56.15680%
GS1/GST1	66.464%	5,916,481,523	1,016,181	1.08577530	1.06671356	6,311,191,068	1,103,344	5.80346%	6.08354%
GSD1/GSDT1/HLFT1 (21-499 kW)	76.006%	24,983,108,880	3,752,274	1.08569164	1.06664979	26,648,227,841	4,073,813	24.50439%	22.46191%
OS2	67.825%	13,470,304	2,267	1.05612737	1.04404188	14,063,561	2,394	0.01293%	0.01320%
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	79.376%	11,197,980,511	1,610,444	1.08463232	1.06586957	11,935,586,672	1,746,740	10.97537%	9.63105%
GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	88.611%	2,112,911,852	272,202	1.07667781	1.05974513	2,239,148,045	293,074	2.05901%	1.61593%
GSLD3/GSLDT3/CS3/CST3	90.919%	243,243,788	30,541	1.03054203	1.02436840	249,171,250	31,474	0.22913%	0.17354%
ISST1D	70.728%	0	0	1.05612737	1.04404188	0	0	0.00000%	0.00000%
ISST1T	139.551%	0	0	1.03054203	1.02436840	0	0	0.00000%	0.00000%
SST1T	139.551%	129,164,990	10,566	1.03054203	1.02436840	132,312,534	10,889	0.12167%	0.06004%
SST1D1/SST1D2/SST1D3	70.728%	7,233,373	1,167	1.05612737	1.04404188	7,551,945	1,233	0.00694%	0.00680%
CILC D/CILC G	90.365%	3,223,049,150	407,156	1.07583393	1.05948563	3,414,774,259	438,032	3.14006%	2.41519%
CILC T	94.857%	1,524,897,373	183,513	1.03054203	1.02436840	1,562,056,682	189,118	1.43639%	1.04275%
MET	71.410%	92,301,968	14,755	1.05612737	1.04404188	96,367,120	15,583	0.08861%	0.08592%
OL1/SL1/PL1	203.422%	626,961,667	35,184	1.08577530	1.06671356	668,788,512	38,202	0.61498%	0.21064%
SL2, GSCU1	100.228%	62,621,669	7,132	1.08577530	1.06671356	66,799,384	7,744	0.06143%	0.04270%
TOTAL		102,071,219,000	16,723,686			108,748,785,825	18,136,542	100.00%	100.00%

(1) AVG 12 CP load factor based on 2010 load research data per Order No. PSC-10-0153-FOF-EI issued in Docket Nos. 080677-EI and 090130-EI on March 17, 2010.
(2) Projected kwh sales for the period January 2011 through December 2011
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 2010 demand losses as approved in Order No. PSC-10-0153-FOF-EI issued in Docket Nos. 080677-EI and 090130-EI on March 17, 2010.
(5) Based on 2010 energy losses as approved in Order No. PSC-10-0153-FOF-EI issued in Docket Nos. 080677-EI and 090130-EI on March 17, 2010.
(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
JANUARY 2011 THROUGH DECEMBER 2011

Rate Schedule	(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/RST1	50.94562%	56.15680%	$23,892,763	$316,040,769	$339,933,532	51,937,791,952	-	-	-	0.00655
GS1/GST1/WIES1	5.80346%	6.08354%	$2,721,739	$34,237,117	$36,958,856	5,916,481,523	-	-	-	0.00625
GSD1/GSDT1/HLFT1 (21-499 kW)	24.50439%	22.46191%	$11,492,206	$126,411,721	$137,903,927	24,983,108,880	48.67059%	70,316,457	1.96	-
OS2	0.01293%	0.01320%	$6,065	$74,287	$80,352	13,470,304	-	-	-	0.00597
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	10.97537%	9.63105%	$5,147,293	$54,201,901	$59,349,194	11,197,980,511	63.68015%	24,088,668	2.46	-
GSLD2/GSLDT2/CS2/CST2/HLFT3 (2,000+ kW)	2.05901%	1.61593%	$965,646	$9,094,180	$10,059,826	2,112,911,852	68.37874%	4,232,894	2.38	-
GSLD3/GSLDT3/CS3/CST3	0.22913%	0.17354%	$107,457	$976,648	$1,084,105	243,243,788	73.56846%	452,926	2.39	-
ISST1D	0.00000%	0.00000%	$0	$0	$0	0	52.36474%	0	**	-
ISST1T	0.00000%	0.00000%	$0	$0	$0	0	14.03656%	0	**	-
SST1T	0.12167%	0.06004%	$57,061	$337,889	$394,950	129,164,990	14.03656%	1,260,554	**	-
SST1D1/SST1D2/SST1D3	0.00694%	0.00680%	$3,257	$38,260	$41,517	7,233,373	52.36474%	18,923	**	-
CILC D/CILC G	3.14006%	2.41519%	$1,472,642	$13,592,273	$15,064,915	3,223,049,150	74.83495%	5,899,831	2.55	-
CILC T	1.43639%	1.04275%	$673,646	$5,868,392	$6,542,038	1,524,897,373	81.55360%	2,561,384	2.55	-
MET	0.08861%	0.08592%	$41,559	$483,545	$525,104	92,301,968	59.46021%	212,648	2.47	-
OL1/SL1/PL1	0.61498%	0.21064%	$288,419	$1,185,420	$1,473,839	626,961,667	-	-	-	0.00235
SL2/GSCU1	0.06143%	0.04270%	$28,808	$240,299	$269,107	62,621,669	-	-	-	0.00430
TOTAL			$46,898,561	$562,782,701	$609,681,261	102,071,219,000		109,044,285		

7

Note:There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

(1) Obtained from Page 2, Col(8)
(2) Obtained from Page 2, Col(9)
(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 January 2011 through December 2011
(7) (kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))
(8) Col (6) / ((7) *730)
(9) Col (5) / (8)
(10) Col (5) / (6)

Totals may not add due to rounding

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

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

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

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
ISST1D	$0.30	$0.14
ISST1T	$0.29	$0.14
SST1T	$0.29	$0.14
SST1D1/SST1D2/SST1D3	$0.30	$0.14

Florida Power & Light Company
Schedule E12 - Capacity Costs

2011 Projection

Contract	Capacity MW	Term Start	Term End	Contract Type
Cedar Bay	250	1/25/1994	12/31/2024	QF
Indiantown	330	12/22/1995	12/1/2025	QF
Broward North - 1991 Agreement	11	1/1/1993	12/31/2026	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF

QF = Qualifying Facility

2011 Projection Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	11,199,167	11,199,167	11,199,167	11,199,167	11,199,167	11,199,167	11,199,167	11,199,167	11,199,167	11,199,167	11,199,167	11,199,167	134,390,000
ICL	11,074,958	11,074,958	11,074,958	11,074,958	11,074,958	11,074,958	11,074,958	11,074,958	11,074,958	11,074,958	11,074,958	11,074,958	132,899,494
BN-NEG	304,370	304,370	304,370	304,370	304,370	304,370	304,370	304,370	304,370	304,370	304,370	304,370	3,652,440
BS-NEG	96,845	96,845	96,845	96,845	96,845	96,845	96,845	96,845	96,845	96,845	96,845	96,845	1,162,140
Total	22,675,340	22,675,340	22,675,340	22,675,340	22,675,340	22,675,340	22,675,340	22,675,340	22,675,340	22,675,340	22,675,340	22,675,340	272,104,074

Florida Power & Light Company
Docket No. 100001-EI
Schedule E12
Page 2 of 2

CONFIDENTIAL

Contract	Counterparty	Identification	Contract End Date
1	Southern Company (Oleander)	Other Entity	May 31, 2012
2	Southern Company (UPS Scherer)	Other Entity	December 31, 2015
3	Southern Company (UPS Harris)	Other Entity	December 31, 2015
4	Southern Company (UPS Franklin)	Other Entity	December 31, 2015
5	JEA-SJRPP	Other Entity	September 30, 2021

Capacity in MW

Contract	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
1	155	155	155	155	155	155	155	155	155	155	155	155
2	163	163	163	163	163	163	163	163	163	163	163	163
3	600	600	600	600	600	600	600	600	600	600	600	600
4	190	190	190	190	190	190	190	190	190	190	190	190
5	375	375	375	375	375	375	375	375	375	375	375	375
Total	1,483	1,483	1,483	1,483	1,483	1,483	1,483	1,483	1,483	1,483	1,483	1,483

Capacity in Dollars

Contract	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
1	[redacted]											
2												
3												
4												
5	7,325,264	7,325,264	7,325,264	7,325,264	7,325,264	7,325,264	7,325,264	7,325,264	7,325,264	7,325,264	7,325,264	7,325,264
Total	15,633,588	15,633,588	15,306,228	15,306,228	15,306,228	16,247,388	16,247,388	16,247,388	16,247,388	15,306,228	15,306,228	15,633,588

Total Capacity Payments to Non-Cogenerators for 2011	188,421,452	(1)

(1) Appendix III, Page 5, Line 1 - Capacity Payments to Non-Cogenerators

FLORIDA POWER & LIGHT COMPANY
RATE CASE ALLOCATION OF GAS TURBINE PRODUCTION REVENUE REQUIREMENT CAPPED AT FUEL SAVINGS
JUNE 2011 THROUGH DECEMBER 2011

	Rate (a)	Demand Component[1] (b)	Energy Component[2] (c)	Total Allocation (d)	Allocation (e)	WC3 Revenue Requirement Allocation Capped @ Fuel Savings (g)
1	CILC-1D	$17,493,455	$1,709,412	$19,202,867	2.3%	$2,232,846
2	CILC-1G	$1,176,140	$111,810	$1,287,950	0.2%	$149,759
3	CILC-1T	$8,080,885	$835,465	$8,916,350	1.1%	$1,036,764
4	CS1	$1,160,519	$105,520	$1,266,039	0.2%	$147,211
5	CS2	$428,835	$45,500	$474,335	0.1%	$55,154
6	GS1	$47,396,997	$3,392,474	$50,789,471	6.1%	$5,905,632
7	GSCU-1	$168,789	$18,278	$187,067	0.0%	$21,752
8	GSD1	$162,807,624	$13,183,528	$175,991,152	21.0%	$20,463,669
9	GSLD1	$36,949,374	$2,860,585	$39,809,959	4.8%	$4,628,970
10	GSLD2	$5,137,982	$461,595	$5,599,577	0.7%	$651,100
11	GSLD3	$1,347,888	$133,598	$1,481,486	0.2%	$172,262
12	HLFT1	$8,096,212	$796,670	$8,892,882	1.1%	$1,034,035
13	HLFT2	$32,350,533	$3,047,693	$35,398,226	4.2%	$4,115,989
14	HLFT3	$6,475,208	$642,403	$7,117,611	0.9%	$827,612
15	MET	$664,177	$51,396	$715,573	0.1%	$83,204
16	OL-1	$262,336	$58,296	$320,632	0.0%	$37,282
17	OS-2	$101,679	$7,470	$109,149	0.0%	$12,691
18	RS1	$438,692,056	$29,859,147	$468,551,203	56.0%	$54,481,583
19	SDTR-1	$3,247,106	$275,490	$3,522,596	0.4%	$409,596
20	SDTR-2	$3,778,319	$331,130	$4,109,449	0.5%	$477,833
21	SDTR-3	$398,066	$39,164	$437,230	0.1%	$50,840
22	SL-1	$1,353,505	$295,289	$1,648,794	0.2%	$191,716
23	SL-2	$161,439	$17,368	$178,807	0.0%	$20,791
24	SST-DST	$52,476	$4,022	$56,498	0.0%	$6,569
25	SST-TST	$466,203	$70,924	$537,127	0.1%	$62,455
26						
27	Total	$778,247,804	$58,354,225	$836,602,030	100.0%	$97,277,315

Notes:
1) E-6b of the Cost of Service Compliance Filing, line 9 pages 44 through 46
2) E-6b of the Cost of Service Compliance Filing, line 8 pages 47 through 49

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF REVENUE IMPACT FOR WEST COUNTY 3

	(a)	Total Revenue[1] (b)	Total Capacity Costs (c)		% Increase (d)
1	RS1/RST1	$5,446,960,664	$54,481,583		1.00%
2	GS1/GST1	$617,319,271	$5,905,632		0.96%
3	GSD1/GSDT1/HLFT1 (21-499 kW)	$2,182,489,602	$21,907,299		1.00%
4	OS2	$1,548,433	$12,691		0.82%
5	GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,99	$890,760,810	$9,370,003		1.05%
6	GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kV	$165,841,418	$1,584,706		0.96%
7	GSLD3/GSLDT3/CS3/CST3	$16,758,357	$172,262		1.03%
8	ISST1D	$0	$0		0.00%
9	ISST1T	$0	$0		0.00%
10	SST1T	$11,362,866	$62,455		0.55%
11	SST1D1/SST1D2/SST1D3	$783,503	$6,569		0.84%
12	CILC D/CILC G	$231,400,750	$2,382,604		1.03%
13	CILC T	$96,699,605	$1,036,764		1.07%
14	MET	$7,709,300	$83,204		1.08%
15	OL1/SL1/PL1	$111,332,796	$228,998		0.21%
16	SL2, GSCU1	$6,481,442	$42,543		0.66%
17					
18	TOTAL	$9,787,448,816	$97,277,315		0.99%
				1.5x	1.49%
				Max	1.08%

Notes
1) Based on 2011 Projections of base and clause revenues.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY RECOVERY FACTOR FOR WEST COUNTY 3
JUNE 2011 THROUGH DECEMBER 2011

	Rate Schedule	(1) Projected Sales at Meter (kwh)	(2) Billing kW Load Factor (%)	(3) Projected Billed kW at Meter (kw)	(4) Total Capacity Costs ($)	(5) Capacity Recovery Factor ($/kw)	(6) Capacity Recovery Factor ($/kwh)
1	RS1/RST1	32,529,803,873	-	-	$54,481,583	-	0.00167
2	GS1/GST1	3,705,625,063	-	-	$5,905,632	-	0.00159
3	GSD1/GSDT1/HLFT1 (21-499 kW)	15,647,481,371	48.67059%	44,040,774	$21,907,299	0.50	-
4	OS2	8,436,753	-	-	$12,691	-	0.00150
5	GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	7,013,546,323	63.68015%	15,087,273	$9,370,003	0.62	-
6	GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	1,323,364,078	68.37874%	2,651,157	$1,584,706	0.60	-
7	GSLD3/GSLDT3/CS3/CST3	152,349,039	73.56846%	283,678	$172,262	0.61	-
8	ISST1D	0	52.36474%	0	$0	**	-
9	ISST1T	0	14.03656%	0	$0	**	-
10	SST1T	80,898,930	14.03656%	789,513	$62,455	**	-
11	SST1D1/SST1D2/SST1D3	4,530,424	52.36474%	11,852	$6,569	**	-
12	CILC D/CILC G	2,018,667,964	74.83495%	3,695,196	$2,382,604	0.64	-
13	CILC T	955,077,422	81.55360%	1,604,252	$1,036,764	0.65	-
14	MET	57,810,792	59.46021%	133,186	$83,204	0.62	-
15	OL1/SL1/PL1	392,680,153	-	-	$228,998	-	0.00058
16	SL2, GSCU1	39,221,356	-	-	$42,543	-	0.00108
17							
18	TOTAL	63,929,493,542			$97,277,315		

(1) Projected kwh sales for the period June 2011 through December 2011
(2) Billing kW Load Factor based on 2010 data
(3) Calculated: Col(1)/(730 hours * Col(2))
(4) Per Rate Case Allocation Worksheet
(5) Calculated: Col (4) / Col (3)
(6) Calculated: Col (4) / Col (1)

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Demand Charge (RDD) = (Total col 4)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

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

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
ISST1D	$0.05	$0.02
ISST1T	$0.05	$0.02
SST1T	$0.05	$0.02
SST1D1/SST1D2/SST1D3	$0.05	$0.02

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF WEST COUNTY 3 CAPACITY RECOVERY FACTOR
JUNE 2011 - DECEMBER 2011

RATE SCHEDULE	Jan 2011- Dec 2011 Capacity Recovery Factor		WCEC-3 Capacity Recovery Factor		Total Capacity Recovery Factor Jun 2010-Dec 2010	
	($/kw)	($/kwh)	($/kw)	($/kwh)	($/kw)	($/kwh)
RS1/RST1	-	0.00655	-	0.00167	-	0.00822
GS1/GST1/WIES1	-	0.00625	-	0.00159	-	0.00784
GSD1/GSDT1/HLFT1 (21-499 kW)	1.96	-	0.50	-	2.46	-
OS2	-	0.00597	-	0.00150	-	0.00747
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	2.46	-	0.62	-	3.08	-
GSLD2/GSLDT2/CS2/CST2/HLFT3 (2,000+ kW)	2.38	-	0.60	-	2.98	-
GSLD3/GSLDT3/CS3/CST3	2.39	-	0.61	-	3.00	-
ISST1D	**	-	**	-	**	-
ISST1T	**	-	**	-	**	-
SST1T	**	-	**	-	**	-
SST1D1/SST1D2/SST1D3	**	-	**	-	**	-
CILC D/CILC G	2.55	-	0.64	-	3.19	-
CILC T	2.55	-	0.65	-	3.20	-
MET	2.47	-	0.62	-	3.09	-
OL1/SL1/PL1	-	0.00235	-	0.00058	-	0.00293
SL2/GSCU1	-	0.00430	-	0.00108	-	0.00538
TOTAL						

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF WEST COUNTY 3 CAPACITY RECOVERY FACTOR
JUNE 2011 - DECEMBER 2011

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

	Jan 2011- Dec 2011 Capacity Recovery Factor		WCEC-3 Capacity Recovery Factor		Total Capacity Recovery Factor Jun 2010-Dec 2010	
	RDC ** ($/kw)	SDD ** ($/kw)	RDC ** ($/kw)	SDD ** ($/kw)	RDC ** ($/kw)	SDD ** ($/kw)
ISST1D	$0.30	$0.14	$0.05	$0.02	$0.35	$0.16
ISST1T	$0.29	$0.14	$0.05	$0.02	$0.34	$0.16
SST1T	$0.29	$0.14	$0.05	$0.02	$0.34	$0.16
SST1D1/SST1D2/SST1D3	$0.30	$0.14	$0.05	$0.02	$0.35	$0.16

Demand Charge (RDD) = $\frac{\text{(Total Capacity Costs)/(Projected Avg 12 CP @gen)(.10) (demand loss expansion factor)}}{\text{12 months}}$

Sum of Daily Demand Charge (DDC) = $\frac{\text{(Total Capacity Costs)/(Projected Avg 12 CP @ gen)/(21 onpeak days) (demand loss expansion factor)}}{\text{12 months}}$

APPENDIX IV
FUEL COST RECOVERY

2011 E SCHEDULES
BASED ON STIPULATION AND SETTLEMENT AGREEMENT
FACTOR CALCULATON METHODOLOGY
AND EXCLUDING THE SCHERER UNIT 4 STEAM TURBINE UPGRADE

TJK-7
DOCKET NO. 100001-EI
FPL WITNESS: T.J. KEITH
EXHIBIT ____________
PAGES 1-17
SEPTEMBER 1, 2010

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2011 -MAY 2011

		(a) DOLLARS		(b) MWH	(c) ¢/KWH
1	Fuel Cost of System Net Generation (E3)	$3,918,477,328		100,446,655	3.9011
1a	West County Energy Center Unit 3 Savings	98,411,000		100,446,655	0.0980
2	Nuclear Fuel Disposal Costs (E2)	19,509,650		20,930,855	0.0932
3	Fuel Cost of Sales to FKEC / CKW (E2)	(45,215,546)		(974,289)	4.6409
4	TOTAL COST OF GENERATED POWER	$3,991,182,432		99,472,367	4.0124
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	222,436,193		6,404,103	3.4733
6	Energy Cost of Economy Purchases (Florida) (E9)	47,620,744		775,570	6.1401
7	Energy Cost of Economy Purchases (Non-Florida) (E9)	32,097,565		625,025	5.1354
8	Payments to Qualifying Facilities (E8)	153,332,683		4,073,261	3.7644
9	TOTAL COST OF PURCHASED POWER	$455,487,185		11,877,959	3.8347
10	TOTAL AVAILABLE KWH (LINE 6 + LINE 11)			111,350,326	
11	Fuel Cost of Economy Sales (E6)	(40,232,035)		(873,500)	4.6058
12	Gain on Economy Sales (E6)	(9,692,706)		(1,252,119)	0.7741
13	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(2,446,761)		(378,619)	0.6462
14	Fuel Cost of Other Power Sales (E6)	0		0	0.0000
15	TOTAL FUEL COST AND GAINS OF POWER SALES	($52,371,501)		(1,252,119)	4.1826
16	Net Inadvertent Interchange	0		0	
17	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 6 + 11 + 18)	$4,394,298,115		110,098,206	3.9913
18	Net Unbilled Sales	(25,913,146)	**	(649,248)	(0.0251)
19	Company Use	13,182,894	**	330,295	0.0128
20	T & D Losses	285,629,377	**	7,156,383	0.2766
21	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$4,394,298,115		103,260,777	4.2555
22	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$50,621,875		1,189,558	4.2555
23	Jurisdictional MWH Sales	$4,343,676,240		102,071,219	4.2555
24	Jurisdictional Loss Multiplier	-		-	1.00083
25	Jurisdictional MWH Sales Adjusted for Line Losses	$4,347,281,491		102,071,219	4.2591
26	FINAL TRUE-UP Jan 09- Dec 09 $8,771,414 underrecovery; EST/ACT TRUE-UP Jan 10 - Dec 10 $286,129,908 underrecovery	294,901,322		102,071,219	0.2889
27	TOTAL JURISDICTIONAL FUEL COST	$4,642,182,813		102,071,219	4.5480
28	Revenue Tax Factor				1.00072
29	Fuel Factor Adjusted for Taxes	4,645,525,185			4.5513
30	GPIF ***	$8,115,900		102,071,219	0.0080
31	Fuel Factor including GPIF (Line 32 + Line 33)	4,653,641,085		102,071,219	4.5593
32	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH				4.559

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

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2011 - MAY 2011

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	31.48	36.17
OFF PEAK	68.52	63.83
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$4,394,298,115	$1,589,417,499	$2,804,880,616
2	MWH SALES	103,260,777	32,508,973	70,751,804
3	COST PER KWH SOLD	4.2555	4.8892	3.9644
4	JURISDICTIONAL LOSS FACTOR	1.00083	1.00083	1.00083
5	JURISDICTIONAL FUEL FACTOR	4.2591	4.8932	3.9677
6	TRUE-UP	0.2889	0.2889	0.2889
7				
8	TOTAL	4.5480	5.1821	4.2566
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	4.5513	5.1858	4.2597
11	GPIF	0.0080	0.0080	0.0080
12	RECOVERY FACTOR including GPIF	4.5593	5.1938	4.2677
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.559	5.194	4.268

HOURS:		
	ON-PEAK	25.10 %
	OFF-PEAK	74.90 %

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E
Page 1 of 2

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

JANUARY 2011 - MAY 2011

(1) GROUP	(2) RATE SCHEDULE	(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh	4.559	1.00207	4.214
	all additional kWh	4.559	1.00207	5.214
A	GS-1, SL-2, GSCU-1, WIES-1	4.559	1.00207	4.569
A-1*	SL-1, OL-1, PL-1	4.416	1.00207	4.425
B	GSD-1	4.559	1.00202	4.568
C	GSLD-1 & CS-1	4.559	1.00116	4.565
D	GSLD-2, CS-2, OS-2 & MET	4.559	0.99426	4.533
E	GSLD-3 & CS-3	4.559	0.96229	4.387
A	RST-1, GST-1 ON-PEAK	5.194	1.00207	5.205
	OFF-PEAK	4.268	1.00207	4.277
B	GSDT-1, CILC-1(G), ON-PEAK	5.194	1.00201	5.204
	HLFT-1 (21-499 kW) OFF-PEAK	4.268	1.00201	4.276
C	GSLDT-1, CST-1, ON-PEAK	5.194	1.00127	5.200
	HLFT-2 (500-1,999 kW) OFF-PEAK	4.268	1.00127	4.273
D	GSLDT-2, CST-2, ON-PEAK	5.194	0.99552	5.171
	HLFT-3 (2,000+ kW) OFF-PEAI	4.268	0.99552	4.249
E	GSLDT-3,CST-3, ON-PEAK	5.194	0.96229	4.998
	CILC -1(T) OFF-PEAK & ISST-1(T)	4.268	0.96229	4.107
F	CILC -1(D) & ON-PEAK	5.194	0.99484	5.167
	ISST-1(D) OFF-PEAK	4.268	0.99484	4.246

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

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2011 - MAY 2011

LINE NO.		(a) JANUARY ESTIMATED	(b) FEBRUARY ESTIMATED	(c) MARCH ESTIMATED	(d) APRIL ESTIMATED	(e) MAY ESTIMATED	(f) JUNE ESTIMATED	(g) 6 MONTH SUB-TOTAL	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$282,465,430	$246,439,168	$277,867,113	$298,019,007	$343,936,505	$348,794,790	$1,797,522,011	1
2	NUCLEAR FUEL DISPOSAL	1,578,003	1,396,693	1,438,035	1,469,633	1,805,809	1,923,091	9,611,264	2
2a	WCEC UNIT 3 FUEL SAVINGS	8,200,917	8,200,917	8,200,917	8,200,917	8,200,917	8,200,917	49,205,500	2a
3	FUEL COST OF POWER SOLD	(6,746,669)	(8,210,258)	(5,030,664)	(2,391,451)	(1,574,033)	(1,659,181)	(25,612,255)	3
4	GAIN ON ECONOMY SALES	(1,823,390)	(1,923,974)	(1,132,972)	(365,649)	(233,823)	(256,730)	(5,736,539)	4
5	FUEL COST OF PURCHASED POWER	17,001,688	15,507,270	12,095,521	20,064,019	22,693,723	20,603,441	107,965,664	5
6	QUALIFYING FACILITIES	13,118,570	13,560,610	12,960,754	5,812,521	11,210,361	14,755,317	71,418,133	6
7	ENERGY COST OF ECONOMY PURCHASES	1,015,902	687,594	931,652	3,636,225	12,511,553	20,393,488	39,176,414	7
8	FUEL COST OF SALES TO FKEC / CKW	(3,215,041)	(3,149,627)	(3,244,019)	(3,571,096)	(3,862,515)	(4,190,308)	(21,232,605)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$311,595,411	$272,508,393	$304,086,339	$330,874,125	$394,688,496	$408,564,823	$2,022,317,587	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,264,331	7,246,664	7,396,703	7,356,403	8,317,721	9,362,714	47,944,537	10
11	COST PER KWH SOLD (¢/KWH)	3.7704	3.7605	4.1111	4.4978	4.7452	4.3637	4.2180	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	3.7735	3.7636	4.1145	4.5015	4.7491	4.3674	4.2215	13
14	TRUE-UP (¢/KWH)	0.3005	0.3434	0.3360	0.3382	0.2987	0.2655	0.3111	14
15	TOTAL	4.0740	4.1070	4.4505	4.8397	5.0478	4.6329	4.5326	15
16	REVENUE TAX FACTOR 0.00072	0.0029	0.0030	0.0032	0.0035	0.0036	0.0033	0.0033	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	4.0769	4.1100	4.4537	4.8432	5.0514	4.6362	4.5359	17
18	GPIF (¢/KWH)	0.0083	0.0094	0.0092	0.0093	0.0082	0.0073	0.0086	18
19	RECOVERY FACTOR including GPIF	4.0852	4.1194	4.4629	4.8525	5.0596	4.6435	4.5445	19
20	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	4.085	4.119	4.463	4.853	5.060	4.644	4.545	20

APPENDIX IV
BASED ON AGREEMENT METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2011 - MAY 2011

LINE NO.		(h) JULY ESTIMATED	(i) AUGUST ESTIMATED	(j) SEPTEMBER ESTIMATED	(k) OCTOBER ESTIMATED	(l) NOVEMBER ESTIMATED	(m) DECEMBER ESTIMATED	(n) 12 MONTH PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$387,813,785	$400,954,046	$395,820,616	$370,731,454	$288,661,681	$276,973,737	$3,918,477,328	1
2	NUCLEAR FUEL DISPOSAL	1,987,193	1,932,293	1,374,103	1,419,905	1,405,498	1,779,394	$19,509,650	2
2a	WCEC UNIT 3 FUEL SAVINGS	8,200,917	8,200,917	8,200,917	8,200,917	8,200,917	8,200,917	$98,411,000	2a
3	FUEL COST OF POWER SOLD	(2,287,013)	(2,822,926)	(1,290,210)	(2,233,840)	(3,057,590)	(5,374,962)	($42,678,796)	3
4	GAIN ON ECONOMY SALES	(332,757)	(483,027)	(160,097)	(329,025)	(955,689)	(1,695,572)	($9,692,706)	4
5	FUEL COST OF PURCHASED POWER	21,970,282	21,391,572	22,938,069	21,986,795	13,094,526	13,089,284	$222,436,193	5
6	QUALIFYING FACILITIES	15,911,682	15,591,655	15,824,779	12,152,957	7,906,070	14,527,407	$153,332,683	6
7	ENERGY COST OF ECONOMY PURCHASES	10,897,788	10,646,300	10,006,799	6,336,300	1,516,220	1,138,489	$79,718,309	7
8	FUEL COST OF SALES TO FKEC / CKW	(4,331,369)	(4,458,628)	(4,385,071)	(3,969,481)	(3,589,740)	(3,248,653)	($45,215,546)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$439,830,507	$450,952,202	$448,329,904	$414,295,983	$313,181,893	$305,390,040	$4,394,298,115	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	9,972,647	9,903,541	10,377,478	8,910,784	8,245,065	7,906,722	103,260,777	10
11	COST PER KWH SOLD (¢/KWH)	4.4104	4.5534	4.3202	4.6494	3.7984	3.8624	4.2555	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	4.4140	4.5572	4.3238	4.6532	3.8016	3.8656	4.2591	13
14	TRUE-UP (¢/KWH)	0.2491	0.2511	0.2396	0.2793	0.3018	0.3141	0.2889	14
15	TOTAL	4.6631	4.8083	4.5634	4.9325	4.1034	4.1797	4.5480	15
16	REVENUE TAX FACTOR 0.00072	0.0034	0.0035	0.0033	0.0036	0.0030	0.0030	0.0033	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	4.6665	4.8118	4.5667	4.9361	4.1064	4.1827	4.5513	17
18	GPIF (¢/KWH)	0.0069	0.0069	0.0066	0.0077	0.0083	0.0086	0.0080	18
19	RECOVERY FACTOR including GPIF	4.6734	4.8187	4.5733	4.9438	4.1147	4.1913	4.5593	19
20	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	4.673	4.819	4.573	4.944	4.115	4.191	4.559	20

APPENDIX IV
BASED ON AGREEMENT METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

2011	Jan-May			
	RS-1 standard	proposed inverted fuel factors	target fuel revenues	rounded
First 1000 kWh	36,523,505,744	0.04214114	1,539,142,158.12	4.214
All additional kWh	20,004,455,892	0.05214114	1,043,055,129.41	5.214
	56,527,961,636		2,582,197,287.53	
avg fuel factor	4.559			
RS-1 loss mult	1.00207		(0.00)	
average fuel Factor	4.568			
target fuel revenues	2,582,197,287.53			

APPENDIX IV
BASED ON AGREEMENT METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	NOV 10- DEC 10	PRELIMINARY JAN 11 - MAY 11	DIFFERENCE $	DIFFERENCE %
BASE	$43.01	$43.01	$0.00	0.00%
FUEL	$38.57	$42.14	$3.57	9.26%
CONSERVATION	$1.88	$3.64	$1.76	93.62%
CAPACITY PAYMENT	$6.21	$6.55	$0.34	5.48%
ENVIRONMENTAL	$1.79	$1.43	-$0.36	-20.11%
STORM RESTORATION SURCHARGE	$1.17	$1.17	$0.00	0.00%
SUBTOTAL	$92.63	$97.94	$5.31	5.73%
GROSS RECEIPTS TAX	$2.38	$2.51	$0.13	5.46%
TOTAL	**$95.01**	**$100.45**	$5.44	5.73%

APPENDIX IV
BASED ON AGREEMENT METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JUNE 2011 -DECEMBER 2011

		(a) DOLLARS	(b) MWH	(c) ¢/KWH
1	Fuel Cost of System Net Generation (E3)	$3,918,477,328	100,446,655	3.9011
1a	West County Energy Center Unit 3 Savings	98,411,000	100,446,655	0.0980
2	Nuclear Fuel Disposal Costs (E2)	19,509,650	20,930,855	0.0932
3	Fuel Cost of Sales to FKEC / CKW (E2)	(45,215,546)	(974,289)	4.6409
4	TOTAL COST OF GENERATED POWER	$3,991,182,432	99,472,367	4.0124
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	222,436,193	6,404,103	3.4733
6	Energy Cost of Economy Purchases (Florida) (E9)	47,620,744	775,570	6.1401
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8	Payments to Qualifying Facilities (E8)	153,332,683	4,073,261	3.7644
9	TOTAL COST OF PURCHASED POWER	$455,487,185	11,877,959	3.8347
10	TOTAL AVAILABLE KWH (LINE 6 + LINE 11)		111,350,326	
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12	Gain on Economy Sales (E6)	(9,692,706)	(1,252,119)	0.7741
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14	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
15	TOTAL FUEL COST AND GAINS OF POWER SALES	($52,371,501)	(1,252,119)	4.1826
16	Net Inadvertent Interchange	0	0	
17	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 6 + 11 + 16)	$4,394,298,115	110,098,206	3.9913
18	Net Unbilled Sales	(25,913,146) **	(649,248)	(0.0251)
19	Company Use	13,182,894 **	330,295	0.0128
20	T & D Losses	285,629,377 **	7,156,383	0.2766
21	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$4,394,298,115	103,260,777	4.2555
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23	Jurisdictional MWH Sales	$4,343,676,240	102,071,219	4.2555
24	Jurisdictional Loss Multiplier	-	-	1.00083
25	Jurisdictional MWH Sales Adjusted for Line Losses	$4,347,281,491	102,071,219	4.2591
26	FINAL TRUE-UP Jan 09- Dec 09 $8,771,414 underrecovery; EST/ACT TRUE-UP Jan 10 - Dec 10 $286,129,908 underrecovery	294,901,322	102,071,219	0.2889
27	TOTAL JURISDICTIONAL FUEL COST	$4,642,182,813	102,071,219	4.5480
28	Revenue Tax Factor			1.00072
29	Fuel Factor Adjusted for Taxes	4,645,525,185		4.5513
30	GPIF ***	$8,115,900	102,071,219	0.0080
33a	Jurisdictionalized WCEC Unit 3 Fuel Savings	($97,277,315)	63,929,494	(0.1523)
31	Fuel Factor including GPIF (Line 32 + Line 33)	4,556,363,770	102,071,219	4.4070
32	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			4.407

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

<u>Calculation of Jurisdictional Separation Factor</u>

WCEC Unit 3 Fuel Savings	$98,411,000
2011 Jurisdictional %	98.84801%
Jurisdictionalized WCEC Unit 3 Fuel Savings	$97,277,315

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D
Page 1 of 2

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JUNE 2011 - DECEMBER 2011

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	31.48	36.17
OFF PEAK	68.52	63.83
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$4,394,298,115	$1,589,417,499	$2,804,880,616
2	MWH SALES	103,260,777	32,508,973	70,751,804
3	COST PER KWH SOLD	4.2555	4.8892	3.9644
4	JURISDICTIONAL LOSS FACTOR	1.00083	1.00083	1.00083
5	JURISDICTIONAL FUEL FACTOR	4.2591	4.8932	3.9677
6	TRUE-UP	0.2889	0.2889	0.2889
7				
8	TOTAL	4.5480	5.1821	4.2566
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	4.5513	5.1858	4.2597
11	GPIF	0.0080	0.0080	0.0080
12	WCEC UNIT 3 FUEL SAVINGS	-0.1523	-0.1523	-0.1523
13	RECOVERY FACTOR including GPIF	4.4070	5.0415	4.1154
14	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.407	5.042	4.115

HOURS:	ON-PEAK	25.10	%
	OFF-PEAK	74.90	%

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2011 THROUGH SEPTEMBER 2011 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	24.30	28.83
OFF PEAK	75.70	71.17
	100.00	100.00

SDTR FUEL RECOVERY CALCULATION

	TOTAL	ON-PEAK	OFF-PEAK
1 TOTAL FUEL & NET POWER TRANS	$4,394,298,115	$1,266,958,027	$3,127,340,088
2 MWH SALES	103,260,777	25,089,710	78,171,067
3 COST PER KWH SOLD	4.2555	5.0497	4.0006
4 JURISDICTIONAL LOSS FACTOR	1.00083	1.00083	1.00083
5 JURISDICTIONAL FUEL FACTOR	4.2591	5.0539	4.0040
6 TRUE-UP	0.2889	0.2889	0.2889
7			
8 TOTAL	4.5480	5.3428	4.2929
9 REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10 SDTR RECOVERY FACTOR	4.5513	5.3466	4.2960
11 GPIF	0.0080	0.0080	0.0080
12 WCEC UNIT 3 FUEL SAVINGS	-0.1523	6.3553	5.3047
13 SDTR RECOVERY FACTOR including GPIF	4.4070	5.3546	4.3040
14 SDTR RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.407	5.355	4.304

HOURS:	ON-PEAK	19.67 %
	OFF-PEAK	80.33 %

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1D, Page 1 of 2.

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E
Page 1 of 2

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

JUNE 2011 - DECEMBER 2011

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh		4.407	1.00207	4.062
	all additional kWh		4.407	1.00207	5.062
A	GS-1, SL-2, GSCU-1, WIES-1		4.407	1.00207	4.416
A-1*	SL-1, OL-1, PL-1		4.264	1.00207	4.273
B	GSD-1		4.407	1.00202	4.416
C	GSLD-1 & CS-1		4.407	1.00116	4.412
D	GSLD-2, CS-2, OS-2 & MET		4.407	0.99426	4.382
E	GSLD-3 & CS-3		4.407	0.96229	4.241
A	RST-1, GST-1	ON-PEAK	5.042	1.00207	5.052
		OFF-PEAK	4.115	1.00207	4.124
B	GSDT-1, CILC-1(G),	ON-PEAK	5.042	1.00201	5.052
	HLFT-1 (21-499 kW)	OFF-PEAK	4.115	1.00201	4.124
C	GSLDT-1, CST-1,	ON-PEAK	5.042	1.00127	5.048
	HLFT-2 (500-1,999 kW)	OFF-PEAK	4.115	1.00127	4.121
D	GSLDT-2, CST-2,	ON-PEAK	5.042	0.99552	5.019
	HLFT-3 (2,000+ kW)	OFF-PEAI	4.115	0.99552	4.097
E	GSLDT-3,CST-3,	ON-PEAK	5.042	0.96229	4.851
	CILC -1(T) & ISST-1(T)	OFF-PEAK	4.115	0.96229	3.960
F	CILC -1(D) &	ON-PEAK	5.042	0.99484	5.015
	ISST-1(D)	OFF-PEAK	4.115	0.99484	4.094

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

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2011 THROUGH SEPTEMBER 2011 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

(1) GROUP	(2) OTHERWISE APPLICABLE RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) SDTR FUEL RECOVERY FACTOR
B	GSD(T)-1	ON-PEAK	5.355	1.00202	5.366
		OFF-PEAK	4.304	1.00202	4.313
C	GSLD(T)-1	ON-PEAK	5.355	1.00123	5.362
		OFF-PEAK	4.304	1.00123	4.309
D	GSLD(T)-2	ON-PEAK	5.355	0.99599	5.334
		OFF-PEAK	4.304	0.99599	4.287

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JUNE 2011 - DECEMBER 2011

SCHEDULE E2
Page 1 of 2

LINE NO.		(a) JANUARY ESTIMATED	(b) FEBRUARY ESTIMATED	(c) MARCH ESTIMATED	(d) APRIL ESTIMATED	(e) MAY ESTIMATED	(f) JUNE ESTIMATED	(g) 6 MONTH SUB-TOTAL	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$282,465,430	$246,439,168	$277,867,113	$298,019,007	$343,936,505	$348,794,790	$1,797,522,011	1
2	NUCLEAR FUEL DISPOSAL	1,578,003	1,396,693	1,438,035	1,469,633	1,805,809	1,923,091	9,611,264	2
2a	WCEC UNIT 3 SAVINGS	98,411,000	98,411,000	98,411,000	98,411,000	98,411,000	98,411,000	590,466,000	2a
3	FUEL COST OF POWER SOLD	(6,746,669)	(8,210,258)	(5,030,664)	(2,391,451)	(1,574,033)	(1,659,181)	(25,612,255)	3
4	GAIN ON ECONOMY SALES	(1,823,390)	(1,923,974)	(1,132,972)	(365,649)	(233,823)	(256,730)	(5,736,539)	4
5	FUEL COST OF PURCHASED POWER	17,001,688	15,507,270	12,095,521	20,064,019	22,693,723	20,603,441	107,965,664	5
6	QUALIFYING FACILITIES	13,118,570	13,560,610	12,960,754	5,812,521	11,210,361	14,755,317	71,418,133	6
7	ENERGY COST OF ECONOMY PURCHASES	1,015,902	687,594	931,652	3,636,225	12,511,553	20,393,488	39,176,414	7
8	FUEL COST OF SALES TO FKEC / CKW	(3,215,041)	(3,149,627)	(3,244,019)	(3,571,096)	(3,862,515)	(4,190,308)	(21,232,605)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$401,805,494	$362,718,477	$394,296,422	$421,084,209	$484,898,579	$498,774,907	$2,563,578,087	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,264,331	7,246,664	7,396,703	7,356,403	8,317,721	9,362,714	47,944,537	10
11	COST PER KWH SOLD (¢/KWH)	4.8619	5.0053	5.3307	5.7240	5.8297	5.3272	5.3470	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	4.8660	5.0095	5.3351	5.7288	5.8345	5.3317	5.3514	13
14	TRUE-UP (¢/KWH)	0.3005	0.3434	0.3360	0.3382	0.2987	0.2655	0.3111	14
15	TOTAL	5.1665	5.3529	5.6711	6.0670	6.1332	5.5972	5.6625	15
16	REVENUE TAX FACTOR 0.00072	0.0037	0.0039	0.0041	0.0044	0.0044	0.0040	0.0041	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	5.1702	5.3568	5.6752	6.0714	6.1376	5.6012	5.6666	17
18	GPIF (¢/KWH)	0.0083	0.0094	0.0092	0.0093	0.0082	0.0073	0.0086	18
19	JURISDICTIONALIZED SAVINGS-WCEC 3	0.0000	0.0000	0.0000	0.0000	0.0000	(0.1502)	(0.1502)	19
20	RECOVERY FACTOR including GPIF	5.1785	5.3662	5.6844	6.0807	6.1458	5.4583	5.5250	20
21	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	5.179	5.366	5.684	6.081	6.146	5.458	5.525	21

APPENDIX IV
BASED ON AGREEMENT METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JUNE 2011 - DECEMBER 2011

LINE NO.		(h) JULY ESTIMATED	(i) AUGUST ESTIMATED	(j) SEPTEMBER ESTIMATED	(k) OCTOBER ESTIMATED	(l) NOVEMBER ESTIMATED	(m) DECEMBER ESTIMATED	(n) 12 MONTH PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$387,813,785	$400,954,046	$395,820,616	$370,731,454	$288,661,681	$276,973,737	$3,918,477,328	1
2	NUCLEAR FUEL DISPOSAL	1,987,193	1,932,293	1,374,103	1,419,905	1,405,498	1,779,394	$19,509,650	2
2a	WCEC UNIT 3 SAVINGS	98,411,000	98,411,000	98,411,000	98,411,000	98,411,000	98,411,000	$98,411,000	2a
3	FUEL COST OF POWER SOLD	(2,287,013)	(2,822,926)	(1,290,210)	(2,233,840)	(3,057,590)	(5,374,962)	($42,678,796)	3
4	GAIN ON ECONOMY SALES	(332,757)	(483,027)	(160,097)	(329,025)	(955,689)	(1,695,572)	($9,692,706)	4
5	FUEL COST OF PURCHASED POWER	21,970,282	21,391,572	22,938,069	21,986,795	13,094,526	13,089,284	$222,436,193	5
6	QUALIFYING FACILITIES	15,911,682	15,591,655	15,824,779	12,152,957	7,906,070	14,527,407	$153,332,683	6
7	ENERGY COST OF ECONOMY PURCHASES	10,897,788	10,646,300	10,006,799	6,336,300	1,516,220	1,138,489	$79,718,309	7
8	FUEL COST OF SALES TO FKEC / CKW	(4,331,369)	(4,458,628)	(4,385,071)	(3,969,481)	(3,589,740)	(3,248,653)	($45,215,546)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$530,040,590	$541,162,285	$538,539,987	$504,506,066	$403,391,976	$395,600,124	$4,394,298,115	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	9,972,647	9,903,541	10,377,478	8,910,784	8,245,065	7,906,722	103,260,777	10
11	COST PER KWH SOLD (¢/KWH)	5.3149	5.4643	5.1895	5.6617	4.8925	5.0033	4.2555	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	5.3194	5.4689	5.1938	5.6664	4.8966	5.0075	4.2591	13
14	TRUE-UP (¢/KWH)	0.2491	0.2511	0.2396	0.2793	0.3018	0.3141	0.2889	14
15	TOTAL	5.5685	5.7200	5.4334	5.9457	5.1984	5.3216	4.5480	15
16	REVENUE TAX FACTOR 0.00072	0.0040	0.0041	0.0039	0.0043	0.0037	0.0038	0.0033	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	5.5725	5.7241	5.4373	5.9500	5.2021	5.3254	4.5513	17
18	GPIF (¢/KWH)	0.0069	0.0069	0.0066	0.0077	0.0083	0.0086	0.0080	18
19	JURISDICTIONALIZED SAVINGS-WCEC 3	(0.1410)	(0.1421)	(0.1356)	(0.1580)	(0.1708)	(0.1778)	(0.1523)	19
20	RECOVERY FACTOR including GPIF	5.4384	5.5889	5.3083	5.7997	5.0396	5.1562	4.4070	20
21	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	5.438	5.589	5.308	5.800	5.040	5.156	4.407	21

APPENDIX IV
BASED ON AGREEMENT METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

APPENDIX IV
BASED ON AGREEMENT METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

2011 Jun-Dec

	RS-1 standard	proposed inverted fuel factors	target fuel revenues	rounded
First 1000 kWh	36,523,505,744	0.04062114	1,483,626,429.39	4.062
All additional kWh	20,004,455,892	0.05062114	1,012,648,356.46	5.062
	56,527,961,636		$\boxed{2,496,274,785.85}$	
avg fuel factor	4.407			
RS-1 loss mult	1.00207		0.00	
average fuel Factor	4.416			
target fuel revenues	2,496,274,785.85			

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	NOV 10- DEC 10	PRELIMINARY JAN 11 - MAY 11	PRELIMINARY JUN 11 - DEC 11	DIFFERENCE CURRENT VS. JAN 11 $	DIFFERENCE CURRENT VS. JAN 11 %	DIFFERENCE JAN 11 VS. JUN 11 $	DIFFERENCE JAN 11 VS. JUN 11 %
BASE	$43.01	$43.01	$43.01	$0.00	0.00%	$0.00	0.00%
FUEL	$38.57	$42.14	$40.62	$3.57	9.26%	-$1.52	-3.61%
CONSERVATION	$1.88	$3.64	$3.64	$1.76	93.62%	$0.00	0.00%
CAPACITY PAYMENT	$6.21	$6.55	$8.22	$0.34	5.48%	$1.67	25.50%
ENVIRONMENTAL	$1.79	$1.43	$1.43	-$0.36	-20.11%	$0.00	0.00%
STORM RESTORATION SURCHARGE	$1.17	$1.17	$1.17	$0.00	0.00%	$0.00	0.00%
SUBTOTAL	$92.63	$97.94	$98.09	$5.31	5.73%	$0.15	0.15%
GROSS RECEIPTS TAX	$2.38	$2.51	$2.52	$0.13	5.46%	$0.01	0.40%
TOTAL	$95.01	$100.45	$100.61	$5.44	5.73%	$0.16	0.16%

APPENDIX IV
BASED ON AGREEMENT METHOD
EXCLUDING SCHERER UNIT 4 UPGRADE

APPENDIX V
FUEL COST RECOVERY

2011 E SCHEDULES
BASED ON STIPULATION AND SETTLEMENT AGREEMENT
FACTOR CALCULATION METHODOLOGY
AND INCLUDING THE SCHERER UNIT 4 STEAM TURBINE UPGRADE

TJK-8
DOCKET NO. 100001-EI
FPL WITNESS: T.J. KEITH
EXHIBIT ____________
PAGES 1-19
SEPTEMBER 1, 2010

APPENDIX V
BASED ON AGREEMENT METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2011 -MAY 2011

		(a)	(b)	(c)
		DOLLARS	MWH	¢/KWH
1	Fuel Cost of System Net Generation (E3)	$3,918,477,328	100,446,655	3.9011
1a	West County Energy Center Unit 3 Savings	98,411,000	100,446,655	0.0980
2	Nuclear Fuel Disposal Costs (E2)	19,509,650	20,930,855	0.0932
2a	Scherer Unit 4 Steam Turbine Upgrade	342,417	100,446,655	0.0003
3	Fuel Cost of Sales to FKEC / CKW (E2)	(45,215,546)	(974,289)	4.6409
4	TOTAL COST OF GENERATED POWER	$3,991,524,849	99,472,367	4.0127
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	222,436,193	6,404,103	3.4733
6	Energy Cost of Economy Purchases (Florida) (E9)	47,620,744	775,570	6.1401
7	Energy Cost of Economy Purchases (Non-Florida) (E9)	32,097,565	625,025	5.1354
8	Payments to Qualifying Facilities (E8)	153,332,683	4,073,261	3.7644
9	TOTAL COST OF PURCHASED POWER	$455,487,185	11,877,959	3.8347
10	TOTAL AVAILABLE KWH (LINE 6 + LINE 11)		111,350,326	
11	Fuel Cost of Economy Sales (E6)	(40,232,035)	(873,500)	4.6058
12	Gain on Economy Sales (E6)	(9,692,706)	(1,252,119)	0.7741
13	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(2,446,761)	(378,619)	0.6462
14	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
15	TOTAL FUEL COST AND GAINS OF POWER SALES	($52,371,501)	(1,252,119)	4.1826
16	Net Inadvertent Interchange	0	0	
17	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 6 + 11 + 16)	$4,394,640,532	110,098,206	3.9916
18	Net Unbilled Sales	(25,915,165) **	(649,248)	(0.0251)
19	Company Use	13,183,922 **	330,295	0.0128
20	T & D Losses	285,651,635 **	7,156,383	0.2766
21	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$4,394,640,532	103,260,777	4.2559
22	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$50,625,819	1,189,558	4.2559
23	Jurisdictional MWH Sales	$4,344,014,713	102,071,219	4.2559
24	Jurisdictional Loss Multiplier	-	-	1.00083
25	Jurisdictional MWH Sales Adjusted for Line Losses	$4,347,620,245	102,071,219	4.2594
26	FINAL TRUE-UP Jan 09- Dec 09 $8,771,414 underrecovery; EST/ACT TRUE-UP Jan 10 - Dec 10 $286,129,908 underrecovery	294,901,322	102,071,219	0.2889
27	TOTAL JURISDICTIONAL FUEL COST	$4,642,521,567	102,071,219	4.5483
28	Revenue Tax Factor			1.00072
29	Fuel Factor Adjusted for Taxes	4,645,864,183		4.5516
30	GPIF ***	$8,115,900	102,071,219	0.0080
31	Fuel Factor Including GPIF (Line 32 + Line 33)	4,653,980,083	102,071,219	4.5596
32	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			4.560

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

Florida Power & Light Company
Fuel Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer 4 Turbine Upgrade
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$4,495,445	$4,495,445
	c. Retirements / Reserve activities		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	0	4,495,445	n/a
3.	Less: Accumulated Depreciation	$0	0	0	0	0	0	4,870	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$4,490,575	n/a
6.	Average Net Investment		0	0	0	0	0	2,245,287	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		0	0	0	0	0	14,323	$14,323
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		0	0	0	0	0	3,644	$3,644
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	4,870	$4,870
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$22,836	$22,836

Notes:
(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages XX-XX.
(B) Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt component of 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages XX-XX.
(F) Applicable amortization period(s). See Form 42-8A, pages XX-XX.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

3

APPENDIX V
BASED ON AGREEMENT METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

Florida Power & Light Company
Fuel Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer 4 Turbine Upgrade
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$985,044	$0	$0	$0	$0	$5,480,489
	c. Retirements / Reserve activities		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$4,495,445	4,495,445	5,480,489	5,480,489	5,480,489	5,480,489	5,480,489	n/a
3.	Less: Accumulated Depreciation	$4,870	15,677	27,552	39,426	51,301	63,175	75,049	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,490,575	$4,479,768	$5,452,937	$5,441,063	$5,429,189	$5,417,314	$5,405,440	n/a
6.	Average Net Investment		4,485,171	4,966,352	5,447,000	5,435,126	5,423,251	5,411,377	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		28,611	31,680	34,746	34,671	34,595	34,519	213,145
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		7,279	8,059	8,839	8,820	8,801	8,782	54,224
8.	Investment Expenses								
	a. Depreciation (E)		10,807	11,874	11,874	11,874	11,874	11,874	75,049
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$46,697	$51,614	$55,460	$55,365	$55,270	$55,175	$342,418

Notes:
(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages XX-XX.
(B) Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt component of 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages XX-XX.
(F) Applicable amortization period(s). See Form 42-8A, pages XX-XX.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

APPENDIX V
BASED ON AGREEMENT METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D
Page 1 of 2

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2011 - MAY 2011

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	31.48	36.17
OFF PEAK	68.52	63.83
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$4,394,640,532	$1,589,541,351	$2,805,099,181
2	MWH SALES	103,260,777	32,508,973	70,751,804
3	COST PER KWH SOLD	4.2559	4.8895	3.9647
4	JURISDICTIONAL LOSS FACTOR	1.00083	1.00083	1.00083
5	JURISDICTIONAL FUEL FACTOR	4.2594	4.8936	3.9680
6	TRUE-UP	0.2889	0.2889	0.2889
7				
8	TOTAL	4.5483	5.1825	4.2569
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	4.5516	5.1862	4.2600
11	GPIF	0.0080	0.0080	0.0080
12	RECOVERY FACTOR including GPIF	4.5596	5.1942	4.2680
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.560	5.194	4.268

HOURS:		
	ON-PEAK	25.10 %
	OFF-PEAK	74.90 %

FLORIDA POWER & LIGHT COMPANY

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

JANUARY 2011 - MAY 2011

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh		4.560	1.00207	4.215
	all additional kWh		4.560	1.00207	5.215
A	GS-1, SL-2, GSCU-1, WIES-1		4.560	1.00207	4.569
A-1*	SL-1, OL-1, PL-1		4.416	1.00207	4.425
B	GSD-1		4.560	1.00202	4.569
C	GSLD-1 & CS-1		4.560	1.00116	4.565
D	GSLD-2, CS-2, OS-2 & MET		4.560	0.99426	4.533
E	GSLD-3 & CS-3		4.560	0.96229	4.388
A	RST-1, GST-1	ON-PEAK	5.194	1.00207	5.205
		OFF-PEAK	4.268	1.00207	4.277
B	GSDT-1, CILC-1(G),	ON-PEAK	5.194	1.00201	5.205
	HLFT-1 (21-499 kW)	OFF-PEAK	4.268	1.00201	4.277
C	GSLDT-1, CST-1,	ON-PEAK	5.194	1.00127	5.201
	HLFT-2 (500-1,999 kW)	OFF-PEAK	4.268	1.00127	4.273
D	GSLDT-2, CST-2,	ON-PEAK	5.194	0.99552	5.171
	HLFT-3 (2,000+ kW)	OFF-PEAK	4.268	0.99552	4.249
E	GSLDT-3,CST-3,	ON-PEAK	5.194	0.96229	4.998
	CILC -1(T) & ISST-1(T)	OFF-PEAK	4.268	0.96229	4.107
F	CILC -1(D) &	ON-PEAK	5.194	0.99484	5.167
	ISST-1(D)	OFF-PEAK	4.268	0.99484	4.246

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

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2011 - MAY 2011

SCHEDULE E2
Page 1 of 2

LINE NO.		(a) JANUARY ESTIMATED	(b) FEBRUARY ESTIMATED	(c) MARCH ESTIMATED	(d) APRIL ESTIMATED	(e) MAY ESTIMATED	(f) JUNE ESTIMATED	(g) 6 MONTH SUB-TOTAL	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$282,465,430	$246,439,168	$277,867,113	$298,019,007	$343,936,505	$348,794,790	$1,797,522,011	1
2	NUCLEAR FUEL DISPOSAL	1,578,003	1,396,693	1,438,035	1,469,633	1,805,809	1,923,091	9,611,264	2
2a	WCEC UNIT 3 FUEL SAVINGS	8,200,917	8,200,917	8,200,917	8,200,917	8,200,917	8,200,917	49,205,500	2a
2b	SCHERER UNIT 4 STEAM TURBINE UPGRADE	0	0	0	0	0	22,836	22,836	1d
3	FUEL COST OF POWER SOLD	(6,746,669)	(8,210,258)	(5,030,664)	(2,391,451)	(1,574,033)	(1,659,181)	(25,612,255)	3
4	GAIN ON ECONOMY SALES	(1,823,390)	(1,923,974)	(1,132,972)	(365,649)	(233,823)	(256,730)	(5,736,539)	4
5	FUEL COST OF PURCHASED POWER	17,001,688	15,507,270	12,095,521	20,064,019	22,693,723	20,603,441	107,965,664	5
6	QUALIFYING FACILITIES	13,118,570	13,560,610	12,960,754	5,812,521	11,210,361	14,755,317	71,418,133	6
7	ENERGY COST OF ECONOMY PURCHASES	1,015,902	687,594	931,652	3,636,225	12,511,553	20,393,488	39,176,414	7
8	FUEL COST OF SALES TO FKEC / CKW	(3,215,041)	(3,149,627)	(3,244,019)	(3,571,096)	(3,862,515)	(4,190,308)	(21,232,605)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$311,595,411	$272,508,393	$304,086,339	$330,874,125	$394,688,496	$408,587,659	$2,022,340,423	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,264,331	7,246,664	7,396,703	7,356,403	8,317,721	9,362,714	47,944,537	10
11	COST PER KWH SOLD (¢/KWH)	3.7704	3.7605	4.1111	4.4978	4.7452	4.3640	4.2181	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	3.7735	3.7636	4.1145	4.5015	4.7491	4.3676	4.2216	13
14	TRUE-UP (¢/KWH)	0.3005	0.3434	0.3360	0.3382	0.2987	0.2655	0.3111	14
15	TOTAL	4.0740	4.1070	4.4505	4.8397	5.0478	4.6331	4.5327	15
16	REVENUE TAX FACTOR 0.00072	0.0029	0.0030	0.0032	0.0035	0.0036	0.0033	0.0033	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	4.0769	4.1100	4.4537	4.8432	5.0514	4.6364	4.5360	17
18	GPIF (¢/KWH)	0.0083	0.0094	0.0092	0.0093	0.0082	0.0073	0.0086	18
19	RECOVERY FACTOR including GPIF	4.0852	4.1194	4.4629	4.8525	5.0596	4.6437	4.5446	19
20	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	4.085	4.119	4.463	4.853	5.060	4.644	4.545	20

APPENDIX V
BASED ON AGREEMENT METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2011 - MAY 2011

LINE NO.		(h) JULY ESTIMATED	(i) AUGUST ESTIMATED	(j) SEPTEMBER ESTIMATED	(k) OCTOBER ESTIMATED	(l) NOVEMBER ESTIMATED	(m) DECEMBER ESTIMATED	(n) 12 MONTH PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$387,813,785	$400,954,046	$395,820,616	$370,731,454	$288,661,681	$276,973,737	$3,918,477,328	1
2	NUCLEAR FUEL DISPOSAL	1,987,193	1,932,293	1,374,103	1,419,905	1,405,498	1,779,394	$19,509,650	2
2a	WCEC UNIT 3 FUEL SAVINGS	8,200,917	8,200,917	8,200,917	8,200,917	8,200,917	8,200,917	$98,411,000	2a
2b	SCHERER UNIT 4 STEAM TURBINE UPGRADE	46,697	51,614	55,460	55,365	55,270	55,175	$342,417	1d
3	FUEL COST OF POWER SOLD	(2,287,013)	(2,822,926)	(1,290,210)	(2,233,840)	(3,057,590)	(5,374,962)	($42,678,796)	3
4	GAIN ON ECONOMY SALES	(332,757)	(483,027)	(160,097)	(329,025)	(955,689)	(1,695,572)	($9,692,706)	4
5	FUEL COST OF PURCHASED POWER	21,970,282	21,391,572	22,938,069	21,986,795	13,094,526	13,089,284	$222,436,193	5
6	QUALIFYING FACILITIES	15,911,682	15,591,655	15,824,779	12,152,957	7,906,070	14,527,407	$153,332,683	6
7	ENERGY COST OF ECONOMY PURCHASES	10,897,788	10,646,300	10,006,799	6,336,300	1,516,220	1,138,489	$79,718,309	7
8	FUEL COST OF SALES TO FKEC / CKW	(4,331,369)	(4,458,628)	(4,385,071)	(3,969,481)	(3,589,740)	(3,248,653)	($45,215,546)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$439,877,204	$451,003,816	$448,385,364	$414,351,348	$313,237,163	$305,445,215	$4,394,640,532	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	9,972,647	9,903,541	10,377,478	8,910,784	8,245,065	7,906,722	103,260,777	10
11	COST PER KWH SOLD (¢/KWH)	4.4108	4.5540	4.3208	4.6500	3.7991	3.8631	4.2559	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	4.4145	4.5577	4.3243	4.6539	3.8022	3.8663	4.2594	13
14	TRUE-UP (¢/KWH)	0.2491	0.2511	0.2396	0.2793	0.3018	0.3141	0.2889	14
15	TOTAL	4.6636	4.8088	4.5639	4.9332	4.1040	4.1804	4.5483	15
16	REVENUE TAX FACTOR 0.00072	0.0034	0.0035	0.0033	0.0036	0.0030	0.0030	0.0033	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	4.6670	4.8123	4.5672	4.9368	4.1070	4.1834	4.5516	17
18	GPIF (¢/KWH)	0.0069	0.0069	0.0066	0.0077	0.0083	0.0086	0.0080	18
19	RECOVERY FACTOR including GPIF	4.6739	4.8192	4.5738	4.9445	4.1153	4.1920	4.5596	19
20	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	4.674	4.819	4.574	4.945	4.115	4.192	4.560	20

APPENDIX V
BASED ON AGREEMENT METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

2011 Jan-May	RS-1 standard	proposed inverted fuel factors	target fuel revenues	rounded
First 1000 kWh	36,523,505,744	0.04215114	1,539,507,393.18	4.215
All additional kWh	20,004,455,892	0.05215114	1,043,255,173.97	5.215
	56,527,961,636		2,582,762,567.15	
avg fuel factor	4.560			
RS-1 loss mult	1.00207		0.00	
average fuel Factor	4.569			
target fuel revenues	2,582,762,567.15			

APPENDIX V
BASED ON AGREEMENT METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

COMPANY: FLORIDA POWER & LIGHT COMPANY **SCHEDULE E10**

	NOV 10- DEC 10	PRELIMINARY JAN 11 - MAY 11	DIFFERENCE $	DIFFERENCE %
BASE	$43.01	$43.01	$0.00	0.00%
FUEL	$38.57	$42.15	$3.58	9.28%
CONSERVATION	$1.88	$3.64	$1.76	93.62%
CAPACITY PAYMENT	$6.21	$6.55	$0.34	5.48%
ENVIRONMENTAL	$1.79	$1.43	-$0.36	-20.11%
STORM RESTORATION SURCHARGE	$1.17	$1.17	$0.00	0.00%
SUBTOTAL	$92.63	$97.95	$5.32	5.74%
GROSS RECEIPTS TAX	$2.38	$2.51	$0.13	5.46%
TOTAL	**$95.01**	**$100.46**	$5.45	5.74%

BASED ON AGREEMENT METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JUNE 2011 -DECEMBER 2011

		(a) DOLLARS		(b) MWH	(c) ¢/KWH
1	Fuel Cost of System Net Generation (E3)	$3,918,477,328		100,446,655	3.9011
1a	West County Energy Center Unit 3 Savings	98,411,000		100,446,655	0.0980
2	Nuclear Fuel Disposal Costs (E2)	19,509,650		20,930,855	0.0932
2a	Scherer Unit 4 Steam Turbine Upgrade	342,417		0	0.0000
3	Fuel Cost of Sales to FKEC / CKW (E2)	(45,215,546)		(974,289)	4.6409
4	TOTAL COST OF GENERATED POWER	$3,991,524,849		99,472,367	4.0127
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	222,436,193		6,404,103	3.4733
6	Energy Cost of Economy Purchases (Florida) (E9)	47,620,744		775,570	6.1401
7	Energy Cost of Economy Purchases (Non-Florida) (E9)	32,097,565		625,025	5.1354
8	Payments to Qualifying Facilities (E8)	153,332,683		4,073,261	3.7844
9	TOTAL COST OF PURCHASED POWER	$455,487,185		11,877,959	3.8347
10	TOTAL AVAILABLE KWH (LINE 6 + LINE 11)			111,350,326	
11	Fuel Cost of Economy Sales (E6)	(40,232,035)		(873,500)	4.6058
12	Gain on Economy Sales (E6)	(9,692,706)		(1,252,119)	0.7741
13	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(2,446,761)		(378,619)	0.6462
14	Fuel Cost of Other Power Sales (E6)	0		0	0.0000
15	TOTAL FUEL COST AND GAINS OF POWER SALES	($52,371,501)		(1,252,119)	4.1826
16	Net Inadvertent Interchange	0		0	
17	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 6 + 11 + 18)	$4,394,640,532		110,098,206	3.9916
18	Net Unbilled Sales	(25,916,165)	**	(649,248)	(0.0251)
19	Company Use	13,183,922	**	330,295	0.0128
20	T & D Losses	285,651,635	**	7,156,383	0.2766
21	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$4,394,640,532		103,260,777	4.2559
22	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$50,625,819		1,189,558	4.2559
23	Jurisdictional MWH Sales	$4,344,014,713		102,071,219	4.2559
24	Jurisdictional Loss Multiplier	-		-	1.00083
25	Jurisdictional MWH Sales Adjusted for Line Losses	$4,347,620,245		102,071,219	4.2594
26	FINAL TRUE-UP Jan 09- Dec 09 $8,771,414 underrecovery; EST/ACT TRUE-UP Jan 10 - Dec 10 $286,129,908 underrecovery	294,901,322		102,071,219	0.2889
27	TOTAL JURISDICTIONAL FUEL COST	$4,642,521,567		102,071,219	4.5483
28	Revenue Tax Factor				1.00072
29	Fuel Factor Adjusted for Taxes	4,645,864,183			4.5516
30	GPIF ***	$8,115,900		102,071,219	0.0080
33a	Jurisdictionalized WCEC Unit 3 Fuel Savings	($97,277,315)		63,929,494	(0.1523)
31	Fuel Factor including GPIF (Line 32 + Line 33)	4,556,702,768		102,071,219	4.4073
32	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH				4.407

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

<u>Calculation of Jurisdictional Separation Factor</u>

WCEC Unit 3 Fuel Savings	$98,411,000
2011 Jurisdictional %	98.84801%
Jurisdictionalized WCEC Unit 3 Fuel Savings	$97,277,315

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JUNE 2011 - DECEMBER 2011

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	31.48	36.17
OFF PEAK	68.52	63.83
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$4,394,640,532	$1,589,541,351	$2,805,099,181
2	MWH SALES	103,260,777	32,508,973	70,751,804
3	COST PER KWH SOLD	4.2559	4.8895	3.9647
4	JURISDICTIONAL LOSS FACTOR	1.00083	1.00083	1.00083
5	JURISDICTIONAL FUEL FACTOR	4.2594	4.8936	3.9680
6	TRUE-UP	0.2889	0.2889	0.2889
7				
8	TOTAL	4.5483	5.1825	4.2569
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	4.5516	5.1862	4.2600
11	GPIF	0.0080	0.0080	0.0080
12	WCEC UNIT 3 FUEL SAVINGS	-0.1523	-0.1523	-0.1523
13	RECOVERY FACTOR including GPIF	4.4073	5.0419	4.1157
14	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.407	5.042	4.116

HOURS:	ON-PEAK	25.10 %
	OFF-PEAK	74.90 %

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2011 THROUGH SEPTEMBER 2011 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	24.30	28.83
OFF PEAK	75.70	71.17
	100.00	100.00

SDTR FUEL RECOVERY CALCULATION

	TOTAL	ON-PEAK	OFF-PEAK
1 TOTAL FUEL & NET POWER TRANS	$4,394,640,532	$1,267,056,752	$3,127,583,780
2 MWH SALES	103,260,777	25,089,710	78,171,067
3 COST PER KWH SOLD	4.2559	5.0501	4.0009
4 JURISDICTIONAL LOSS FACTOR	1.00083	1.00083	1.00083
5 JURISDICTIONAL FUEL FACTOR	4.2594	5.0543	4.0043
6 TRUE-UP	0.2889	0.2889	0.2889
7			
8 TOTAL	4.5483	5.3432	4.2932
9 REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10 SDTR RECOVERY FACTOR	4.5516	5.3470	4.2963
11 GPIF	0.0080	0.0080	0.0080
12 WCEC UNIT 3 FUEL SAVINGS	-0.1523	6.3557	5.3050
13 SDTR RECOVERY FACTOR including GPIF	4.4073	5.3550	4.3043
14 SDTR RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.407	5.355	4.304

HOURS:		
HOURS:	ON-PEAK	19.67 %
	OFF-PEAK	80.33 %

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1D, Page 1 of 2.

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E
Page 1 of 2

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

JUNE 2011 - DECEMBER 2011

(1) GROUP	(2) RATE SCHEDULE	(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh	4.407	1.00207	4.062
	all additional kWh	4.407	1.00207	5.062
A	GS-1, SL-2, GSCU-1, WIES-1	4.407	1.00207	4.416
A-1*	SL-1, OL-1, PL-1	4.264	1.00207	4.273
B	GSD-1	4.407	1.00202	4.416
C	GSLD-1 & CS-1	4.407	1.00116	4.412
D	GSLD-2, CS-2, OS-2 & MET	4.407	0.99426	4.382
E	GSLD-3 & CS-3	4.407	0.96229	4.241
A	RST-1, GST-1 ON-PEAK	5.042	1.00207	5.052
	OFF-PEAK	4.116	1.00207	4.124
B	GSDT-1, CILC-1(G), ON-PEAK	5.042	1.00201	5.052
	HLFT-1 (21-499 kW) OFF-PEAK	4.116	1.00201	4.124
C	GSLDT-1, CST-1, ON-PEAK	5.042	1.00127	5.048
	HLFT-2 (500-1,999 kW) OFF-PEAK	4.116	1.00127	4.121
D	GSLDT-2, CST-2, ON-PEAK	5.042	0.99552	5.019
	HLFT-3 (2,000+ kW) OFF-PEAI	4.116	0.99552	4.097
E	GSLDT-3,CST-3, ON-PEAK	5.042	0.96229	4.852
	CILC -1(T) OFF-PEAK & ISST-1(T)	4.116	0.96229	3.960
F	CILC -1(D) & ON-PEAK	5.042	0.99484	5.016
	ISST-1(D) OFF-PEAK	4.116	0.99484	4.094

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

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2011 THROUGH SEPTEMBER 2011 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

(1) GROUP	(2) OTHERWISE APPLICABLE RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) SDTR FUEL RECOVERY FACTOR
B	GSD(T)-1	ON-PEAK	5.355	1.00202	5.366
		OFF-PEAK	4.304	1.00202	4.313
C	GSLD(T)-1	ON-PEAK	5.355	1.00123	5.362
		OFF-PEAK	4.304	1.00123	4.309
D	GSLD(T)-2	ON-PEAK	5.355	0.99599	5.334
		OFF-PEAK	4.304	0.99599	4.287

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JUNE 2011 - DECEMBER 2011

LINE NO.		(a) JANUARY ESTIMATED	(b) FEBRUARY ESTIMATED	(c) MARCH ESTIMATED	(d) APRIL ESTIMATED	(e) MAY ESTIMATED	(f) JUNE ESTIMATED	(g) 6 MONTH SUB-TOTAL	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$282,465,430	$246,439,168	$277,867,113	$298,019,007	$343,936,505	$348,794,790	$1,797,522,011	1
2	NUCLEAR FUEL DISPOSAL	1,578,003	1,396,693	1,438,035	1,469,633	1,805,809	1,923,091	9,611,264	2
2a	WCEC UNIT 3 SAVINGS	98,411,000	98,411,000	98,411,000	98,411,000	98,411,000	98,411,000	590,466,000	2a
2b	SCHERER UNIT 4 STEAM TURBINE UPGRADE	0	0	0	0	0	22,836	22,836	2b
3	FUEL COST OF POWER SOLD	(6,746,669)	(8,210,258)	(5,030,664)	(2,391,451)	(1,574,033)	(1,659,181)	(25,612,255)	3
4	GAIN ON ECONOMY SALES	(1,823,390)	(1,923,974)	(1,132,972)	(365,649)	(233,823)	(256,730)	(5,736,539)	4
5	FUEL COST OF PURCHASED POWER	17,001,688	15,507,270	12,095,521	20,064,019	22,693,723	20,603,441	107,965,664	5
6	QUALIFYING FACILITIES	13,118,570	13,560,610	12,960,754	5,812,521	11,210,361	14,755,317	71,418,133	6
7	ENERGY COST OF ECONOMY PURCHASES	1,015,902	687,594	931,652	3,636,225	12,511,553	20,393,488	39,176,414	7
8	FUEL COST OF SALES TO FKEC / CKW	(3,215,041)	(3,149,627)	(3,244,019)	(3,571,096)	(3,862,515)	(4,190,308)	(21,232,605)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$401,805,494	$362,718,477	$394,296,422	$421,084,209	$484,898,579	$498,797,743	$2,563,600,923	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,264,331	7,246,664	7,396,703	7,356,403	8,317,721	9,362,714	47,944,537	10
11	COST PER KWH SOLD (¢/KWH)	4.8619	5.0053	5.3307	5.7240	5.8297	5.3275	5.3470	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	4.8660	5.0095	5.3351	5.7288	5.8345	5.3319	5.3515	13
14	TRUE-UP (¢/KWH)	0.3005	0.3434	0.3360	0.3382	0.2987	0.2655	0.3111	14
15	TOTAL	5.1665	5.3529	5.6711	6.0670	6.1332	5.5974	5.6626	15
16	REVENUE TAX FACTOR 0.00072	0.0037	0.0039	0.0041	0.0044	0.0044	0.0040	0.0041	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	5.1702	5.3568	5.6752	6.0714	6.1376	5.6014	5.6667	17
18	GPIF (¢/KWH)	0.0083	0.0094	0.0092	0.0093	0.0082	0.0073	0.0086	18
19	JURISDICTIONALIZED SAVINGS-WCEC 3	0.0000	0.0000	0.0000	0.0000	0.0000	(0.1502)	(0.1502)	19
20	RECOVERY FACTOR including GPIF	5.1785	5.3662	5.6844	6.0807	6.1458	5.4585	5.5251	20
21	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	5.179	5.366	5.684	6.081	6.146	5.459	5.525	21

APPENDIX V
BASED ON AGREEMENT METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JUNE 2011 - DECEMBER 2011

LINE NO.		(h) JULY ESTIMATED	(i) AUGUST ESTIMATED	(j) SEPTEMBER ESTIMATED	(k) OCTOBER ESTIMATED	(l) NOVEMBER ESTIMATED	(m) DECEMBER ESTIMATED	(n) 12 MONTH PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION	$387,813,785	$400,954,046	$395,820,616	$370,731,454	$288,661,681	$276,973,737	$3,918,477,328	1
2	NUCLEAR FUEL DISPOSAL	1,987,193	1,932,293	1,374,103	1,419,905	1,405,498	1,779,394	$19,509,650	2
2a	WCEC UNIT 3 SAVINGS	98,411,000	98,411,000	98,411,000	98,411,000	98,411,000	98,411,000	$98,411,000	2a
2b	SCHERER UNIT 4 STEAM TURBINE UPGRADE	46,697	51,614	55,460	55,365	55,270	55,175	$342,417	2b
3	FUEL COST OF POWER SOLD	(2,287,013)	(2,822,926)	(1,290,210)	(2,233,840)	(3,057,590)	(5,374,962)	($42,678,796)	3
4	GAIN ON ECONOMY SALES	(332,757)	(483,027)	(160,097)	(329,025)	(955,689)	(1,695,572)	($9,692,706)	4
5	FUEL COST OF PURCHASED POWER	21,970,282	21,391,572	22,938,069	21,986,795	13,094,526	13,089,284	$222,436,193	5
6	QUALIFYING FACILITIES	15,911,682	15,591,655	15,824,779	12,152,957	7,906,070	14,527,407	$153,332,683	6
7	ENERGY COST OF ECONOMY PURCHASES	10,897,788	10,646,300	10,006,799	6,336,300	1,516,220	1,138,489	$79,718,309	7
8	FUEL COST OF SALES TO FKEC / CKW	(4,331,369)	(4,458,628)	(4,385,071)	(3,969,481)	(3,589,740)	(3,248,653)	($45,215,546)	8
9	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$530,087,287	$541,213,899	$538,595,447	$504,561,431	$403,447,246	$395,655,299	$4,394,640,532	9
10	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	9,972,647	9,903,541	10,377,478	8,910,784	8,245,065	7,906,722	103,260,777	10
11	COST PER KWH SOLD (¢/KWH)	5.3154	5.4649	5.1900	5.6624	4.8932	5.0040	4.2559	11
12	JURISDICTIONAL LOSS MULTIPLIER	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	12
13	JURISDICTIONAL COST (¢/KWH)	5.3198	5.4694	5.1943	5.6671	4.8973	5.0082	4.2594	13
14	TRUE-UP (¢/KWH)	0.2491	0.2511	0.2396	0.2793	0.3018	0.3141	0.2889	14
15	TOTAL	5.5689	5.7205	5.4339	5.9464	5.1991	5.3223	4.5483	15
16	REVENUE TAX FACTOR 0.00072	0.0040	0.0041	0.0039	0.0043	0.0037	0.0038	0.0033	16
17	RECOVERY FACTOR ADJUSTED FOR TAXES	5.5729	5.7246	5.4378	5.9507	5.2028	5.3261	4.5516	17
18	GPIF (¢/KWH)	0.0069	0.0069	0.0066	0.0077	0.0083	0.0086	0.0080	18
19	JURISDICTIONALIZED SAVINGS-WCEC 3	(0.1410)	(0.1421)	(0.1356)	(0.1580)	(0.1708)	(0.1778)	(0.1523)	19
20	RECOVERY FACTOR including GPIF	5.4388	5.5894	5.3088	5.8004	5.0403	5.1569	4.4073	20
21	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	5.439	5.589	5.309	5.800	5.040	5.157	4.407	21

APPENDIX V
BASED ON AGREEMENT METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

2011 Jun-Dec

	RS-1 standard	proposed inverted fuel factors	target fuel revenues	rounded
First 1000 kWh	36,523,505,744	0.04062114	1,483,626,429.39	4.062
All additional kWh	20,004,455,892	0.05062114	1,012,648,356.46	5.062
	56,527,961,636		2,496,274,785.85	
avg fuel factor	4.407			
RS-1 loss mult	1.00207		0.00	
average fuel Factor	4.416			
target fuel revenues	2,496,274,785.85			

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	NOV 10- DEC 10	PRELIMINARY JAN 11 - MAY 11	PRELIMINARY JUN 11 - DEC 11	DIFFERENCE CURRENT VS. JAN 11 $	DIFFERENCE CURRENT VS. JAN 11 %	DIFFERENCE JAN 11 VS. JUN 11 $	DIFFERENCE JAN 11 VS. JUN 11 %
BASE	$43.01	$43.01	$43.01	$0.00	0.00%	$0.00	0.00%
FUEL	$38.57	$42.15	$40.62	$3.58	9.28%	-$1.53	-3.63%
CONSERVATION	$1.88	$3.64	$3.64	$1.76	93.62%	$0.00	0.00%
CAPACITY PAYMENT	$6.21	$6.55	$8.22	$0.34	5.48%	$1.67	25.50%
ENVIRONMENTAL	$1.79	$1.43	$1.43	-$0.36	-20.11%	$0.00	0.00%
STORM RESTORATION SURCHARGE	$1.17	$1.17	$1.17	$0.00	0.00%	$0.00	0.00%
SUBTOTAL	$92.63	$97.95	$98.09	$5.32	5.74%	$0.14	0.14%
GROSS RECEIPTS TAX	$2.38	$2.51	$2.52	$0.13	5.46%	$0.01	0.40%
TOTAL	$95.01	$100.46	$100.61	$5.45	5.74%	$0.15	0.15%

APPENDIX V
BASED ON AGREEMENT METHOD
INCLUDING SCHERER UNIT 4 UPGRADE

APPENDIX VI
FUEL COST RECOVERY

2011 REVENUE REQUIREMENT

EXHIBITS OF KIM OUSDAHL

WCEC UNIT 3
2011 REVENUE REQUIREMENT

Line No.	WCEC3 Revenue Requirement Calculation	06/01/2011 - 12/31/2011	
1	**Jurisdictional Adjusted Rate Base**	**$845,832,095**	KO-2 Line 26 Column C
2			
3	**Rate of Return on Rate Base**	**8.422%**	KO-2 Line 3 Column D
4			
5	**Required Jurisdictional Net Operating Income**	**71,236,487**	Line 1 x Line 3
6			
7	**Partial Year Required Net Operating Income (7/12)**	**41,554,617**	Line 5 x (7/12)
8			
9	**Jurisdictional Adjusted Net Operating Income/(Loss)**	**(19,413,788)**	KO-2 Line 50
10			
11	**Net Operating Income Deficiency (Excess)**	**60,968,406**	Line 7 - Line 9
12			
13	**Net Operating Income Multiplier**	**1.63411**	
14			
15	**2011 Revenue Requirement - First 7 Months Operation**	**$99,629,081**	Line 11 x Line 13
16			
17			
18			
19	**NOTES:**		
20	1. These numbers are based on the supporting data FPL utilized in its need determination request in Docket 080203-EI.		
21	(excluding the net operating income multiplier, which is from FPL's rate case Docket 080677-EI and PSC Order 10-0153-FOF-EI).		

Revenue Requirement Backup Data

Line No	A Capital Structure		B Ratio	C Cost Rate	D Wtd Cost Rate	E Pre Tax COC
1	Long Term Debt	See Note 1	44.200%	6.430%	2.84206%	2.84206%
2	Common Equity	See Note 1	55.800%	10.000%	5.58000%	9.08425%
3	Total		100.000%		8.42206%	11.92631%
4						
5	Income Taxes					3.504%
6						
7	**Assumptions**					
8	Income Tax Rate		38.575%			
9	Production Depreciation Rate		4.000%			
10	Transmission Depreciation Rate		2.500%			
11	Rate of Return		8.42206%			
12						
13						
14	**Net Plant**		**6/01/2011**	**12/31/2011**		
15	Production Plant		819,157,500	819,157,500		
16	Transmission Plant		45,570,260	45,570,260		
17	Production Reserve		0	(19,113,675)		
18	Transmission Reserve		0	(664,566)		
19	Deferred Taxes		9,376,790	4,664,390		
20	Net Plant	See Note 1	874,104,550	849,613,909		
21						
22						
23				**6/01/2011-12/31/2011**		
24	**Average Rate Base**	(Line 20 Column B + Line 20 Column C)/2		861,859,229		
25	Juris Factor	MFR B-2 2010		0.981404		
26	**Juris Rate Base**	Line 24 x Line 25		845,832,095		
27						
28	**Juris Interest Expense**	Line 26 Column C x Line 1 Column D x (7/12)		14,022,782		
29	**Income Tax - Interest Expense**	Line 8 x Line 28		(5,409,288)		
30						
31						
32	**Operating Expenses**			**6/01/2011-12/31/2011**		
33	Other O&M	See Note 1		11,041,700		
34	Depreciation	See Note 1		19,778,241		
35	Taxes Other Than Income Taxes	See Note 1		9,079,640		
36	Total Operating Expenses	Line 33 + Line 34 + Line 35		39,899,581		
37						
38	**Juris Operating Expenses**	Line 33 x .98069 + ((Line 34 + Line 35)x Line 25)		39,149,725		
39	**Income Tax - Operating Expenses**	Line 8 x Line 38		(15,102,006)		
40						
41	**Other Income Taxes**	See Note 1		790,050		
42	**Juris Other Income Taxes**	Line 25 x Line 41		775,358		
43						
44						
45	**Juris Net Operating Income**			**6/01/2011-12/31/2011**		
46	Operating Expenses	-Line 38		(39,149,725)		
47	Income Tax - Operating Expenses	-Line 39		15,102,006		
48	Income Tax - Interest Expense	-Line 29		5,409,288		
49	Other Income Taxes	-Line 42		(775,358)		
50	**Juris Net Operating Income/(Loss)**	Line 46+Line 47+Line 48+Line 49		(19,413,788)		
51						
52	**NOTES:**					
53	1. These numbers are based on the supporting data FPL utilized in its need determination request in Docket 080203-EI					
54	(excluding cost of common equity and jurisdictional separation factor, which is from FPL's rate case Docket 080677-EI).					