BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080001-EI
FLORIDA POWER & LIGHT COMPANY

SEPTEMBER 2, 2008

IN RE: LEVELIZED FUEL COST RECOVERY AND CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2009 THROUGH DECEMBER 2009

TESTIMONY & EXHIBITS OF:

G. YUPP
T.O. JONES
K. M. DUBIN
T.W. GERRISH

AFFIDAVITS OF:

R. DEATON
S. SIM

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 080001-EI

SEPTEMBER 2, 2008

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 provide a description of the methodology that FPL will utilize to track and recover incremental O&M costs it incurs to make non-separated wholesale energy sales consistent with Commission Order No. PSC-00-1744-PAA-EI. Lastly, I provide a review of FPL's hedging program and present FPL's Risk Management Plan for 2009.

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-3: Appendix I
- GJY-4: FPL's 2009 Risk Management Plan
- Schedules E2 through E9 of Appendix II

FUEL PRICE FORECAST

Q. What forecast methodologies has FPL used for the 2009 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 transact 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 4, 2008 for its 2009 projection filing. This was the most recent date that allowed FPL adequate time to complete its filing.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2009 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 fuel supply and transportation contracts; and (10) domestic and global inventory.

The major driver for crude oil and petroleum product prices during the remainder of 2008 and 2009 will be (1) non-OPEC crude oil production; (2) emerging markets oil demand and; (3) the continued tensions in the Middle East, West Africa (in particular Nigeria) and other producing regions in the world. With limited spare OPEC production capacity and growing worldwide demand, any perceived or actual loss of supply due to political or civil unrest in these regions have been, and will continue to be, a major factor in the price of oil to FPL's customers. World demand for crude oil and petroleum products is projected to increase slightly in 2009 over 2008 average levels, primarily due to increases in demand in China and other emerging economies around the world. Although crude oil production and worldwide refining capacity will be adequate to meet the projected increase in crude oil and petroleum product demand, general adherence by OPEC members to its most recent production accord, and limited spare OPEC production capacity, should prevent significant overproduction of crude oil which, in turn, will result in the continued tight supply of crude oil and petroleum products during most of 2009.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2009 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 above for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2009 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.

Although FPL has historically burned petroleum coke at SJRPP, current and projected delivered petroleum coke prices have risen above the delivered price of coal, resulting in a projected 2009 fuel mix of 100% coal for SJRPP.

Q. Please provide FPL's projection for the dispatch cost of SJRPP and Plant Scherer for the January through December 2009 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 2009 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.

The major drivers for natural gas prices during 2009 are expected to be (1) projected natural gas demand in North America will continue to grow moderately in 2009, primarily in the electric generation sector; and (2) with continued increases in domestic rig activity in the U.S. over the past few years, 2009 domestic natural gas production is expected to be slightly higher than average 2008 production levels, as a continued decline in the Gulf of Mexico region is more than offset by increases in non-conventional gas supplies in the Rocky Mountain and Mid-Continent regions. The remaining balance of supply is projected to come from increased LNG imports.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December 2009 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 limited number of operational receipt points into the Gulfstream pipeline; (4) the portion of FGT and Gulfstream capacity that is contractually committed to FPL on a firm basis each month; (5) the assumed volume of natural gas which can move from the Gulfstream pipeline into FGT at the Hardee and Osceola interconnects; and (6) the natural gas demand in the State of Florida.

The current capacity of FGT into the State of Florida is about 2,030,000 million BTU per day and the current capacity of Gulfstream is about 1,100,000 million BTU per day. For 2009, FPL has firm natural gas transportation capacity on FGT ranging from 750,000 to 874,000 million BTU per day, depending on the month, and 535,000 million BTU per day increasing to 695,000 million BTU per day on June 1, 2009 of firm natural gas transportation on Gulfstream. Additionally, FPL will have 500,000 million BTU per day of firm transport on the Southeast Supply Header (SESH) pipeline.

The projected in-service date for the SESH pipeline is September 2008. While the SESH pipeline will not increase transportation capacity into the state, FPL's firm transportation rights on this pipeline will provide FPL access to 500,000 million BTU per day of on-shore natural gas supply, which will help diversify FPL's natural gas portfolio and enhance the reliability of fuel supply. FPL projects that during the January through December 2009 period between 100,000 and 420,000 million BTU per 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. This projection is based on the current capability and availability of the two interconnections between Gulfstream and FGT pipeline systems, as well as the availability of capacity on each pipeline.

Q. Please provide FPL's projections for the dispatch cost and availability of natural gas for the January through December 2009 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.

<u>PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY</u>

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 2009?

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 2009.

Q. Please describe the significant planned outages for the January through December 2009 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. Turkey Point Unit 3 is scheduled to be out of service from March 1, 2009 until April 5, 2009 or 35 days during the period. St. Lucie Unit 2 is scheduled to be out of service for refueling from April 27, 2009 until June 2, 2009 or 36 days during the projected period. Turkey Point Unit 4 is scheduled to be out of service from October 25, 2009 until December 4, 2009 or 40 days during the period.

Q. Please list any changes to FPL's generation capacity projected to take place during the January through December 2009 period.

A. FPL's generation capacity will increase in 2009 with the addition of the combined cycle West County Energy Center (WCEC) Unit 1 in June 2009 and the combined cycle WCEC Unit 2 in November 2009. The units will increase FPL's net winter peak capability and net summer peak capability by 1,335 MW and 1,219 MW, respectively.

Q. Will the addition of WCEC Units 1 and 2 result in fuel savings to FPL's customers?

A. Yes. The addition of WCEC Unit 1 will result in approximately $152,590,000 in fuel savings from May through December, 2009 and the addition of WCEC Unit 2 will result in approximately $12,260,000 in fuel savings from November through December, 2009. In total, the addition of these highly efficient, combined cycle units will result in approximately $164,850,000 in fuel savings to FPL's customers in 2009.

Q. How did FPL calculate the fuel savings associated with the addition of WCEC Units 1 and 2?

A. FPL utilized its POWRSYM model to quantify the benefits of WCEC Units 1 and 2. This is the same model that FPL uses to calculate the fuel costs that are included in FPL's projection filing. For this analysis, FPL ran four individual cases to determine fuel costs. The first set of cases involved two runs, one without WCEC Units 1 and 2 and one with WCEC Unit 1. The total fuel costs of the case that included WCEC Unit 1 were approximately $152,590,000 lower than the case without both units. The second set of cases also involved two runs, one with both WCEC Units 1 and 2 and one without WCEC Unit 2. The total fuel costs of the case that included both units were approximately $12,260,000 lower than the case without WCEC Unit 2.

<u>WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS</u>

Q. Are you providing the projected wholesale (off-system) power and purchased power transactions forecasted for January through December 2009?

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 the customer 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 has become a member of the Florida Cost-Based Broker System (FCBBS) and will begin transacting on the FCBBS when it becomes operational in early 2009. 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 1,491,500 MWh of wholesale (off-system) power sales for the period of January through December 2009. The projected fuel cost related to these sales is $112,997,486. The projected transaction revenue from these sales is $134,641,669. The projected gain for these sales is $18,447,799.

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 2009 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 1,196,000 MWh at a cost of $116,281,945. If FPL generated this energy, FPL estimates that it would cost $132,608,382. Therefore, these purchases are projected to result in savings of $16,326,437.

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

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

Capacity that FPL purchases through short-term agreements will be slightly lower in 2009 compared with 2008, as FPL's agreement with Constellation Energy Commodities Group, Inc. expires on April 30, 2009. The capacity associated with this contract is projected to range from 0 MW to 105 MW, depending on the availability of transmission service, during the first four months of 2009. FPL's 2009 short-term capacity contracts involving the output of specific generating units are with Southern Power Company (Oleander) for the output of one combustion turbine and with Reliant Energy Services (Indian River) for the output of three conventional steam units totaling 576 MW. The Southern Power Company (Oleander) agreement expires on May 31, 2012. The Reliant Energy Services (Indian River) contract expires on December 31, 2009.

Additionally, FPL has one short-term capacity arrangement with Bear Energy, LP that began on March 3, 2006 and runs through December 31, 2009. This transaction is for 106 MW of capacity. 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 2009 period.**

A. Under the UPS agreement, FPL's capacity entitlement during the period from January through December 2009 is 931 MW. Based upon the alternate and supplemental energy provisions of UPS, an availability factor of 100% is applied to these capacity entitlements to project energy purchases. The projected UPS energy (unit) cost for this period, used as an input to POWRSYM, is based on data provided by the Southern Companies. UPS energy purchases are projected to be 8,035,530 MWh for the period at an energy cost of $217,677,000. The total UPS energy projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of SJRPP are projected to be 2,903,503 MWh for the period at an energy cost of $97,379,000. 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 412,552 MWh at a cost of $2,521,684. These projections are shown on Schedule E7 of Appendix II.

FPL projects to dispatch 384,065 MWh from its short-term capacity agreements at a cost of $33,752,059. 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 5,572,282 MWh at a cost of $235,952,993.

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 537,402 MWh of energy at a cost of $3,092,615. 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.

OPERATION AND MAINTENANCE (O&M) EXPENSES ASSOCIATED WITH NON-SEPARATED WHOLESALE ENERGY SALES

Q. Does FPL currently recover incremental O&M costs associated with generating energy for non-separated wholesale sales?

A. FPL currently recovers incremental O&M costs for off-system sales that are supported by FPL's gas turbine facilities. These gas turbine facilities are comprised of 24 peaking units at FPL's Fort Lauderdale facility, 12 peaking units at FPL's Port Everglades facility and 12 peaking units at FPL's Fort Myers facility.

Q. What methodology does FPL utilize to recover the incremental O&M costs associated with off-system sales that are supported by FPL's gas turbine facilities?

A. FPL currently estimates the incremental O&M costs associated with its gas turbine facilities on a dollars per MWh basis. The units at Fort Lauderdale and Port Everglades are identical and therefore the estimated incremental O&M costs for each facility are the same. The estimated incremental O&M cost for the Fort Myers peaking units is calculated separately, as these units are not similar to Fort Lauderdale and Port Everglades.

Off-system sales supported by gas turbines are tracked in MWh and recorded on a daily basis. At the end of each month, the MWh contributions from each facility are multiplied by the appropriate estimated incremental O&M cost to produce the total incremental O&M costs associated with off-system sales that were supported by FPL's gas turbines. The total incremental O&M costs are then subtracted from the total fuel costs (Column 7) on Schedule A6 and recorded as a credit to base operating revenues. This final credit for the fuel cost of power sold is also shown on Line 2a of Schedule A2 and the combination of Lines 14 and 16 on Schedule A1.

Q. Is FPL proposing to change its methodology for recovering incremental O&M costs associated with off-system sales?

A. No, but FPL is proposing to extend its current methodology to include other types of units in FPL's fleet. Specifically, FPL proposes to add two additional categories of units that contribute substantially to off-system sales: combined cycle units and conventional steam units. As with the gas turbine facilities, FPL will estimate the incremental O&M costs for each class of units, track the MWh of sales attributable to each class of units and calculate the total incremental O&M costs associated with off-system sales.

Q. Does the Commission currently allow for the recovery of incremental O&M costs associated with off-system sales for units other than gas turbines?

A. Yes. Order No. PSC-00-1744-PAA-EI addressed the issue of incremental O&M related to off-system sales by stating the following:

> "Because the IOUs sell short-term wholesale energy based upon their willingness and ability to sell at or above incremental costs, we believe that the IOUs should measure the costs of these sales on an incremental basis. Accordingly, we find that each IOU shall measure the gain from its non-separated wholesale power sales by subtracting the sum of its incremental costs from the revenue received

> for each sale. Further, we find that the calculation of incremental costs for these sales shall include, but not be limited to: incremental fuel cost, incremental SO2 emission allowance cost, incremental O&M cost, and separately-identified transmission or capacity charges."

The Order goes on to clarify the appropriate regulatory treatment for the revenues and expenses associated with non-separated wholesale power sales and specifically addresses incremental O&M recovery by stating the following:

> "Each IOU shall credit its operating revenues for an amount equal to the incremental operating and maintenance (O&M) cost of generating the energy for each such sale."

Therefore, the recovery of incremental O&M is not limited to specific types of units, but rather applies to the cost for all units generating the energy for each sale.

Q. Is FPL's current methodology for recovery of incremental O&M costs associated with off-system sales consistent with Order No. PSC-00-1744-PAA-EI?

A. Yes. Order No. PSC-00-1744-PAA-EI did not dictate specifically how each IOU should calculate the incremental O&M it incurred to make off-system sales. Similar to PEF and TECO (as described in testimony at an evidentiary hearing held in Docket No. 010283-EI on August 31, 2001), FPL estimates its incremental O&M costs and credits its operating revenues for these costs.

Q. Is FPL presently recovering incremental O&M costs for its combined cycle and conventional steam units through base rates?

A. No. The level of O&M expenses required to support the operation of power plants is almost exclusively a function of their output. FPL has confirmed that the O&M projections for its combined cycle and conventional steam units that are reflected in the most recent (2006) Minimum Filing Requirements (MFRs) did not take into account the additional operating hours and output associated with off-system sales. Rather, the O&M data was based on only the requirements of serving native load customers. Therefore, FPL is not currently recovering through base rates the incremental O&M expenses that it incurs when it runs its combined cycle and conventional steam units for more hours or at higher output levels to support off-system sales.

Q. Why has FPL not previously recovered the incremental O&M expenses associated with off-system sales from its combined cycle and conventional steam units?

A. The Commission's approved procedure for handling the revenues and costs associated with non-separated sales provides for recovery of incremental O&M expenses only when those expenses are not already recovered in base rates. When that system was established in 2000, FPL initially concluded that the level of O&M

expenses reflected in its previous MFRs for combined cycle and *conventional steam units covered the added operation of those units* when FPL makes off-system sales and therefore were not eligible for recovery via a credit to base revenues. However, when FPL recently re-evaluated the basis for projecting O&M expenses for combined cycle and conventional steam units in its most recent (2006) MFRs, it became apparent that the MFRs in fact did not cover the cost of making off-system sales from those units.

Q. **When does FPL propose to begin recovering incremental O&M costs associated with off-system sales for these additional units?**

A. FPL proposes to begin recovering incremental O&M costs associated with off-system sales for combined cycle and conventional steam units starting on January 1, 2009. This projected date will allow FPL the necessary time to modify its systems to appropriately capture and account for these incremental costs.

Q. **Do FPL's 2009 fuel cost projections reflect FPL's recovery of incremental O&M costs for combined cycle and conventional steam units?**

A. No. FPL does not feel that it has enough information on the unit types from which off-system sales will be made in 2009 to project accurately the incremental O&M costs associated with those sales.

As FPL has done historically for its gas turbine units, recovery of the incremental O&M costs for combined cycle and conventional steam units will be handled as part of the final true-up for 2009 and subsequent years.

Q. How will FPL reflect these costs on Schedule A6?

A. FPL plans to show these costs on Schedule A6 as it currently does for gas turbine-related O&M costs. FPL will change the line item description on Schedule A6 from "Gas Turbine Maintenance Revenue Reclassed to Base Revenue" to "System Maintenance Revenue Reclassed to Base Revenue."

Q. Does FPL plan to update its estimated values for incremental O&M by unit class on a routine basis?

A. Yes. FPL will update its cost estimates, by unit class, on a yearly basis.

__HEDGING/ RISK MANAGEMENT PLAN__

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. Does FPL expect that its hedging program will deliver fuel savings each year?

A. No. This is a point that I have emphasized in all my prior testimony on hedging. While FPL is extremely pleased when its hedging program generates net savings for its customers, it does not engage in hedging for this purpose. FPL's hedging strategies are aimed at reducing fuel price volatility. Speculative hedging strategies aimed at "out guessing" the market in the hopes of potentially returning savings to FPL's customers will lead to increased volatility in prices to FPL's customers. FPL cannot predict future fuel prices as there is no certainty in predicting the main drivers of fuel price, such as weather, hurricanes or unstable conditions around the world. What FPL can continue to do is execute a well-disciplined, independently controlled hedging program that reduces fuel price volatility and delivers greater price certainty to FPL's customers. As a consequence of volatility reduction, the hedging program will show savings in some years and losses in others, with the expectation that, over time, the cumulative impact of FPL's hedging program will be neutral and not result in significant savings or losses to FPL's customers. FPL does expect, however, that over time its customers will experience more stable rates as a result of FPL's hedging activities.

Q. Has FPL prepared a risk management plan for 2009, as required by Order PSC- 02-1484-FOF-EI issued on October 30, 2002?

A. Yes. FPL's 2009 Risk Management Plan is provided in Exhibit GJY-4. FPL's 2009 Risk Management Plan has been modified from prior years to include a greater level of detail in response to recommendations in Staff's recent *Review of Fuel Procurement Hedging Practices of Florida's Investor-Owned Electric Utilities*. In addition, FPL's 2009 Risk Management Plan addresses the parameters within which FPL intends to place hedges in 2009 for fuel requirements in 2010.

Q. Is FPL seeking to recover projected incremental operating and maintenance expenses with respect to maintaining an expanded, non-speculative financial and/or physical hedging program for the January through December 2009 period?

A. Yes. FPL projects to incur incremental expenses of $694,510. By "incremental," I mean that these expenses are not reflected in FPL's base rates. The projected expenses are comprised of salaries and employee-related expenses for the three personnel who were added to support FPL's enhanced hedging program, incremental annual license fees for FPL's volume forecasting software and incremental expenses associated with credit costs necessary to support FPL's hedging program.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY O. JONES

DOCKET NO. 080001-EI

September 2, 2008

Q. Please state your name and address.

A. My name is Terry O. Jones. 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). My current position is the Vice President of Operations Midwest Region for the Nuclear Division. Prior to this change, which became effective June 2008, I served as Vice President of Plant Support for FPL's Nuclear Division.

Q. Have you previously testified in the predecessor to this docket?

A. Yes, I have.

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 2009 through December 2009.

<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 2009 through December 2009.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2009 through December 2009.

A. FPL projects the nuclear units will produce 261,998,614 MMBTU of energy at a cost of $0.5308 per MMBTU, excluding spent fuel disposal costs, for the period January 2009 through December 2009. Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 15 of the Appendix II.

Spent Nuclear Fuel Disposal Costs

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2009 through December 2009 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $21.8 million are provided in Appendix II, on Schedule E-2, starting on page 9 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 0.9285 mills per net kWh generated, including transmission and distribution line losses.

Litigation Status Update

Q. Is there currently an unresolved dispute under FPL's nuclear fuel contracts?

A. Yes.

Spent Fuel Disposal Dispute. This dispute arose under FPL's contract with the Department of Energy (DOE) for final disposal of spent nuclear fuel. In 1995 FPL, along with a number of electric utilities, states, and state regulatory agencies filed suit against DOE over its obligation to accept spent nuclear fuel beginning in 1998. On July 23, 1996, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) held that DOE is required by the

Nuclear Waste Policy Act (NWPA) to take title to and dispose of spent nuclear fuel from nuclear power plants beginning on January 31, 1998.

On January 11, 2002, based on the D.C. Circuit's ruling, the Court of Federal Claims granted FPL's motion for partial summary judgment in favor of FPL on contract liability. There is no trial date scheduled at this time for the FPL damages claim.

The Court of Federal Claims ruled on May 21, 2004 that another nuclear plant owner, Indiana Michigan Power Company, was not entitled to any damages arising out of the Government's failure to begin disposal of spent nuclear fuel by January 31, 1998. On appeal, the U.S. Court of Appeals for the Federal Circuit upheld the Court of Federal Claims decision on September 9, 2005. The impact of this decision, if any, on FPL's claims against the Government remains unknown at this time.

Nuclear Plant Security Costs

Q. What is FPL's projection of the incremental security costs for the period January 2009 through December 2009?

A. FPL presently projects that it will incur $30.3 million in incremental nuclear power plant security costs in 2009.

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

A. The projection includes adding security personnel as a result of implementing NRC's Order EA03-038, which limits the number of hours security personnel may work; additional personnel training; additional regulatory initiatives for fires, aircraft threat strategy; protection of spent fuel pools and containments and impacts of NRC Part 73 rulemaking initiatives.

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

A. Yes. On March 31, 2008 the NRC issued a new rule under Part 26 of the Code of Federal Regulations dealing with worker fatigue. The new rule mandates more restrictive work hour limits, including a specific requirement for "days off" for the security officers at the St. Lucie and Turkey Point sites. Full implementation is required by October 1, 2009. The Part 26 rulemaking impacts costs for 2009 are estimated to be $1.8 million for the St. Lucie and Turkey Point nuclear sites.

Q. Is there a possibility of further NRC security-related initiatives in 2009 and beyond, in addition to those included in FPL's projection?

A. Yes. For example, there is a NRC initiative to review and update the Enhanced Adversary Characteristics (EAC) of the Design Basis Threat (DBT). The DBT is the measure that all nuclear stations are designed to defend against. Some of these EAC/DBT enhancements could require extensive engineering support and significant modifications to station security defensive positions. Industry comments are due to the NRC by September 2008.

In addition, NRC Part 73.55 rulemaking may involve the need for significant modifications to various areas of the site. Part 73.55 directs licensees to have an on-site physical protection system and security organization that provides the level of protection required for nuclear power reactors against radiological sabotage. Some examples include redundant features for Central Alarm Station (CAS) and Secondary Alarm Station (SAS), enhanced weaponry, Owner Controlled Area (OCA) detection, and possible enhancements to assessment and interdiction. The industry and the NRC view the impact differently since the industry believes a literal interpretation of the proposed rule varies greatly from the NRC's stated intent. Nuclear Energy Institute (NEI) has 200 pages of comments discussing the impact of this rule. NEI estimates that the cost of rulemaking, based on literal interpretation, could range from $20-60 million per site.

As a final example, the NRC has issued a draft Regulatory Guide for Cyber Security protection of station digital computer, communications systems and networks which would impose significant requirements for monitoring, hardening and responding to cyber intrusions. The draft Guide has been issued for industry comment.

It is not feasible for FPL to estimate at this time the future costs that will be required to comply with the various developing regulatory requirements, but the Commission should be aware that nuclear security costs could increase significantly based on the issues mentioned above.

2008 Outage Events

Turkey Point

Q. Has FPL experienced any unplanned outages at its Turkey Point plant in 2008?

A. Yes. In February 2008, Units 3 and 4 experienced an automatic reactor trip and shut down due to an external transmission disturbance that caused reduced voltage in the switchyard that connects the nuclear units to the FPL transmission system. Additionally, when Unit 4 was returning to service, the 4A steam generator water level exceeded the 75% limit and a manual trip was initiated. The manual trip delayed start up by approximately 30 hours. The total outage duration for these events, including the equipment issues that emerged independently of the transmission incident, was approximately 6 days for Unit 3 and 4 days for Unit 4.

Q. What caused the 4A steam generator water level to exceed 75%?

A. In an effort to accelerate the return of Unit 4 to service, the operator implemented fast generator loading that created steam generator level fluctuations and the loss of steam generator level control which resulted in the manual trip of the reactor.

Q. Why was the outage duration for Unit 3 longer than Unit 4?

A. Unit 3 extended the outage to replace a rod position indication coil that had previously malfunctioned in October 2007. FPL had obtained permission from the NRC to defer replacement until a unit shut down occurred in order to minimize the outage time associated with the replacement.

Q. Has FPL experienced any other unplanned outages at its Turkey Point plant in 2008?

A. Yes. In June 2008, Unit 3 shut down to rebalance the turbine, due to a high #9 turbine bearing vibration. The outage duration was approximately 1 day. In August 2008, Turkey Point Unit 4 shut down to repair a test connection leak required by technical specifications and American Society of Mechanical Engineers (ASME) code requirements. The outage duration was approximately 8 days.

St. Lucie

Q. Has FPL experienced any unplanned outages at its St. Lucie plant in 2008?

A. Yes. In January 2008, St. Lucie Unit 2 was manually shut down due to a leak in the 2B1 Reactor Coolant Pump (RCP) seal upper cavity piping. The leakage occurred on a Reactor Coolant Pump seal upper cavity pipe. FPL determined the crack was due to water chemistry and the piping design. The January 2008 outage duration was approximately 11 days.

Q. What corrective actions has FPL taken to avoid this problem from recurring?

A. FPL replaced the 12 seal upper cavity lines in the "A" and "B" reactor coolant pumps to preclude a similar problem on these lines in the future on Unit 2.

Q. Has this issue occurred in St. Lucie Unit 1?

A. No. However, as a precautionary measure, FPL will be replacing all 16 seal cavity lower and upper lines during the refueling outage in October 2008 to avoid future problems on Unit 1.

Q. Has FPL experienced any other unplanned outages at its St. Lucie plant in 2008?

A. In June 2008 St Lucie Unit 2 was manually shut down due to a secondary side transient. This transient occurred during maintenance activities to replace a feedwater heater level detector. The outage duration for this event was approximately 2 days.

Also in June 2008, St Lucie Unit 2 was manually shut down due to a trip of a main condensate pump when the motor leads associated with this pump electrically faulted. The outage duration for this event was approximately 2 days.

In August 2008, St. Lucie Unit 1 shut down due to flooding associated with the unprecedented amount of rainfall from Tropical Storm Fay. The outage duration was approximately 5 days.

FPL is in the process of investigating and evaluating these recent outages.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 080001-EI

September 2, 2008

Q. Please state your name and address.

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

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

A. I am employed by Florida Power & Light Company (FPL) as Senior Manager of Purchased Power in the Resource Assessment and Planning 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 for Commission review and approval the Fuel Cost Recovery (FCR) factors for the period January 2009 through December 2009. I propose that the FCR factors be adjusted during the period in order to offset the impact of the Generation Base Rate Adjustments (GBRAs) for West County Energy Center (WCEC) Units 1 and 2 and thus levelize the 1,000 kWh residential customer bill throughout the period. I also present as an alternative FCR factors that are uniform throughout the period, which would not result in levelizing the overall bill.

- I present for Commission review and approval a revised 2008 FCR estimated/actual true-up amount, which has been updated to include July actual data and which is incorporated into the calculation of the 2009 FCR Factors.
- I present for Commission review and approval the Capacity Cost Recovery (CCR) factors for the period January 2009 through December 2009.
- I present for Commission review and approval a revised 2008 CCR estimated/actual true-up amount, which has been updated to include July actual data and which is incorporated into the calculation of the 2009 CCR Factors.
- I present for Commission review and approval FPL's projected incremental security costs for 2009, to be recovered through the CCR Clause.
- Finally, I provide on pages 73-74 of Appendix II FPL's proposed COG tariff sheets, which reflect 2009 projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten year projection of Florida Power & Light Company's annual

generation mix and fuel prices.

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:

- KMD-5 -- Schedules E1, E1-A, E1-B, E1-C, E1-D E1-E, E2, E10, H1, and pages 8a-8c and 73-74 included in Appendix II
- KMD-6 -- the entire Appendix III

Appendix II contains the FCR related schedules, Appendix III contains the CCR related schedules, and Appendix IV provides the alternate FCR schedules prepared using the standard methodology.

FUEL COST RECOVERY CLAUSE

Adjusted FCR Factors to Levelize the Overall Bill

Q. Is FPL proposing to levelize the Residential 1,000 kWh bill in 2009?

A. Yes. In order to provide customers with a more stable, level bill in 2009, FPL proposes to levelize the Residential 1,000 kWh bill by offsetting the GBRAs for WCEC Units 1 and 2 with the fuel savings attributable to these new units. FPL has filed affidavits of Dr. Steven Sim and Ms. Renae Deaton documenting and describing the calculation of those GBRAs. The fuel savings of

$164,850,000 attributable to WCEC Units 1 and 2 are presented in the testimony of FPL witness G. Yupp.

Without levelization, the overall 1,000 kWh residential bill would increase in June 2009 from the level in effect for January to May 2009, when WCEC Unit 1 begins commercial operations and the WCEC 1 GBRA becomes effective. Then, the overall 1,000 kWh residential bill would increase again in November 2009, when WCEC Unit 2 begins commercial operations and the WCEC 2 GBRA becomes effective. FPL's proposal will eliminate these two step increases.

Q. **How does FPL propose to calculate the FCR factors that will implement this levelized 1,000 kWh residential bill?**

A. FPL proposes to offset the GBRAs that become effective in June 2009 (WCEC 1) and November 2009 (WCEC 2), by crediting an equivalent amount of the units' fuel savings to customers over the same timeframe that the GBRAs will be in effect for 2009. This is in contrast to the standard methodology for calculating FCR factors, in which fuel costs for a given year (including any fuel savings) are levelized over the twelve month period. Offsetting the GBRA impacts will not require all of the projected fuel savings associated with operation of WCEC Units 1 and 2 in 2009; the remaining savings will be spread over the five month period of

January through May 2009.

Specifically, as shown in Mr. Yupp's testimony, FPL projects total fuel savings of $164,850,000 in 2009, with the jurisdictional savings being $164,637,858. $93,085,358 of those savings are credited to June through October 2009 to offset the impact of the WCEC Unit 1 GBRA, and $52,955,000 of the savings are credited in November through December 2009 to offset the combined impacts of the WCEC Units 1 and 2 GBRAs in that period. The remaining fuel savings of $18,597,500 are credited in January through May 2009.

By spreading the fuel savings from WCEC Units 1 and 2 in this fashion, FPL has calculated levelized fuel factors for January through May 2009 of 6.744¢ per kWh, for June through October 2009 of 6.603¢ per kWh, and for November through December 2009 of 6.475¢ per kWh. The calculation of these FCR factors is further detailed on Schedule E1, pages 3a – 3c of Appendix II. Applying these factors results in a consistent 1,000 kWh residential bill of $119.41 over the entire January through December 2009 period.

Q. Will all rate classes see a levelized bill for the January through December 2009 period?

A. Only the "Typical" 1,000 kWh Residential Bill will be completely levelized, while for other residential consumption levels and other rate classes there will remain small differences between their bills for January through May, June through October and November through December. However, all customer classes and consumption levels will see less of a fluctuation in their bills throughout the year than they would without FPL's proposed levelization.

Q. Is FPL's levelization proposal revenue neutral?

A. Yes. The FCR Factors that FPL proposes for levelizing the bill are designed to recover the same total FCR revenues over 2009 as would standard, non-levelized FCR Factors.

Q. Has the Commission previously approved using the "levelized bill" methodology when a GBRA became effective?

A. Yes. In Order No. PSC-06-1057-FOF-EI, dated December 22, 2006, the Commission approved FPL's use of the "levelized bill" methodology for setting the 2007 FCR factors, to offset the impact of the GBRA that became effective when Turkey Point Unit 5 went into commercial operation.

<u>Alternative, "Standard" FCR Factors</u>

Q. As an alternative, is FPL also providing fuel factors using the standard methodology?

A. Yes. Although FPL requests approval of its "Levelized Bill

Methodology," in the alternative FPL has also provided fuel factors using the standard methodology. Appendix IV includes Schedules E1, E1-D, E1-E, E2, and E10, which calculate the twelve-month levelized fuel factor (standard methodology). This twelve-month levelized fuel factor spreads the savings resulting from WCEC Units 1 and 2 throughout the twelve months of 2009.

Q. What is the proposed "standard methodology" levelized fuel cost recovery (FCR) factor?

A. 6.636¢ per kWh. Schedule EI, Page 3 of Appendix IV shows the calculation of this twelve-month levelized FCR factor. Schedule E2, Pages 6 and 7 of Appendix II shows the monthly fuel factors for January 2009 through December 2009 and also the twelve-month levelized FCR factor for the period.

<u>FCR Factors for Time of Use Rates</u>

Q. Has the Company developed levelized FCR factors for its Time of Use rates, under both its "levelized bill" and standard methodologies?

A. Yes. Schedule E1-D, Pages 6a through 6c of Appendix II, provides our Time of Use rate schedules. The on-peak and off-peak FCR factors are 7.546¢ and 6.383¢ for January through May, 7.405¢ and 6.242¢ for June through October, and 7.277¢ and 6.114¢ for November through December. Schedule E-1D, Page 4 of Appendix IV provides the Time of Use rates based on the standard methodology.

The time of use rates for the Seasonal Demand Time of Use Rider (SDTR) are 7.394¢ (on-peak) and 6.354¢ (off-peak) and are provided on Schedule E-1D, Page 6d 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.

Utilizing the levelized bill approach, FCR factors by rate group for the periods January through May, June through October and November through December 2009, respectively, are presented on Schedule E1-E, Pages 7a through 7c of Appendix II. FCR factors by rate group for the SDTR are provided on Schedule E-1E, Page 7d of Appendix II.

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

A. Yes.

Q. Has FPL calculated the residential fuel charges using the inverted rate structure for both its "levelized bill" and standard methodologies?

A. Yes.

<u>**Revised 2008 FCR Estimated/Actual True-up**</u>

Q. Has FPL revised its 2008 FCR Estimated/Actual True-up amount that was filed on August 4, 2008 to reflect July actual data?

A. Yes. The 2008 FCR Estimated/actual True-up amount has been revised to an under-recovery of $296,048,402 reflecting July 2008 actual data. The calculation of the revised 2008 FCR Estimated/actual true-up amount is shown on Revised Schedule E1-B, on Pages 4a-4b of Appendix II. This $296,048,402 under-recovery is to be included for recovery in the FCR factor for the January 2009 through December 2009 period.

Q. What adjustments are included in the calculation of the levelized FCR factor shown on Schedule E1, Pages 3a – 3c of Appendix II?

A. As shown on line 29 of each Schedule E1, Pages 3a-3c of Appendix II, the total net true-up to be included in the 2009 factors is a revised under-recovery of $296,048,402. This amount divided by the projected retail sales of 105,989,914 MWh for January 2009 through December 2009 results in an increase of .2793¢ per kWh before applicable revenue taxes. The Generating Performance Incentive Factor (GPIF) Testimony of FPL Witness Frank Irizarry, filed on April 3, 2008, calculated a reward of $5,383,572 for the period ending December 2007, which is being applied to the January 2009 through December 2009 period. This $5,383,572 reward divided by the projected retail sales of 105,989,914 MWh during the projected period results in an increase of .0051¢ per kWh, as shown on line 33 of Schedule E1, Pages 3a – 3c of Appendix II.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2008 CCR Estimated/Actual True-up amount that was filed on August 4, 2008 to reflect July actual data?

A. Yes. The 2008 CCR Estimated/actual True-up amount has been revised to an under-recovery of $26,832,716 reflecting July 2008 actual data plus interest. The calculation of the revised 2008 CCR Estimated/actual true-up amount is shown on Pages 3a-3b of Appendix III.

Q. What is the revised net true-up amount that FPL is requesting to include in the CCR factor for the January 2009 through December 2009 period?

A. FPL is requesting approval of a net true-up under-recovery of $30,540,170. This $30,540,170 under-recovery represents the revised estimated/actual under-recovery for the period January 2008 through December 2008 of $26,832,716 plus the final true-up under-recovery of $3,707,455 that was filed on March 3, 2008 for the period January 2007 through December 2007. This $30,540,170 under-recovery is to be included for recovery in the CCR factor for the January 2009 through December 2009 period.

Q. Have you prepared a summary of the requested capacity payments for the projected period of January 2009 through December 2009?

A. Yes. Page 3 of Appendix III provides this summary. Total Recoverable Capacity Payments are $836,786,814 (line 18) and include payments of $223,732,036 to non-cogenerators (line1), Short-term Capacity Payments of $47,319,630 (line 2), payments of $320,771,227 to cogenerators (line 3), $2,405,832 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 4), $31,439,262 in Incremental Power Plant Security Costs (line 6), and $4,354,655 for Transmission of Electricity by Others (line 7). These amounts are offset by $5,689,352 of

Return Requirements on SJRPP Suspension Payments (line 5), by Transmission Revenues from Capacity Sales of $3,196,384 (line 8), by $56,945,592 of jurisdictional capacity related payments included in base rates (line 12) and a refund of $9,296,089 related to the true-up of the Turkey Point Unit 5 Generating Base Rate Adjustment (GBRA) for the period May 2007 through December 2008 (line 15). The resulting amount is then increased by the net under-recovery for 2008 of $30,540,170 (line 13) plus the Nuclear Cost Recovery amount of $258,406,183 (line 14).

Q. Has FPL included costs associated with its Nuclear Power Plant Cost Recovery (NPPCR) in the calculation of its Capacity Cost Recovery (CCR) Factors?

A. Yes. FPL has included $258,406,183 on Appendix III, page 3, Line 14 for the NPPCR in the calculation of its CCR Factors. Per Order No. PSC-07-0240-FOF-EI, issued on March 20, 2007, the Commission adopted the Rule to implement Section 366.93, Florida Statutes, which was enacted by the Florida Legislature in 2006. The stated purpose of the Statute is to promote utility investment in nuclear power plants, and it directed the Commission to establish alternative mechanisms for cost recovery and step-wise, periodic prudence determinations with respect to costs incurred to build nuclear power plants. The Rule provides the mechanism and the annual recovery of these costs through the CCR.

On May 1, 2008, in Docket No. 080009-EI, FPL filed a petition for cost recovery of its NPPCR amount of $258,979,772, which was subsequently revised on August 6, 2008 to $258,406,183.

This $258,406,183 is made up of 2006-2007 actual costs, 2008 estimated/actual costs and 2009 projected costs. It includes $7,766,748 of site selection costs, $230,414,344 of pre-construction costs and associated carrying charges for Turkey Point Units 6 &7 and $20,225,091 of carrying charges on construction costs associated with the St. Lucie and Turkey Point Nuclear Uprate Projects.

Q. Has FPL included an adjustment associated with its Generating Base Rate Adjustment (GBRA) for Turkey Point Unit 5?

A. Yes. FPL has included a credit of $9,296,089, including interest, (Appendix III, page 3, Line 15) for the true-up of Turkey Point Unit 5 costs for the period May 1, 2007 through December 31, 2008 as a reduction in the calculation of its CCR Factors. The calculation of this credit is discussed in the affidavit and exhibits of Renae B. Deaton.

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

A. Yes. Page 4 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 contributes to total kWh sales, as adjusted for losses, for each rate class.

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

A. Yes. Page 5 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 2009 through December 2009. This will provide for 12 months of billing on the FCR and CCR factors for all our customers.

Q. **What will be the charge for a Residential customer using 1,000 kWh effective January 2009?**

A. For January through December, the "typical" Residential 1,000 kWh bill will be $119.41 Of this amount, the Capacity Cost Recovery charge is $8.55, the Conservation charge is $2.04, the Environmental Cost Recovery charge is $0.94, the Storm charge is $1.45 and the Gross Receipts Tax is $2.99.

In addition, the January through May period includes a base charge of $39.31 and the fuel cost recovery charge is $64.13. For June through October, the bill includes a base charge of $40.72 and the fuel cost recovery charge is $62.72. For November through December, the bill includes a base charge of $42.00 and the fuel cost recovery charge is $61.44.

A comparison of the current Residential (1,000 kWh) Bill to FPL's 2009 projected Residential (1,000 kWh) Bills is presented in Schedule E10, Page 71 of Appendix II. As shown on Schedule E10, the 1,000 kWh Residential Bill will increase by 7.80% in January 2009.

Q. How do these increases compare to the increases sought and received by other utilities around the country?

A. They are consistent with, and in some instances significantly lower than, fuel-related increases seen elsewhere recently. For example, in June 2008 Dominion Virginia Power received an 18% increase in its residential rates to cover higher fuel costs. Similarly, in July 2008, Appalachian Power Company sought an increase in its fuel factors that would raise residential rates by about 15%, and in August 2008, Alabama Power Company sought a 14.6% increase in residential rates due to rising costs for coal and natural gas. All of these increases reflect the same reality of sharply increasing fuel costs that FPL faces. I also would like to point out that a significant portion of the increase in FPL's bills reflects investment in clean power technologies such as nuclear, solar and highly efficient combined cycle gas-fired plants, which will help FPL to reduce its reliance on fossil fuels and cut its greenhouse gas and other air emissions in the years to come.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TIMOTHY GERRISH

DOCKET NO. 080001-EI

September 2, 2008

Q. Please state your name and business address.

A. My name is Timothy Gerrish. My business address is 700 Universe Blvd., Juno Beach, FL 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 the Director of Origination.

Q. What are your present job responsibilities?

A. My current responsibilities include: managing the long term marketing and purchasing of energy commodities to support FPL's System of Generation. Through this function, I assess and negotiate opportunities to enter into procurement or sales of power, natural gas and coal contracts.

Q. Would you please give a brief description of your educational background and professional experience?

A. I received a Bachelor of Science Degree in Electrical Engineering from Michigan Technological University in 1989, and a Masters of Business Administration Degree in 2001 from the University of North Carolina – Chapel Hill. I have been employed in my current position at FPL since August 24, 2007. From 1998 until 2007, I was employed by Progress Energy's unregulated affiliate, Progress Ventures, LLC. In 2007, Progress Ventures sold a portion of its business to Constellation Energy, where I briefly worked prior to joining FPL. Throughout my employment at Progress Ventures I held a number of positions in Energy Marketing and Trading, where I had responsibility for various regulated and unregulated power projects, including responsibility for negotiation and administering power purchase agreements. Prior to joining Progress Ventures, I was a United States Naval Submarine Officer for nine years.

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

A. My testimony is provided in support of FPL's request for a Commission finding that entering into the Lee County Electric Cooperative, Inc. ("LCEC") Long-Term Agreement for Full Requirement Electric Service dated August 21, 2007 ("Agreement") is prudent and consistent with the interests of FPL's retail customers. The load obligation represented by the Agreement is expected to average approximately 1,100 MW over the term of the Agreement. My testimony describes the Agreement, identifies its principal benefits, and explains why the Commission should find that entering into the Agreement is prudent and consistent with the interests of FPL's retail customers.

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

A. Yes. The following exhibits are included in Appendix V:

Exhibit TWG - 1 -- Long-Term Agreement for Full Requirements Electric Service

Exhibit TWG – 2 –Retail Impact Analysis (July 2007)

Q. Please describe the contract and summarize its key elements.

A. FPL negotiated the Agreement (my Exhibit TWG – 1) to sell Full Requirements Electric Service to LCEC. Under the Agreement, FPL would supply all of LCEC's electrical energy needs from January 1, 2014 until December 31, 2033. LCEC would pay FPL a monthly capacity and energy payment, both of which are derived through cost-of-service formulas that are tied to actual FPL System Capital and Operating costs. The Agreement has provisions that allow the term to extend an additional 20 years (to 2053) unless one of the parties terminates the agreement prior to December 31, 2026.

Q. What is FPL's purpose in entering into the Agreement?

A. FPL was contacted by LCEC and advised that they were interested in pursuing alternative power supply solutions to meet the needs of their customers. The Agreement will allow LCEC and its customers to benefit from FPL's reliable and cost effective electrical service, in a manner that is not detrimental to FPL's retail customers.

Q. How does LCEC currently meet its load obligations?

A. LCEC is a member-owner of Seminole Electric Cooperative, Inc. ("Seminole"). Currently, LCEC receives 100% of their capacity and energy through power supply arrangements with Seminole. LCEC has provided notice to Seminole terminating their power supply arrangement. Beginning in 2010, FPL will supply up to 300 MW of Partial Requirements service to LCEC under a separate Short Term Agreement to meet a portion of LCEC's capacity and energy needs prior to the commencement of this Agreement.

Q. Please provide an overview of the Agreement.

A. Under the Agreement, FPL would serve the capacity and energy needs of LCEC just as it would serve FPL's retail load. FPL would forecast LCEC's load requirements and incorporate LCEC's load in its total load serving obligations. FPL would plan future generation additions around meeting this total load obligation. FPL would deliver the capacity and energy to LCEC's load through FPL's transmission system pursuant to FPL's Open Access Transmission Tariff. LCEC has requested and subsequently been granted firm Network Transmission Service for the term of the Agreement. LCEC is responsible for paying the Network Transmission Service Tariff Rate and is in the process of entering into Transmission Service Agreements with FPL Transmission.

On a monthly basis, LCEC would pay FPL for the capacity and energy that is required to meet LCEC's load. FPL has designed a cost-based formula rate that captures FPL system costs associated with providing the capacity and energy consistent with Federal Energy Regulatory Commission ("FERC") guidelines. These costs include but are not limited to capital, capital recovery, O&M, property taxes, emissions, corporate overhead, purchased power and fuel (nuclear, gas, coal and oil).

Q. Does the Agreement contain any terms relating to Commission approval?

A. Yes. The Agreement makes Commission approval of the Agreement a condition precedent. If the Commission does not grant approval satisfactory to FPL by December 31, 2009, then

FPL will have the right to terminate the Agreement. There is also a condition precedent relating to FERC approval of the Agreement, which also gives FPL the right to terminate the Agreement if FERC does not grant satisfactory approval by December 31, 2009.

Q. Why is FPL seeking Commission approval for the Agreement?

A. The Agreement represents a large, long-term, discretionary commitment of FPL's resources to serving load outside its own retail service territory. LCEC and FPL have concluded that the Agreement will be in the interests of both utilities and their customers, and is consistent with Florida's interest in diversifying the access to and utilization of generating resources within the state. Because of the size and duration of the commitment, however, FPL feels that it is important to confirm that the Commission concurs with our conclusions.

Q. Is the LCEC load associated with the Agreement included in FPL's current Ten Year Site Plan?

A. Yes. The Agreement was executed on August 21, 2007 and thus FPL's 2008 Ten Year Site Plan contemplates serving the LCEC load. Entering into the Agreement would be consistent with that plan.

Q. What are the key benefits of entering into this Agreement?

A. This Agreement offers several important benefits to both FPL and LCEC. In conjunction with the Agreement:

1) FPL will be able to leverage its economies of scale. The LCEC load will represent approximately 1,100 MW of additional capacity and energy to which FPL can allocate certain fixed costs (i.e. overhead) through the cost-of-service rate structure.

2) LCEC will receive reliable and cost effective electrical service from the largest utility in the State with a substantial number of generating resources and significant fuel diversity.

3) In view of the benefits both to LCEC customers and FPL customers, this Agreement will enhance the use of Florida's generating resources. FPL has demonstrated over time that we are an efficient, cost effective and environmentally friendly builder of new generation in Florida. The future generation that FPL builds to meet load growth, including LCEC load, will leverage those core competencies to serve the greater needs of all Floridians and not just retail customers of FPL.

Q. What has FPL done to evaluate the impact of the Agreement on its retail customers?

A. FPL conducted an extensive analysis to determine the impact to FPL's retail customers as a result of serving LCEC load under this Agreement. FPL analyzed two separate scenarios to support this analysis. The first scenario, or "Base Case," consisted of determining the retail generation cost responsibility associated with serving FPL's existing load obligation without the LCEC load. Certain assumptions and forecasts were utilized such as load forecasts, fuel forecasts, costs of existing facilities, generation additions etc. The second scenario, or "LCEC Case," consisted of determining the retail generation cost responsibility associated with serving FPL's existing load obligation with the addition of LCEC's load. The assumptions and forecasts utilized in the LCEC Case were consistent with the Base Case, with the exception that certain additional generation resources were identified for FPL's system as a result of serving the LCEC load. The difference in retail cost responsibility between the LCEC Case and the Base Case represented the effect on retail customers associated with serving the LCEC load. If the retail cost responsibility in the LCEC Case is not greater than in the Base Case then one can conclude that the FPL retail customers were not negatively impacted by entering into the Agreement.

FPL performed this analysis in July of 2007, prior to executing the Agreement with LCEC. The analysis showed a favorable impact to FPL's retail customers of approximately $110 million (nominal) through 2020. Although the term of the Agreement extends out to 2033, there is considerable uncertainty beyond 2020 as to the amount and type of generation that will be needed to meet FPL's total load obligations. Thus, FPL focused its analysis on the years from 2010 to 2020 as a representative time period: it covers the full duration of the current (2008) Ten Year Site Plan; and it also includes all of FPL's currently identified unit additions (the last being the proposed Turkey Point nuclear generation additions in 2018 and 2020).

The results of FPL's analysis are summarized in the following table:

			Retail Impact	
	Base Case Resource plan	LCEC Case Resource Plan	Yearly	Cumulative
Year			Millions $	Millions $
2010	WCEC 2	WCEC 2	(7)	(7)
2011	104 MW Nuclear Upgrade	WCEC 3, 104 MW Nuclear Upgrade	36	29
2012	WCEC 3, 304 MW Nuclear Upgrade	304 MW Nuclear Upgrade	(22)	7
2013	----	----	7	14
2014	----	CC	28	43
2015	CC	CC	(38)	4
2016	CC	CC	16	21
2017	CC	CC	2	23
2018	TP 6 nuclear	TP 6 nuclear	12	35
2019	---	---	32	68
2020	TP 7 nuclear	TP 7 nuclear	42	110

Q. Did FPL's analysis evaluate the impact of the Agreement on retail customers beyond 2020?

A. Yes. As shown in my Exhibit TWG-2, the analysis evaluated the impact of the Agreement on retail customers through 2033, assuming a mix of generation additions beyond 2020 that FPL considered to be potentially viable technologies in that time period. This included assumed additions of gas-fired combined cycle units, integrated gasification combined cycle units and nuclear units. The longer term results shown in Exhibit TWG – 2 reinforce the conclusion one can draw from the results through 2020: the Agreement is consistent with the interests of FPL's retail customers. I want to caution again, however, that the results of the analysis are necessarily more uncertain the further one goes out in time, especially into periods beyond the time horizon of FPL's currently identified unit additions.

Q. **Has FPL updated the July 2007 analysis to reflect current assumptions?**

A. Yes. In preparation for this filing, FPL performed an updated analysis in August of 2008 of the retail rate impact through 2020, using the most recent forecasts for load, fuel and generation plans. The updated analysis continues to show a favorable impact to FPL's retail customers, with the cumulative benefit increasing to approximately $435 million (nominal) through 2020 from the $110 million nominal cumulative benefit shown in the July 2007 analysis.

The results of the updated analysis are summarized in the following table:

			Retail Impact	
	Base Case Resource Plan	LCEC Case Resource Plan	Yearly	Cumulative
Year			Millions $	Millions $
2010	WCEC 2	WCEC 2	(22)	(22)
2011	WCEC 3	WCEC 3	8	(15)
2012	---	---	10	(4)
2013	PCC conversion	PCC conversion	16	12
2014	PRV conversion	PRV conversion	78	90
2015	---	---	86	175
2016	---	---	73	248
2017	---	---	63	311
2018	TP 6 nuclear	TP 6 nuclear	55	366
2019	---	---	40	405
2020	TP 7 nuclear	TP 7 nuclear	29	435

This updated analysis provides additional confidence that the Agreement is consistent with the interests of FPL's retail customers.

Q. **Please summarize your testimony.**

A. The Agreement benefits LCEC customers by providing them with reliable, cost-effective power and increased diversity in the sources of that power, without being disadvantageous to FPL's own retail customers. The Agreement is thus a "win – win" proposition for LCEC, FPL's customers and the state of Florida as a whole. The Commission should confirm that it concurs with these conclusions so that FPL can move forward with implementing the Agreement.

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

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased power Cost Recovery Clause and Generating Performance Incentive Factor	DOCKET NO. 080001-EI FILED: September 2, 2008

AFFIDAVIT

STATE OF FLORIDA
COUNTY OF MIAMI-DADE

BEFORE ME, the undersigned authority, personally appeared Renae B. Deaton, who being first duly sworn deposes and says:

1. My name is Renae B. Deaton. I am employed by Florida Power & Light Company ("FPL"). My business address is 9250 West Flagler St., Miami, Florida, 33174.

2. I hold a Bachelor of Science in business administration and a Masters of Business Administration from Charleston Southern University. Since joining FPL in 1998 I have held positions in the rates and regulatory areas. Prior to joining FPL, I was employed at the South Carolina Public Service Authority (d/b/a Santee Cooper) for fourteen years where I held a variety of positions in the Corporate Forecasting, Rates, and Marketing Department and in generation plant operations.

3. I currently hold the position of Rate Development Manager with responsibilities for rate development and tariff administration.

4. The purpose of my affidavit is to submit for the Commission's confirmation the revisions to FPL's rates and charges resulting from application of the revised Generation Base Rate Adjustment ("GBRA") Factor for true-up of Turkey Point Unit 5 costs to be applied to meter readings made on and after January 1, 2009, and application of the initial GBRA factors resulting from the commercial operation of WCEC Units 1 and 2 to be applied to meter readings made on and after June 1 and November 1, 2009, respectively. Also, I provide the amount to be refunded through the Capacity Cost Recovery Clause ("CCRC") in order to adjust base revenues for the difference between the cumulative base revenues that have been or will have been collected since the implementation of the initial GBRA Factor on May 1, 2007 through December 30, 2008 and the cumulative base revenues that would have resulted if the revised GBRA Factor had been implemented on May 1, 2007.

Revised GBRA for True-up of Turkey Point Unit 5 costs

5. The Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-05-0902-S-EI, issued September 14, 2005 in Docket 050045-EI ("Settlement Agreement"), provided for a GBRA factor to be applied to FPL's rates upon the commercial in-service date of any power plant that is approved pursuant to the Florida Power Plant Siting Act ("PPSA") within the term of the Settlement Agreement. In Order No. PSC-06-1057-FOF-EI, the Commission approved the initial GBRA Factor for Turkey Point Unit 5 of 3.271%. This initial GBRA Factor was determined using the estimate of capital cost from the Turkey Point Unit 5 need determination.

6. As discussed in the affidavit of Dr. Morley dated September 1, 2006 in Docket No. 060001-EI ("Dr. Morley Affidavit") and pursuant to the Settlement

Agreement, once the actual capital costs of Turkey Point Unit 5 are known, a revised GBRA Factor is to be computed using the same data and methodology incorporated in the initial GBRA Factor, with the exception that Turkey Point Unit 5's actual capital costs will be used in lieu of the capital cost upon which the need determination was based.

7. Pursuant to the Settlement Agreement, the GBRA is to be implemented by adjusting base charges and non-clause recoverable credits (e.g. the transformer rider credits and the curtailable service credits) by an equal percentage. The calculation of this percentage change in rates is based on the ratio of Turkey Point Unit 5's jurisdictional annual revenue requirement and the forecasted retail base revenues from the sales of electricity during the first twelve months of the unit's operation. This ratio is the GBRA Factor. The revised GBRA Factor is applied to FPL's current base charges and non-clause recoverable credits, adjusted to remove the initial GBRA Factor, to produce the revised base rate charges. I describe below in more detail the computation of the revised GBRA Factor.

8. The base revenue requirement revised for Turkey Point Unit 5's actual capital costs for the first twelve months of Turkey Point Unit 5's operation of $123.22 million was provided by the accounting department based on FPL's books and records. The Jurisdictional Separation Factors consistent with the separation of costs incorporated in Docket 050045-EI are applied to this figure. As shown in Document No. RBD-1, the resulting jurisdictional revenue requirement is $121.31 million.

9. Except for the revenue requirements associated with the actual capital costs, the revised GBRA Factor is computed using the same data used in the computation

of the initial GBRA Factor. This data includes billed retail base revenues from the sales of electricity and unbilled retail base revenues in the amount of $3,876.80 million. This data is shown in Document No. RBD-2 and is the same as that shown in Dr. Morley's Affidavit.

10. The revised GBRA Factor is calculated based on the ratio of Turkey Point Unit 5's jurisdictional annual revenue requirement and the total retail base revenues from the sales of electricity over the first twelve months of Turkey Point Unit 5's commercial operation. The computation and resulting GBRA Factor is provided in Document No. RBD-3. Document No. RBD-4 shows the revised charges that result from removing the initial GBRA factor of 3.271%, and applying the revised GBRA Factor of 3.129% to FPL's current base charges and non-clause recoverable credits. These new charges will be applied to meter readings made on and after December 31, 2008.

11. Pursuant to the settlement agreement and consistent with the Dr. Morley Affidavit, once Turkey Point Unit 5's actual capital costs are known, if the unit's actual capital costs are less than the projected costs used to develop the initial GBRA Factor, a one-time credit is to be made through the capacity clause. The difference between the cumulative base revenues that have been or will have been collected since the implementation of the initial GBRA Factor on May 1, 2007 through December 30, 2008 and the cumulative base revenues that would have resulted if the revised GBRA Factor had been implemented on May 1, 2007 will be credited to customers through the CCRC with interest at the 30-day commercial paper rate as specified in Rule 25-6.109. The amount of the refund with interest is $9.30 million and is shown on Document No. RBD-5.

WCEC Unit 1

12. As presented in Dr. Sim's affidavit, the projected base revenue requirement for the first twelve months of WCEC Unit 1's operation is $140.70 million. The Jurisdictional Separation Factors consistent with the separation of costs incorporated in Docket 050045-EI are applied to this figure. As shown in Document No. RBD-6, the resulting jurisdictional revenue requirement is $138.52 million.

13. The GBRA Factor also requires computation of the retail base revenues from the sales of electricity during the first twelve months of WCEC Unit 1's commercial operation. Billed retail base revenues from the sales of electricity have been projected using the same load forecast incorporated in the Company's current capacity clause filing. Document No. RBD-7 shows the billed retail base revenues from the sales of electricity for the period June 2009 through May 2010 for all customer classes. Billed retail base revenues from the sales of electricity include customer, demand and energy charge revenues and non-clause recoverable credits. Thus, all the charges subject to the GBRA Factor are included in this revenue figure. In addition, unbilled retail base revenues are included in total retail base revenues from the sales of electricity in order to account for the collection lag resulting from the billing cycle. As shown in Document No. RBD-7, the total retail base revenues from the sales of electricity over the first twelve months of WCEC Unit 1's commercial operation are projected be $3,866.34 million.

14. The GBRA Factor is calculated based on the ratio of WCEC Unit 1's jurisdictional annual revenue requirement and the total retail base revenues from the sales of electricity over the first twelve months of WCEC Unit 1's commercial operation. The computation and resulting GBRA Factor of 3.583%, is provided in Document No. RBD-

8. Document No. RBD-9 shows the revised charges that result from applying the GBRA Factor to FPL's current base charges and non-clause recoverable credits. Pursuant to the Settlement Agreement, these new charges will be applied to meter readings made on and after the commercial in service date of WCEC Unit 1, currently projected to occur in June 2009. FPL will submit for the FPSC staffs administrative approval revised tariff sheets reflecting these new charges prior to the actual commercial in service date.

15. Once WCEC Unit 1's actual capital costs are known, if the unit's actual capital costs are less than the projected costs used to develop the initial GBRA Factor for WCEC Unit 1, a one-time credit will be made through the capacity clause. In order to determine the amount of this credit a revised GBRA Factor will be computed using the same data and methodology incorporated into the initial GBRA Factor, with the exception that WCEC Unit 1's actual capital costs will be used in lieu of the capital cost the need determination was based on. On a going forward basis, base rates will be adjusted to reflect the revised GBRA Factor for WCEC Unit 1. The difference between the cumulative base revenues since the implementation of the initial GBRA Factor and the cumulative base revenues that would have resulted if the revised GBRA Factor had been implemented during the same time period will be credited to customers through the capacity clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109.

WCEC Unit 2

16. As presented in Dr. Sim's affidavit, the base revenue requirement for the first twelve months of WCEC Unit 2's operation is $129.10 million. The Jurisdictional Separation Factors consistent with the separation of costs incorporated in Docket 050045-

E1 are applied to this figure. As shown in Document No. RBD-10, the resulting jurisdictional revenue requirement is $127.10 million.

17. The GBRA Factor also requires computation of the retail base revenues from the sales of electricity during the first twelve months of WCEC Unit 2's commercial operation. Billed retail base revenues from the sales of electricity have been projected using the same load forecast incorporated in the Company's current capacity clause filing. Document No. RBD-11 shows the billed retail base revenues from the sales of electricity for the period November 2009 through October 2010 for all customer classes. Billed retail base revenues from the sales of electricity include customer, demand and energy charge revenues and non-clause recoverable credits. Thus, all the charges subject to the GBRA Factor are included in this revenue figure. In addition, unbilled retail base revenues are included in total retail base revenues from the sales of electricity in order to account for the collection lag resulting from the billing cycle. As shown in Document No. RBD-11, the total retail base revenues from the sales of electricity over the first twelve months of WCEC Unit 2's commercial operation are projected be $4,030.30 million.

18. The GBRA Factor is calculated based on the ratio of WCEC Unit 2's jurisdictional annual revenue requirement and the total retail base revenues from the sales of electricity over the first twelve months of WCEC Unit 2's commercial operation. The computation and resulting GBRA Factor, 3.154%, is provided in Document No. RBD-12. Document No. RBD-13 shows the revised charges that result from applying the GBRA Factor to FPL's current base charges and non-clause recoverable credits. Pursuant to the Settlement Agreement, these new charges will be applied to meter readings made on and after the commercial in service date of WCEC Unit 2, currently projected to occur in

November 2009. FPL will submit for the FPSC staffs administrative approval revised tariff sheets reflecting these new charges prior to the actual commercial in service date.

19. Once WCEC Unit 2's actual capital costs are known, if the unit's actual capital costs are less than the projected costs used to develop the initial GBRA Factor for WCEC Unit 2, a one-time credit will be made through the capacity clause. In order to determine the amount of this credit a revised GBRA Factor will be computed using the same data and methodology incorporated into the initial GBRA Factor, with the exception that WCEC Unit 2's actual capital costs will be used in lieu of the capital cost the need determination was based on. On a going forward basis, base rates will be adjusted to reflect the revised GBRA Factor for WCEC Unit 2. The difference between the cumulative base revenues since the implementation of the initial GBRA Factor and the cumulative base revenues that would have resulted if the revised GBRA Factor had been implemented during the same time period will be credited to customers through the capacity clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109.

Renae B. Deaton

I hereby certify that on this 19th day of August, 2008 before me, an officer duly authorized in the State and County aforesaid to take acknowledgements, personally appeared Renae Deaton who is personally known to me, and she acknowledge before me that she executed this certification of signature as her free act and deed who did not take an oath.

I witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as this 19th day of August, 2008.

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

Monica Lynn Padron

Notary Public

State of Florida

My Commission Expires: 12/18/10

Separation Of Turkey Point Costs

	System ($million)	Jurisdictional Factor	($million)
Capital Revenue Requirement	$110.47	98.451%	$108.76
Fixed O&M and Capital Replacement	11.67	98.439%	11.49
Variable O&M	1.07	98.439%	1.06
Total Revenue Requirement	$123.22	98.450%	$121.31

Docket No. 080001-EI
R. Deaton, Exhibit No. ______
Document No. RBD-2, Page 1 of 1
Retail Base Revenues For The First 12 Months Of Turkey Point Unit 5's Commercial Operation

Customer Class	2007 May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	$177,556,790	$211,709,515	$232,135,575	$234,491,009	$231,376,796	$213,325,680	$182,470,240	$182,607,690
Commercial	$110,034,335	$116,414,425	$119,549,579	$120,386,791	$121,202,000	$117,655,699	$110,678,360	$109,159,045
Industrial	$6,721,581	$7,336,634	$6,595,864	$7,019,631	$7,090,561	$6,856,521	$7,053,774	$6,722,891
Street & Highway	$3,609,645	$3,614,911	$3,620,177	$3,625,443	$3,630,924	$3,636,405	$3,641,886	$3,647,641
Other	$126,828	$129,824	$131,444	$131,569	$131,630	$129,618	$126,163	$123,398
Railroads & Railways	$216,036	$234,346	$228,319	$229,827	$235,330	$234,390	$229,719	$223,926
Total Billed Retail Base Revenue	$298,265,216	$339,439,654	$362,260,957	$365,884,269	$363,667,242	$341,838,313	$304,200,143	$302,484,591

Customer Class	2008 Jan	Feb	Mar	Apr	12 Month Ending
Residential	$201,744,675	$172,631,949	$171,395,250	$166,113,281	$2,377,558,448
Commercial	$109,533,074	$105,899,180	$109,009,271	$111,100,421	$1,360,622,179
Industrial	$6,808,629	$7,175,460	$6,966,301	$6,893,599	$83,241,446
Street & Highway	$3,653,396	$3,659,151	$3,665,870	$3,672,590	$43,678,040
Other	$121,682	$121,175	$122,327	$124,222	$1,519,880
Railroads & Railways	$220,945	$216,351	$228,473	$227,502	$2,725,164
Total Billed Retail Base Revenue	$322,082,401	$289,703,266	$291,387,491	$288,131,614	$3,869,345,157

	12 Month Ending
Total Billed Retail Base Revenues From the Sales of Electricity	$3,869,345,157
Unbilled Retail Base Revenues	$7,457,421
Total Retail Base Revenues From the Sales of Electricity	$3,876,802,579

Note: Totals may not add due to rounding.

GBRA FACTOR

	($million)	source
Jurisdictional Annualized Revenue Requirement	$121.31	Doc. No. RBD-1 - trueup
Total Retail Base Revenues From the Sales of Electricity	$3,876.80	Doc. No. RBD-2 as filed
REVISED GBRA FACTOR [(A) / (B)]	3.129%	
INITIAL GBRA FACTOR as filed	3.271%	
Delta	-0.142%	

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
RS-1	Residential Service				
	Customer Charge/Minimum	$5.17	$5.34	$5.33	-0.2%
	Base Energy Charge (¢ per kWh)				
	First 1,000 kWh	3.295	3.403	3.398	-0.1%
	All additional kWh	4.295	4.435	4.429	-0.1%
RST-1	Residential Service -Time of Use				
	Customer Charge/Minimum	$8.20	$8.47	$8.46	-0.1%
	with Lump-sum metering payment	$5.17	$5.34	$5.33	-0.2%
	Base Energy Charge (¢ per kWh)				
	On-Peak	6.914	7.140	7.130	-0.1%
	Off-Peak	2.123	2.192	2.189	-0.1%
	Lump-sum payment for time of use metering cost	$145.60	$150.36	$150.16	-0.1%
GS-1	General Service - Non Demand (0-20 kW)				
	Customer Charge/Minimum				
	Metered	$8.24	$8.51	$8.50	-0.1%
	Unmetered	$5.49	$5.67	$5.66	-0.2%
	Base Energy Charge (¢ per kWh)	3.802	3.927	3.921	-0.2%
GST-1	General Service - Non Demand - Time of Use (0-20 kW)				
	Customer Charge/Minimum	$11.27	$11.64	$11.62	-0.2%
	with Lump-sum metering payment	$8.24	$8.51	$8.50	-0.1%
	Base Energy Charge (¢ per kWh)				
	On-Peak	7.431	7.674	7.664	-0.1%
	Off-Peak	2.143	2.213	2.210	-0.1%
	Lump-sum payment for time of use metering cost	$145.60	$150.36	$150.16	-0.1%
GSD-1	General Service Demand (21-499 kW)				
	Customer Charge	$32.05	$33.10	$33.05	-0.2%
	Demand Charge ($/kW)				
	Demand Charge - All kW ($/kW)	$4.94	$5.10	$5.09	-0.2%
	Base Energy Charge (¢ per kWh)	1.348	1.392	1.390	-0.1%
	Minimum	$135.79	$140.20	$139.94	-0.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
GSDT-1	General Service Demand - Time of Use (21-499 kW)				
	Customer Charge	$38.00	$39.24	$39.19	-0.1%
	with Lump-sum metering payment	$32.05	$33.10	$33.05	-0.2%
	Demand Charge - On-Peak ($/kW)	$4.94	$5.10	$5.09	-0.2%
	Base Energy Charge (¢ per kWh)				
	On-Peak	3.146	3.249	3.244	-0.2%
	Off-Peak	0.865	0.893	0.892	-0.1%
	Lump-sum payment for time of use metering cost	$354.39	$365.98	$365.48	-0.1%
GSLD-1	General Service Large Demand (500-1999 kW)				
	Customer Charge	$37.55	$38.78	$38.72	-0.2%
	Demand Charge ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)	1.067	1.102	1.100	-0.2%
	Mimimum	$2,897.55	$2,993.78	$2,988.72	-0.2%
GSLDT-1	General Service Large Demand - Time of Use (500-1999 kW)				
	Customer Charge	$37.55	$38.78	$38.72	-0.2%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)				
	On-Peak	2.113	2.182	2.179	-0.1%
	Off-Peak	0.641	0.662	0.661	-0.2%
	Mimimum	$2,897.55	$2,993.78	$2,988.72	-0.2%
CS-1	Curtailable Service (500-1999 kW)				
	Customer Charge	$100.74	$104.04	$103.89	-0.1%
	Demand Charge ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)	1.068	1.103	1.101	-0.2%
	Monthly Credit ($ per kW)	($1.56)	($1.61)	($1.61)	0.0%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
CS-1	Curtailable Service (500-1999 kW) (continued)				
	Charges for Non-Compliance of Curtailment Demand				
	Rebilling for last 36 months (per kW)	$1.56	$1.61	$1.61	0.0%
	Penalty Charge-current month (per kW)	$3.36	$3.47	$3.47	0.0%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	$1.02	0.0%
	Minimum	$2,960.74	$3,059.04	$3,053.89	-0.2%
CST-1	Curtailable Service -Time of Use (500-1999 kW)				
	Customer Charge	$100.74	$104.04	$103.89	-0.1%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)				
	On-Peak	2.114	2.183	2.180	-0.1%
	Off-Peak	0.641	0.662	0.661	-0.2%
	Monthly Credit (per kW)	($1.56)	($1.61)	($1.61)	0.0%
	Charges for Non-Compliance of Curtailment Demand				
	Rebilling for last 36 months (per kW)	$1.56	$1.61	$1.61	0.0%
	Penalty Charge-current month (per kW)	$3.36	$3.47	$3.47	0.0%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	$1.02	0.0%
	Minimum	$2,960.74	$3,059.04	$3,053.89	-0.2%
GSLD-2	General Service Large Demand (2000 kW +)				
	Customer Charge	$155.68	$160.77	$160.55	-0.1%
	Demand Charge ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)	1.064	1.099	1.097	-0.2%
	Minimum	$11,595.68	$11,980.77	$11,960.55	-0.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
GSLDT-2	General Service Large Demand - Time of Use (2000 kW +)				
	Customer Charge	$155.68	$160.77	$160.55	-0.1%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)				
	On-Peak	2.219	2.292	2.288	-0.2%
	Off-Peak	0.600	0.620	0.619	-0.2%
	Minimum	$11,595.68	$11,980.77	$11,960.55	-0.2%
CS-2	Curtailable Service (2000 kW +)				
	Customer Charge	$155.68	$160.77	$160.55	-0.1%
	Demand Charge ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)	1.064	1.099	1.097	-0.2%
	Monthly Credit (per kW)	($1.56)	($1.61)	($1.61)	0.0%
	Charges for Non-Compliance of Curtailment Demand				
	Rebilling for last 36 months (per kW)	$1.56	$1.61	$1.61	0.0%
	Penalty Charge-current month (per kW)	$3.36	$3.47	$3.47	0.0%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	$1.02	0.0%
	Minimum	$11,595.68	$11,980.77	$11,960.55	-0.2%
CST-2	Curtailable Service -Time of Use (2000 kW +)				
	Customer Charge	$155.68	$160.77	$160.55	-0.1%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)				
	On-Peak	2.222	2.295	2.292	-0.1%
	Off-Peak	0.600	0.620	0.619	-0.2%
	Monthly Credit (per kW)	($1.56)	($1.61)	($1.61)	0.0%
	Charges for Non-Compliance of Curtailment Demand				
	Rebilling for last 36 months (per kW)	$1.56	$1.61	$1.61	0.0%
	Penalty Charge-current month (per kW)	$3.36	$3.47	$3.47	0.0%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	$1.02	0.0%
	Minimum	$11,595.68	$11,980.77	$11,960.55	-0.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
GSLD-3	General Service Large Demand (2000 kW +)				
	Customer Charge	$366.30	$378.28	$377.76	-0.1%
	Demand Charge ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)	0.553	0.571	0.570	-0.2%
GSLDT-3	General Service Large Demand - Time of Use (2000 kW +)				
	Customer Charge	$366.30	$378.28	$377.76	-0.1%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)				
	On-Peak	0.615	0.635	0.634	-0.2%
	Off-Peak	0.493	0.509	0.508	-0.2%
CS-3	Curtailable Service (2000 kW +)				
	Customer Charge	$366.30	$378.28	$377.76	-0.1%
	Demand Charge ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)	0.553	0.571	0.570	-0.2%
	Monthly Credit (per kW)	($1.56)	($1.61)	($1.61)	0.0%
	Charges for Non-Compliance of Curtailment Demand				
	Rebilling for last 36 months (per kW)	$1.56	$1.61	$1.61	0.0%
	Penalty Charge-current month (per kW)	$3.36	$3.47	$3.47	0.0%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	$1.02	0.0%
CST-3	Curtailable Service -Time of Use (2000 kW +)				
	Customer Charge	$366.30	$378.28	$377.76	-0.1%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	$5.90	-0.2%
	Base Energy Charge (¢ per kWh)				
	On-Peak	0.615	0.635	0.634	-0.2%
	Off-Peak	0.493	0.509	0.508	-0.2%
	Monthly Credit (per kW)	($1.56)	($1.61)	($1.61)	0.0%
	Charges for Non-Compliance of Curtailment Demand				
	Rebilling for last 36 months (per kW)	$1.56	$1.61	$1.61	0.0%
	Penalty Charge-current month (per kW)	$3.36	$3.47	$3.47	0.0%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	$1.02	0.0%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
OS-2	Sports Field Service				
	Customer Charge/Minimum	$8.24	$8.51	$8.50	-0.1%
	Base Energy Charge (¢ per kWh)	5.656	5.841	5.833	-0.1%
MET	Metropolitan Transit Service				
	Customer Charge	$196.89	$203.33	$203.05	-0.1%
	Base Demand Charge ($/kW)	$9.57	$9.88	$9.87	-0.1%
	Base Energy Charge (¢ per kWh)	0.432	0.446	0.446	0.0%
CDR	Commercial/Industrial Demand Reduction Rider				
	Monthly Administrative Adder				
	GSD-1	$517.40	$534.32	$533.59	-0.1%
	GSDT-1	$511.45	$528.18	$527.45	-0.1%
	GSLD-1, GSLDT-1	$511.90	$528.64	$527.92	-0.1%
	GSLD-2, GSLDT-2	$393.77	$406.65	$406.09	-0.1%
	GSLD-3, GSLDT-3	$2,564.11	$2,647.98	$2,644.34	-0.1%
CILC-1	Commercial/Industrial Load Control Program				
	Customer Charge				
	(G) 200-499kW	$549.45	$567.42	$566.64	-0.1%
	(D) above 500kW	$549.45	$567.42	$566.64	-0.1%
	(T) transmission	$2,930.41	$3,026.26	$3,022.10	-0.1%
	Base Demand Charge ($/kW)				
	per kW of Max Demand All kW:				
	(G) 200-499kW	$2.17	$2.24	$2.24	0.0%
	per kW of Max Demand:				
	(D) above 500kW	$2.23	$2.30	$2.30	0.0%
	(T) transmission	None	None	None	N/A
	per kW of Load Control On-Peak:				
	(G) 200-499kW	$1.03	$1.06	$1.06	0.0%
	per kW of Load Control On-Peak:				
	(D) above 500kW	$1.06	$1.09	$1.09	0.0%
	(T) transmission	$1.05	$1.08	$1.08	0.0%
	per kW of Firm On-Peak Demand All kW:				
	(G) 200-499kW	$4.39	$4.53	$4.53	0.0%
	Per kW of Firm On-Peak Demand				
	(D) above 500kW	$5.36	$5.54	$5.53	-0.2%
	(T) transmission	$5.72	$5.91	$5.90	-0.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
CILC-1	Commercial/Industrial Load Control Program (continued)				
	Base Energy Charge (¢ per kWh)				
	On-Peak				
	(G) 200-499kW	0.949	0.980	0.979	-0.1%
	(D) above 500kW	0.660	0.682	0.681	-0.1%
	(T) transmission	0.487	0.503	0.502	-0.2%
	Off-Peak				
	(G) 200-499kW	0.949	0.980	0.979	-0.1%
	(D) above 500kW	0.660	0.682	0.681	-0.1%
	(T) transmission	0.487	0.503	0.502	-0.2%
SL-1	Street Lighting				
	Charges for FPL-Owned Units				
	Fixture				
	Sodium Vapor 5,800 lu 70 watts	$3.55	$3.67	$3.66	-0.3%
	Sodium Vapor 9,500 lu 100 watts	$3.62	$3.74	$3.73	-0.3%
	Sodium Vapor 16,000 lu 150 watts	$3.72	$3.84	$3.84	0.0%
	Sodium Vapor 22,000 lu 200 watts	$5.64	$5.82	$5.82	0.0%
	Sodium Vapor 50,000 lu 400 watts	$5.71	$5.90	$5.89	-0.2%
	* Sodium Vapor 12,800 lu 150 watts	$3.88	$4.01	$4.00	-0.2%
	* Sodium Vapor 27,500 lu 250 watts	$6.00	$6.20	$6.19	-0.2%
	* Sodium Vapor 140,000 lu 1,000 watts	$9.04	$9.34	$9.32	-0.2%
	* Mercury Vapor 6,000 lu 140 watts	$2.81	$2.90	$2.90	0.0%
	* Mercury Vapor 8,600 lu 175 watts	$2.84	$2.93	$2.93	0.0%
	* Mercury Vapor 11,500 lu 250 watts	$4.74	$4.90	$4.89	-0.2%
	* Mercury Vapor 21,500 lu 400 watts	$4.73	$4.88	$4.88	0.0%
	* Mercury Vapor 39,500 lu 700 watts	$6.68	$6.90	$6.89	-0.1%
	* Mercury Vapor 60,000 lu 1,000 watts	$6.85	$7.07	$7.06	-0.1%
	Maintenance				
	Sodium Vapor 5,800 lu 70 watts	$1.36	$1.40	$1.40	0.0%
	Sodium Vapor 9,500 lu 100 watts	$1.37	$1.41	$1.41	0.0%
	Sodium Vapor 16,000 lu 150 watts	$1.40	$1.45	$1.44	-0.7%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.85	$1.85	0.0%
	Sodium Vapor 50,000 lu 400 watts	$1.76	$1.82	$1.82	0.0%
	* Sodium Vapor 12,800 lu 150 watts	$1.56	$1.61	$1.61	0.0%
	* Sodium Vapor 27,500 lu 250 watts	$1.90	$1.96	$1.96	0.0%
	* Sodium Vapor 140,000 lu 1,000 watts	$3.47	$3.58	$3.58	0.0%
	* Mercury Vapor 6,000 lu 140 watts	$1.23	$1.27	$1.27	0.0%
	* Mercury Vapor 8,600 lu 175 watts	$1.23	$1.27	$1.27	0.0%
	* Mercury Vapor 11,500 lu 250 watts	$1.77	$1.83	$1.83	0.0%
	* Mercury Vapor 21,500 lu 400 watts	$1.75	$1.81	$1.80	-0.6%
	* Mercury Vapor 39,500 lu 700 watts	$2.96	$3.06	$3.05	-0.3%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
	* Mercury Vapor 60,000 lu 1,000 watts	$2.88	$2.97	$2.97	0.0%
SL-1	Street Lighting (continued)				
	Energy Non-Fuel+				
	Sodium Vapor 5,800 lu 70 watts	$0.59	$0.61	$0.61	0.0%
	Sodium Vapor 9,500 lu 100 watts	$0.83	$0.86	$0.86	0.0%
	Sodium Vapor 16,000 lu 150 watts	$1.22	$1.26	$1.26	0.0%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.84	$1.84	0.0%
	Sodium Vapor 50,000 lu 400 watts	$3.41	$3.52	$3.51	-0.3%
	* Sodium Vapor 12,800 lu 150 watts	$1.22	$1.26	$1.26	0.0%
	* Sodium Vapor 27,500 lu 250 watts	$2.35	$2.43	$2.43	0.0%
	* Sodium Vapor 140,000 lu 1,000 watts	$8.34	$8.61	$8.60	-0.1%
	* Mercury Vapor 6,000 lu 140 watts	$1.26	$1.30	$1.30	0.0%
	* Mercury Vapor 8,600 lu 175 watts	$1.57	$1.61	$1.61	0.0%
	* Mercury Vapor 11,500 lu 250 watts	$2.11	$2.18	$2.18	0.0%
	* Mercury Vapor 21,500 lu 400 watts	$3.25	$3.35	$3.35	0.0%
	* Mercury Vapor 39,500 lu 700 watts	$5.52	$5.70	$5.69	-0.2%
	* Mercury Vapor 60,000 lu 1,000 watts	$7.81	$8.07	$8.05	-0.2%
	Total Charge-Fixtures, Maintenance & Energy				
	* Incandescent 1,000 lu 103 watts	$6.90	$7.13	$7.12	-0.1%
	* Incandescent 2,500 lu 202 watts	$7.15	$7.38	$7.37	-0.1%
	* Incandescent 4,000 lu 327 watts	$8.37	$8.64	$8.63	-0.1%
	* Incandescent 6,000 lu 448 watts	$9.33	$9.64	$9.62	-0.2%
	* Incandescent 10,000 lu 690 watts	$11.23	$11.60	$11.58	-0.2%

* These units are closed to new FPL installations

+ The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the street light unit times the Proposed Non-Fuel Energy Rate
Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)

	Charge for Customer-Owned Units				
	Relamping and Energy				
	Sodium Vapor 5,800 lu 70 watts	$1.28	$1.32	$1.32	0.0%
	Sodium Vapor 9,500 lu 100 watts	$1.53	$1.58	$1.58	0.0%
	Sodium Vapor 16,000 lu 150 watts	$1.92	$1.98	$1.98	0.0%
	Sodium Vapor 22,000 lu 200 watts	$2.49	$2.57	$2.57	0.0%
	Sodium Vapor 50,000 lu 400 watts	$4.12	$4.25	$4.25	0.0%
	* Sodium Vapor 12,800 lu 150 watts	$2.15	$2.22	$2.22	0.0%
	* Sodium Vapor 27,500 lu 250 watts	$3.09	$3.19	$3.19	0.0%
	* Sodium Vapor 140,000 lu 1,000 watts	$9.98	$10.31	$10.29	-0.2%
	* Mercury Vapor 6,000 lu 140 watts	$1.95	$2.01	$2.01	0.0%
	* Mercury Vapor 8,600 lu 175 watts	$2.26	$2.33	$2.33	0.0%
	* Mercury Vapor 11,500 lu 250 watts	$2.85	$2.94	$2.94	0.0%
	* Mercury Vapor 21,500 lu 400 watts	$3.97	$4.10	$4.09	-0.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
	* Mercury Vapor 39,500 lu 700 watts	$7.08	$7.31	$7.30	-0.1%
SL-1	Street Lighting (continued)				
	* Mercury Vapor 60,000 lu 1,000 watts	$8.79	$9.08	$9.07	-0.1%
	* Incandescent 1,000 lu 103 watts	$2.45	$2.53	$2.53	0.0%
	* Incandescent 2,500 lu 202 watts	$3.16	$3.26	$3.26	0.0%
	* Incandescent 4,000 lu 327 watts	$4.12	$4.25	$4.25	0.0%
	* Incandescent 6,000 lu 448 watts	$4.97	$5.13	$5.13	0.0%
	* Incandescent 10,000 lu 690 watts	$6.85	$7.07	$7.06	-0.1%
	* Fluorescent 19,800 lu 300 watts	$3.38	$3.49	$3.49	0.0%
	* Fluorescent 39,600 lu 700 watts	$6.54	$6.75	$6.74	-0.1%
	Energy Only+				
	Sodium Vapor 5,800 lu 70 watts	$0.59	$0.61	$0.61	0.0%
	Sodium Vapor 9,500 lu 100 watts	$0.83	$0.86	$0.86	0.0%
	Sodium Vapor 16,000 lu 150 watts	$1.22	$1.26	$1.26	0.0%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.84	$1.84	0.0%
	Sodium Vapor 50,000 lu 400 watts	$3.41	$3.52	$3.51	-0.3%
	* Sodium Vapor 12,800 lu 150 watts	$1.22	$1.26	$1.26	0.0%
	* Sodium Vapor 27,500 lu 250 watts	$2.35	$2.43	$2.43	0.0%
	* Sodium Vapor 140,000 lu 1,000 watts	$8.34	$8.61	$8.60	-0.1%
	* Mercury Vapor 6,000 lu 140 watts	$1.26	$1.30	$1.30	0.0%
	* Mercury Vapor 8,600 lu 175 watts	$1.57	$1.61	$1.61	0.0%
	* Mercury Vapor 11,500 lu 250 watts	$2.11	$2.18	$2.18	0.0%
	* Mercury Vapor 21,500 lu 400 watts	$3.25	$3.35	$3.35	0.0%
	* Mercury Vapor 39,500 lu 700 watts	$5.52	$5.70	$5.69	-0.2%
	* Mercury Vapor 60,000 lu 1,000 watts	$7.81	$8.07	$8.05	-0.2%
	* Incandescent 1,000 lu 103 watts	$0.73	$0.75	$0.75	0.0%
	* Incandescent 2,500 lu 202 watts	$1.44	$1.49	$1.49	0.0%
	* Incandescent 4,000 lu 327 watts	$2.35	$2.43	$2.42	-0.4%
	* Incandescent 6,000 lu 448 watts	$3.20	$3.30	$3.30	0.0%
	* Incandescent 10,000 lu 690 watts	$4.95	$5.11	$5.10	-0.2%
	* Fluorescent 19,800 lu 300 watts	$2.47	$2.55	$2.55	0.0%
	* Fluorescent 39,600 lu 700 watts	$5.36	$5.54	$5.53	-0.2%
	Non-Fuel Energy (¢ per kWh)	2.029	2.095	2.092	-0.1%
	Other Charges				
	Wood Pole	$2.54	$2.62	$2.62	0.0%
	Concrete Pole	$3.49	$3.60	$3.60	0.0%
	Fiberglass Pole	$4.13	$4.27	$4.26	-0.2%
	Underground conductors not under paving (¢ per foot)	1.91	1.97	1.97	0.0%
	Underground conductors under paving (¢ per foot)	4.66	4.81	4.81	0.0%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
SL-1	Street Lighting (continued)				
* These units are closed to new FPL installations					
+ The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the street light unit times the Proposed Non-Fuel Energy Rate. Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)					
PL-1	Premium Lighting				
	Non-Fuel Energy (¢ per kWh)	2.029	2.095	2.092	-0.1%
OL-1	Outdoor Lighting				
	Charges for FPL-Owned Units				
	Fixture				
	Sodium Vapor 5,800 lu 70 watts	$4.06	$4.19	$4.19	0.0%
	Sodium Vapor 9,500 lu 100 watts	$4.17	$4.31	$4.30	-0.2%
	Sodium Vapor 16,000 lu 150 watts	$4.31	$4.45	$4.44	-0.2%
	Sodium Vapor 22,000 lu 200 watts	$6.27	$6.48	$6.47	-0.2%
	Sodium Vapor 50,000 lu 400 watts	$6.67	$6.89	$6.88	-0.1%
	* Sodium Vapor 12,000 lu 150 watts	$4.61	$4.76	$4.75	-0.2%
	* Mercury Vapor 6,000 lu 140 watts	$3.12	$3.22	$3.22	0.0%
	* Mercury Vapor 8,600 lu 175 watts	$3.14	$3.24	$3.24	0.0%
	* Mercury Vapor 21,500 lu 400 watts	$5.16	$5.33	$5.32	-0.2%
	Maintenance				
	Sodium Vapor 5,800 lu 70 watts	$1.36	$1.40	$1.40	0.0%
	Sodium Vapor 9,500 lu 100 watts	$1.37	$1.41	$1.41	0.0%
	Sodium Vapor 16,000 lu 150 watts	$1.40	$1.45	$1.44	-0.7%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.85	$1.85	0.0%
	Sodium Vapor 50,000 lu 400 watts	$1.76	$1.82	$1.82	0.0%
	* Sodium Vapor 12,000 lu 150 watts	$1.56	$1.61	$1.61	0.0%
	* Mercury Vapor 6,000 lu 140 watts	$1.23	$1.27	$1.27	0.0%
	* Mercury Vapor 8,600 lu 175 watts	$1.23	$1.27	$1.27	0.0%
	* Mercury Vapor 21,500 lu 400 watts	$1.75	$1.81	$1.80	-0.6%
	Energy Non-Fuel+				
	Sodium Vapor 5,800 lu 70 watts	$0.59	$0.61	$0.61	0.0%
	Sodium Vapor 9,500 lu 100 watts	$0.84	$0.86	$0.86	0.0%
	Sodium Vapor 16,000 lu 150 watts	$1.22	$1.26	$1.26	0.0%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.85	$1.84	-0.5%
	Sodium Vapor 50,000 lu 400 watts	$3.41	$3.52	$3.52	0.0%
	* Sodium Vapor 12,000 lu 150 watts	$1.22	$1.26	$1.26	0.0%
	* Mercury Vapor 6,000 lu 140 watts	$1.26	$1.30	$1.30	0.0%
	* Mercury Vapor 8,600 lu 175 watts	$1.57	$1.61	$1.61	0.0%
	* Mercury Vapor 21,500 lu 400 watts	$3.25	$3.36	$3.35	-0.3%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
OL-1	Outdoor Lighting (continued)				
	Charges for Customer Owned Units				
	Total Charge-Relamping & Energy				
	Sodium Vapor 5,800 lu 70 watts	$1.28	$1.32	$1.32	0.0%
	Sodium Vapor 9,500 lu 100 watts	$1.54	$1.59	$1.59	0.0%
	Sodium Vapor 16,000 lu 150 watts	$1.92	$1.98	$1.98	0.0%
	Sodium Vapor 22,000 lu 200 watts	$2.48	$2.56	$2.56	0.0%
	Sodium Vapor 50,000 lu 400 watts	$4.12	$4.25	$4.25	0.0%
	* Sodium Vapor 12,000 lu 150 watts	$2.15	$2.22	$2.22	0.0%
	* Mercury Vapor 6,000 lu 140 watts	$1.95	$2.01	$2.01	0.0%
	* Mercury Vapor 8,600 lu 175 watts	$2.26	$2.33	$2.33	0.0%
	* Mercury Vapor 21,500 lu 400 watts	$3.97	$4.10	$4.09	-0.2%
	Energy Only[+]				
	Sodium Vapor 5,800 lu 70 watts	$0.59	$0.61	$0.61	0.0%
	Sodium Vapor 9,500 lu 100 watts	$0.84	$0.86	$0.86	0.0%
	Sodium Vapor 16,000 lu 150 watts	$1.22	$1.26	$1.26	0.0%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.85	$1.84	-0.5%
	Sodium Vapor 50,000 lu 400 watts	$3.41	$3.52	$3.52	0.0%
	* Sodium Vapor 12,000 lu 150 watts	$1.22	$1.26	$1.26	0.0%
	* Mercury Vapor 6,000 lu 140 watts	$1.26	$1.30	$1.30	0.0%
	* Mercury Vapor 8,600 lu 175 watts	$1.57	$1.61	$1.61	0.0%
	* Mercury Vapor 21,500 lu 400 watts	$3.25	$3.36	$3.35	-0.3%

* These units are closed to new FPL installations

[+] The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the outdoor light unit times the Proposed Non-Fuel Energy Rate
Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)

	Non-Fuel Energy (¢ per kWh)	2.031	2.097	2.095	-0.1%
	Other Charges				
	Wood Pole	$3.18	$3.28	$3.28	0.0%
	Concrete Pole	$4.29	$4.43	$4.42	-0.2%
	Fiberglass Pole	$5.03	$5.19	$5.19	0.0%
	Underground conductors excluding Trenching per foot	$0.015	$0.015	$0.015	0.0%
	Down-guy, Anchor and Protector	$1.85	$1.91	$1.91	0.0%
SL-2	Traffic Signal Service				
	Base Energy Charge (¢ per kWh)	3.311	3.419	3.414	-0.1%
	Minimum charge at each point	$2.61	$2.70	$2.69	-0.4%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
SST-1	Standby and Supplemental Service				
	Customer Charge				
	SST-1(D1)	$123.63	$127.67	$127.50	-0.1%
	SST-1(D2)	$123.63	$127.67	$127.50	-0.1%
	SST-1(D3)	$178.57	$184.41	$184.16	-0.1%
	SST-1(T)	$389.19	$401.92	$401.37	-0.1%
	Distribution Demand $/kW Contract Standby Demand				
	SST-1(D1)	$1.96	$2.02	$2.02	0.0%
	SST-1(D2)	$2.30	$2.38	$2.37	-0.4%
	SST-1(D3)	$2.02	$2.09	$2.08	-0.5%
	SST-1(T)	N/A	N/A	N/A	N/A
	Reservation Demand $/kW				
	SST-1(D1)	$0.73	$0.75	$0.75	0.0%
	SST-1(D2)	$0.72	$0.74	$0.74	0.0%
	SST-1(D3)	$0.72	$0.74	$0.74	0.0%
	SST-1(T)	$0.70	$0.72	$0.72	0.0%
	Daily Demand (On-Peak) $/kW				
	SST-1(D1)	$0.34	$0.35	$0.35	0.0%
	SST-1(D2)	$0.33	$0.34	$0.34	0.0%
	SST-1(D3)	$0.33	$0.34	$0.34	0.0%
	SST-1(T)	$0.33	$0.34	$0.34	0.0%
	Non-Fuel Energy - On-Peak (¢ per kWh)				
	SST-1(D1)	0.685	0.707	0.706	-0.1%
	SST-1(D2)	0.702	0.725	0.724	-0.1%
	SST-1(D3)	0.694	0.717	0.716	-0.1%
	SST-1(T)	0.628	0.649	0.648	-0.2%
	Non-Fuel Energy - Off-Peak (¢ per kWh)				
	SST-1(D1)	0.685	0.707	0.706	-0.1%
	SST-1(D2)	0.702	0.725	0.724	-0.1%
	SST-1(D3)	0.694	0.717	0.716	-0.1%
	SST-1(T)	0.628	0.649	0.648	-0.2%
ISST-1	Interruptible Standby and Supplemental Service				
	Customer Charge				
	Distribution	$572.34	$591.06	$590.25	-0.1%
	Transmission	$2,953.31	$3,049.91	$3,045.72	-0.1%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
ISST-1	Interruptible Standby and Supplemental Service (continued)				
	Distribution Demand				
	Distribution	$2.23	$2.30	$2.30	0.0%
	Transmission	N/A	N/A	N/A	N/A
	Reservation Demand-Interruptible				
	Distribution	$0.15	$0.15	$0.15	0.0%
	Transmission	$0.14	$0.14	$0.14	0.0%
	Reservation Demand-Firm				
	Distribution	$0.72	$0.74	$0.74	0.0%
	Transmission	$0.70	$0.72	$0.72	0.0%
	Daily Demand (On-Peak) Firm Standby				
	Distribution	$0.33	$0.34	$0.34	0.0%
	Transmission	$0.33	$0.34	$0.34	0.0%
	Daily Demand (On-Peak) Interruptible Standby				
	Distribution	$0.07	$0.07	$0.07	0.0%
	Transmission	$0.07	$0.07	$0.07	0.0%
	Non-Fuel Energy - On-Peak (¢ per kWh)				
	Distribution	0.691	0.714	0.713	-0.1%
	Transmission	0.487	0.503	0.502	-0.2%
	Non-Fuel Energy - Off-Peak (¢ per kWh)				
	Distribution	0.691	0.714	0.713	-0.1%
	Transmission	0.487	0.503	0.502	-0.2%
WIES-1	Wireless Internet Electric Service				
	Non-Fuel Energy (¢ per kWh)	17.538	18.112	18.087	-0.1%
TR	Transformation Rider				
	Transformer Credit (per kW of Billing Demand)	($0.36)	($0.37)	($0.37)	0.0%
GSCU-1	GENERAL SERVICE CONSTANT USAGE				
	Customer Charge:	$9.14	$9.44	$9.43	-0.1%
	Non-Fuel Energy Charges:				
	Base Energy Charge (¢ per kWh)*	2.371	2.449	2.445	-0.1%

* The non-fuel energy charges will be assessed on the Constant Usage kWh

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) RATE PRIOR TO TP5 GBRA	(4) CURRENT RATE	(5) PROPOSED RATE	(6) PERCENT INCREASE [((5) - (4)) / (4)]
SDTR	SEASONAL DEMAND -TIME OF USE RIDER (continued)				
	Non-Fuel Energy Charges (¢ per kWh):				
	Base Seasonal Off-Peak kWh				
	For customers with an Annual Maximum Demand 21 - 499 kW:	1.028	1.062	1.060	-0.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.814	0.841	0.839	-0.2%
	For customers with an Annual Maximum Demand 2000+ kW:	0.811	0.838	0.836	-0.2%
	Base Seasonal On-Peak kWh				
	For customers with an Annual Maximum Demand 21 - 499 kW:	3.890	4.017	4.012	-0.1%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	2.978	3.075	3.071	-0.1%
	For customers with an Annual Maximum Demand 2000+ kW:	2.970	3.067	3.063	-0.1%
	OPTION A: Non-Seasonal Standard Rate				
	Demand Charges:				
	Non-Seasonal Demand Charge per kW of Non-Seasonal Maximum Demand:				
	For customers with an Annual Maximum Demand 21 - 499 kW:	$4.64	$4.79	$4.79	0.0%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$5.53	$5.71	$5.70	-0.2%
	For customers with an Annual Maximum Demand 2000+ kW:	$5.53	$5.71	$5.70	-0.2%
	Non-Fuel Energy Charges: (¢ per Non-Seasonal kWh)				
	Non-Seasonal Energy Charge:				
	For customers with an Annual Maximum Demand 21 - 499 kW:	1.348	1.392	1.390	-0.1%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	1.067	1.102	1.100	-0.2%
	For customers with an Annual Maximum Demand 2000+ kW:	1.064	1.099	1.097	-0.2%
	OR				
	OPTION B: Non-Seasonal Time of Use Rate				
	Demand Charges per kW of Non-Seasonal Demand occurring during the Non-Seasonal On-Peak period:				
	Non-Seasonal Demand Charge :				
	For customers with an Annual Maximum Demand 21 - 499 kW:	$4.64	$4.79	$4.79	0.0%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$5.53	$5.71	$5.70	-0.2%
	For customers with an Annual Maximum Demand 2000+ kW:	$5.53	$5.71	$5.70	-0.2%
	OPTION B: Non-Seasonal Time of Use Rate				
	Non-Fuel Energy Charges: (¢ per kWh)				
	Non-Seasonal On-Peak kWh				
	For customers with an Annual Maximum Demand 21 - 499 kW:	3.146	3.249	3.244	-0.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	2.113	2.182	2.179	-0.1%
	For customers with an Annual Maximum Demand 2000+ kW:	2.219	2.292	2.288	-0.2%
	Non-Seasonal Off-Peak kWh				
	For customers with an Annual Maximum Demand 21 - 499 kW:	0.865	0.893	0.892	-0.1%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.641	0.662	0.661	-0.2%
	For customers with an Annual Maximum Demand 2000+ kW:	0.600	0.620	0.619	-0.2%

PROVISION FOR REFUND INTEREST

	REFUND ACCRUAL	CUMULATIVE REFUND	INTEREST RATE	CUM. REFUND WITH INTEREST	MONTHLY INTEREST	CUMULATIVE INTEREST
Jan-07	0	0	0.0043875	0	0	0
Feb-07	0	0	0.0043875	0	0	0
Mar-07	0	0	0.0043917	0	0	0
Apr-07	158	158	0.0043875	159	0	0
May-07	428	586	0.0043833	588	2	2
Jun-07	488	1,075	0.0043875	1,080	4	6
Jul-07	505	1,580	0.0043792	1,591	6	11
Aug-07	559	2,139	0.0045375	2,159	8	20
Sep-07	517	2,655	0.0044458	2,686	11	31
Oct-07	469	3,124	0.0040708	3,167	12	43
Nov-07	389	3,513	0.0039458	3,569	13	56
Dec-07	379	3,892	0.0040542	3,963	15	71
Jan-08	380	4,272	0.0033583	4,357	14	85
Feb-08	363	4,635	0.0025708	4,732	12	97
Mar-08	386	5,021	0.0023833	5,130	12	108
Apr-08	409	5,430	0.0022792	5,551	12	121
May-08	453	5,883	0.0020333	6,015	12	132
Jun-08	499	6,382	0.0021958	6,528	14	146
Jul-08	523	6,905	0.0021958	7,066	15	161
Aug-08	538	7,444	0.0021958	7,621	16	177
Sep-08	521	7,964	0.0021958	8,159	17	194
Oct-08	457	8,421	0.0021958	8,634	18	213
Nov-08	414	8,835	0.0021958	9,067	19	232
Dec-08	209	9,044	0.0021958	9,296	20	252
TOTAL	9,043.692				252.397	
TOTAL REFUND					$9,296,089	

Separation Of West County Unit 1 Costs

	(A) System ($million)	(B) Jurisdictional Factor	(A) x (B) ($million)
Capital Revenue Requirement	$125.10	98.451%	123.16
Fixed O&M and Capital Replacement	14.30	98.439%	14.08
Variable O&M	1.30	98.439%	1.28
Total Revenue Requirement	$140.70	98.450%	$138.52

Docket No. 080001-EI
R. Deaton, Exhibit No. ______
Document No. RBD-7, Page 1 of 1
Retail Base Revenues For The First 12 Months Of West County Unit 1's Commercial Operation

Customer Class	2009 Jun	2009 Jul	2009 Aug	2009 Sep	2009 Oct	2009 Nov	2009 Dec
Residential	$212,487,514	$235,075,413	$238,446,390	$244,377,143	$202,156,359	$182,614,673	$167,408,836
Commercial	$123,583,765	$127,485,858	$125,636,438	$131,760,475	$115,545,365	$120,515,286	$114,656,278
Industrial	$5,982,916	$6,041,253	$6,085,689	$6,279,752	$6,180,279	$6,024,181	$5,927,361
Street & Highway	$3,717,432	$3,721,901	$3,726,379	$3,730,719	$3,734,976	$3,739,808	$3,745,046
Other	$101,233	$100,997	$100,761	$100,526	$100,292	$100,058	$99,824
Railroads & Railways	$217,868	$222,651	$220,036	$225,470	$222,890	$218,399	$216,382
Total Billed Retail Base Revenue	$346,090,728	$372,648,073	$374,215,693	$386,474,085	$327,940,159	$313,212,405	$292,053,727

Customer Class	2010 Jan	2010 Feb	2010 Mar	2010 April	2010 May	12 Month Ending
Residential	$183,599,158	$155,193,708	$157,364,856	$158,178,006	$181,746,099	$2,318,648,154
Commercial	$110,470,097	$109,312,193	$113,844,495	$112,799,174	$120,502,747	$1,426,112,171
Industrial	$5,907,110	$5,995,233	$6,037,609	$6,209,047	$6,240,149	$72,910,580
Street & Highway	$3,750,806	$3,756,700	$3,762,736	$3,768,494	$3,772,972	$44,927,969
Other	$99,591	$99,359	$99,127	$98,896	$98,665	$1,199,328
Railroads & Railways	$217,025	$208,119	$215,621	$215,861	$212,284	$2,612,606
Total Billed Retail Base Revenue	$304,043,788	$274,565,312	$281,324,445	$281,269,477	$312,572,914	$3,866,410,807

	12 Month Ending
Total Billed Retail Base Revenues From the Sales of Electricity	$3,866,410,807
Unbilled Retail Base Revenues	-$74,140
Total Retail Base Revenues From the Sales of Electricity	$3,866,336,667

Note: Totals may not add due to rounding.

	($million)	source
Jurisdictional Annualized Revenue Requirement	$138.52	Doc. No. RBD-5 as filed
Total Retail Base Revenues From the Sales of Electricity	$3,866.34	Doc. No. RBD-6 as filed
REVISED GBRA FACTOR [(A) / (B)]	3.583%	

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
RS-1	Residential Service			
	Customer Charge/Minimum	$5.33	$5.52	3.6%
	Base Energy Charge (¢ per kWh)			
	First 1,000 kWh	3.398	3.520	3.6%
	All additional kWh	4.429	4.588	3.6%
RST-1	Residential Service -Time of Use			
	Customer Charge/Minimum	$8.46	$8.76	3.5%
	with Lump-sum metering payment	$5.33	$5.52	3.6%
	Base Energy Charge (¢ per kWh)			
	On-Peak	7.130	7.385	3.6%
	Off-Peak	2.189	2.267	3.6%
	Lump-sum payment for time of use metering cost	$150.16	$155.54	3.6%
GS-1	General Service - Non Demand (0-20 kW)			
	Customer Charge/Minimum			
	Metered	$8.50	$8.80	3.5%
	Unmetered	$5.66	$5.86	3.5%
	Base Energy Charge (¢ per kWh)	3.921	4.061	3.6%
GST-1	General Service - Non Demand - Time of Use (0-20 kW)			
	Customer Charge/Minimum	$11.62	$12.04	3.6%
	with Lump-sum metering payment	$8.50	$8.80	3.5%
	Base Energy Charge (¢ per kWh)			
	On-Peak	7.664	7.939	3.6%
	Off-Peak	2.210	2.289	3.6%
	Lump-sum payment for time of use metering cost	$150.16	$155.54	3.6%
GSD-1	General Service Demand (21-499 kW)			
	Customer Charge	$33.05	$34.23	3.6%
	Demand Charge ($/kW)			
	Demand Charge - All kW ($/kW)	$5.09	$5.27	3.5%
	Base Energy Charge (¢ per kWh)	1.39	1.440	3.6%
	Minimum	$139.94	$144.90	3.5%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
GSDT-1	General Service Demand - Time of Use (21-499 kW)			
	Customer Charge	$39.19	$40.59	3.6%
	with Lump-sum metering payment	$33.05	$34.23	3.6%
	Demand Charge - On-Peak ($/kW)	$5.09	$5.27	3.5%
	Base Energy Charge (¢ per kWh)			
	On-Peak	3.244	3.360	3.6%
	Off-Peak	0.892	0.924	3.6%
	Lump-sum payment for time of use metering cost	$365.48	$378.57	3.6%
GSLD-1	General Service Large Demand (500-1999 kW)			
	Customer Charge	$38.72	$40.11	3.6%
	Demand Charge ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)	1.1	1.139	3.5%
	Mimimum	$2,988.72	$3,095.11	3.6%
GSLDT-1	General Service Large Demand - Time of Use (500-1999 kW)			
	Customer Charge	$38.72	$40.11	3.6%
	Demand Charge - On-Peak ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.179	2.257	3.6%
	Off-Peak	0.661	0.685	3.6%
	Mimimum	$2,988.72	$3,095.11	3.6%
CS-1	Curtailable Service (500-1999 kW)			
	Customer Charge.	$103.89	$107.61	3.6%
	Demand Charge ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)	1.101	1.140	3.5%
	Monthly Credit ($ per kW)	($1.61)	($1.67)	3.7%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
CS-1	Curtailable Service (500-1999 kW) (continued)			
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.61	$1.67	3.7%
	Penalty Charge-current month (per kW)	$3.47	$3.59	3.5%
	Early Termination Penalty charge (per kW)	$1.02	$1.06	3.9%
	Minimum	$3,053.89	$3,162.61	3.6%
CST-1	Curtailable Service -Time of Use (500-1999 kW)			
	Customer Charge	$103.89	$107.61	3.6%
	Demand Charge - On-Peak ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.180	2.258	3.6%
	Off-Peak	0.661	0.685	3.6%
	Monthly Credit (per kW)	($1.61)	($1.67)	3.7%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.61	$1.67	3.7%
	Penalty Charge-current month (per kW)	$3.47	$3.59	3.5%
	Early Termination Penalty charge (per kW)	$1.02	$1.06	3.9%
	Minimum	$3,053.89	$3,162.61	3.6%
GSLD-2	General Service Large Demand (2000 kW +)			
	Customer Charge	$160.55	$166.30	3.6%
	Demand Charge ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)	1.097	1.136	3.6%
	Minimum	$11,960.55	$12,386.30	3.6%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
GSLDT-2	General Service Large Demand - Time of Use (2000 kW +)			
	Customer Charge	$160.55	$166.30	3.6%
	Demand Charge - On-Peak ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.288	2.370	3.6%
	Off-Peak	0.619	0.641	3.6%
	Minimum	$11,960.55	$12,386.30	3.6%
CS-2	Curtailable Service (2000 kW +)			
	Customer Charge	$160.55	$166.30	3.6%
	Demand Charge ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)	1.097	1.136	3.6%
	Monthly Credit (per kW)	($1.61)	($1.67)	3.7%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.61	$1.67	3.7%
	Penalty Charge-current month (per kW)	$3.47	$3.59	3.5%
	Early Termination Penalty charge (per kW)	$1.02	$1.06	3.9%
	Minimum	$11,960.55	$12,386.30	3.6%
CST-2	Curtailable Service -Time of Use (2000 kW +)			
	Customer Charge	$160.55	$166.30	3.6%
	Demand Charge - On-Peak ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.292	2.374	3.6%
	Off-Peak	0.619	0.641	3.6%
	Monthly Credit (per kW)	($1.61)	($1.67)	3.7%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.61	$1.67	3.7%
	Penalty Charge-current month (per kW)	$3.47	$3.59	3.5%
	Early Termination Penalty charge (per kW)	$1.02	$1.06	3.9%
	Minimum	$11,960.55	$12,386.30	3.6%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
GSLD-3	General Service Large Demand (2000 kW +)			
	Customer Charge	$377.76	$391.29	3.6%
	Demand Charge ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)	0.57	0.590	3.5%
GSLDT-3	General Service Large Demand - Time of Use (2000 kW +)			
	Customer Charge	$377.76	$391.29	3.6%
	Demand Charge - On-Peak ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)			
	On-Peak	0.634	0.657	3.6%
	Off-Peak	0.508	0.526	3.5%
CS-3	Curtailable Service (2000 kW +)			
	Customer Charge	$377.76	$391.29	3.6%
	Demand Charge ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)	0.570	0.590	3.5%
	Monthly Credit (per kW)	($1.61)	($1.67)	3.7%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.61	$1.67	3.7%
	Penalty Charge-current month (per kW)	$3.47	$3.59	3.5%
	Early Termination Penalty charge (per kW)	$1.02	$1.06	3.9%
CST-3	Curtailable Service -Time of Use (2000 kW +)			
	Customer Charge	$377.76	$391.29	3.6%
	Demand Charge - On-Peak ($/kW)	$5.90	$6.11	3.6%
	Base Energy Charge (¢ per kWh)			
	On-Peak	0.634	0.657	3.6%
	Off-Peak	0.508	0.526	3.5%
	Monthly Credit (per kW)	($1.61)	($1.67)	3.7%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.61	$1.67	3.7%
	Penalty Charge-current month (per kW)	$3.47	$3.59	3.5%
	Early Termination Penalty charge (per kW)	$1.02	$1.06	3.9%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
OS-2	Sports Field Service			
	Customer Charge/Minimum	$8.50	$8.80	3.5%
	Base Energy Charge (¢ per kWh)	5.833	6.042	3.6%
MET	Metropolitan Transit Service			
	Customer Charge	$203.05	$210.32	3.6%
	Base Demand Charge ($/kW)	$9.87	$10.22	3.5%
	Base Energy Charge (¢ per kWh)	0.446	0.462	3.6%
CDR	Commercial/Industrial Demand Reduction Rider			
	Monthly Administrative Adder			
	GSD-1	$533.59	$552.71	3.6%
	GSDT-1	$527.45	$546.35	3.6%
	GSLD-1, GSLDT-1	$527.92	$546.83	3.6%
	GSLD-2, GSLDT-2	$406.09	$420.64	3.6%
	GSLD-3, GSLDT-3	$2,644.34	$2,739.08	3.6%
CILC-1	Commercial/Industrial Load Control Program			
	Customer Charge			
	(G) 200-499kW	$566.64	$586.94	3.6%
	(D) above 500kW	$566.64	$586.94	3.6%
	(T) transmission	$3,022.10	$3,130.37	3.6%
	Base Demand Charge ($/kW)			
	per kW of Max Demand All kW:			
	(G) 200-499kW	$2.24	$2.32	3.6%
	per kW of Max Demand:			
	(D) above 500kW	$2.30	$2.38	3.5%
	(T) transmission	None	None	N/A
	per kW of Load Control On-Peak:			
	(G) 200-499kW	$1.06	$1.10	3.8%
	per kW of Load Control On-Peak:			
	(D) above 500kW	$1.09	$1.13	3.7%
	(T) transmission	$1.08	$1.12	3.7%
	per kW of Firm On-Peak Demand All kW:			
	(G) 200-499kW	$4.53	$4.69	3.5%
	Per kW of Firm On-Peak Demand			
	(D) above 500kW	$5.53	$5.73	3.6%
	(T) transmission	$5.90	$6.11	3.6%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
CILC-1	Commercial/Industrial Load Control Program (continued)			
	Base Energy Charge (¢ per kWh)			
	On-Peak			
	(G) 200-499kW	0.979	1.014	3.6%
	(D) above 500kW	0.681	0.705	3.5%
	(T) transmission	0.502	0.520	3.6%
	Off-Peak			
	(G) 200-499kW	0.979	1.014	3.6%
	(D) above 500kW	0.681	0.705	3.5%
	(T) transmission	0.502	0.520	3.6%
SL-1	Street Lighting			
	Charges for FPL-Owned Units			
	Fixture			
	Sodium Vapor 5,800 lu 70 watts	$3.66	$3.79	3.6%
	Sodium Vapor 9,500 lu 100 watts	$3.73	$3.86	3.5%
	Sodium Vapor 16,000 lu 150 watts	$3.84	$3.98	3.6%
	Sodium Vapor 22,000 lu 200 watts	$5.82	$6.03	3.6%
	Sodium Vapor 50,000 lu 400 watts	$5.89	$6.10	3.6%
	* Sodium Vapor 12,800 lu 150 watts	$4.00	$4.14	3.5%
	* Sodium Vapor 27,500 lu 250 watts	$6.19	$6.41	3.6%
	* Sodium Vapor 140,000 lu 1,000 watts	$9.32	$9.65	3.5%
	* Mercury Vapor 6,000 lu 140 watts	$2.90	$3.00	3.4%
	* Mercury Vapor 8,600 lu 175 watts	$2.93	$3.03	3.4%
	* Mercury Vapor 11,500 lu 250 watts	$4.89	$5.07	3.7%
	* Mercury Vapor 21,500 lu 400 watts	$4.88	$5.05	3.5%
	* Mercury Vapor 39,500 lu 700 watts	$6.89	$7.14	3.6%
	* Mercury Vapor 60,000 lu 1,000 watts	$7.06	$7.31	3.5%
	Maintenance			
	Sodium Vapor 5,800 lu 70 watts	$1.40	$1.45	3.6%
	Sodium Vapor 9,500 lu 100 watts	$1.41	$1.46	3.5%
	Sodium Vapor 16,000 lu 150 watts	$1.44	$1.49	3.5%
	Sodium Vapor 22,000 lu 200 watts	$1.85	$1.92	3.8%
	Sodium Vapor 50,000 lu 400 watts	$1.82	$1.89	3.8%
	* Sodium Vapor 12,800 lu 150 watts	$1.61	$1.67	3.7%
	* Sodium Vapor 27,500 lu 250 watts	$1.96	$2.03	3.6%
	* Sodium Vapor 140,000 lu 1,000 watts	$3.58	$3.71	3.6%
	* Mercury Vapor 6,000 lu 140 watts	$1.27	$1.32	3.9%
	* Mercury Vapor 8,600 lu 175 watts	$1.27	$1.32	3.9%
	* Mercury Vapor 11,500 lu 250 watts	$1.83	$1.90	3.8%
	* Mercury Vapor 21,500 lu 400 watts	$1.80	$1.86	3.3%
	* Mercury Vapor 39,500 lu 700 watts	$3.05	$3.16	3.6%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
	* Mercury Vapor 60,000 lu 1,000 watts	$2.97	$3.08	3.7%
SL-1	Street Lighting (continued)			
	Energy Non-Fuel+			
	Sodium Vapor 5,800 lu 70 watts	$0.61	$0.63	3.3%
	Sodium Vapor 9,500 lu 100 watts	$0.86	$0.89	3.5%
	Sodium Vapor 16,000 lu 150 watts	$1.26	$1.30	3.2%
	Sodium Vapor 22,000 lu 200 watts	$1.84	$1.91	3.8%
	Sodium Vapor 50,000 lu 400 watts	$3.51	$3.64	3.7%
	* Sodium Vapor 12,800 lu 150 watts	$1.26	$1.30	3.2%
	* Sodium Vapor 27,500 lu 250 watts	$2.43	$2.51	3.3%
	* Sodium Vapor 140,000 lu 1,000 watts	$8.60	$8.91	3.6%
	* Mercury Vapor 6,000 lu 140 watts	$1.30	$1.34	3.1%
	* Mercury Vapor 8,600 lu 175 watts	$1.61	$1.67	3.7%
	* Mercury Vapor 11,500 lu 250 watts	$2.18	$2.25	3.2%
	* Mercury Vapor 21,500 lu 400 watts	$3.35	$3.47	3.6%
	* Mercury Vapor 39,500 lu 700 watts	$5.69	$5.89	3.5%
	* Mercury Vapor 60,000 lu 1,000 watts	$8.05	$8.34	3.6%
	Total Charge-Fixtures, Maintenance & Energy			
	* Incandescent 1,000 lu 103 watts	$7.12	$7.38	3.7%
	* Incandescent 2,500 lu 202 watts	$7.37	$7.63	3.5%
	* Incandescent 4,000 lu 327 watts	$8.63	$8.94	3.6%
	* Incandescent 6,000 lu 448 watts	$9.62	$9.96	3.5%
	* Incandescent 10,000 lu 690 watts	$11.58	$11.99	3.5%

* These units are closed to new FPL installations

+ The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the street light unit times the Proposed Non-Fuel Energy Rate
Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)

	Charge for Customer-Owned Units			
	Relamping and Energy			
	Sodium Vapor 5,800 lu 70 watts	$1.32	$1.37	3.8%
	Sodium Vapor 9,500 lu 100 watts	$1.58	$1.64	3.8%
	Sodium Vapor 16,000 lu 150 watts	$1.98	$2.05	3.5%
	Sodium Vapor 22,000 lu 200 watts	$2.57	$2.66	3.5%
	Sodium Vapor 50,000 lu 400 watts	$4.25	$4.40	3.5%
	* Sodium Vapor 12,800 lu 150 watts	$2.22	$2.30	3.6%
	* Sodium Vapor 27,500 lu 250 watts	$3.19	$3.30	3.4%
	* Sodium Vapor 140,000 lu 1,000 watts	$10.29	$10.66	3.6%
	* Mercury Vapor 6,000 lu 140 watts	$2.01	$2.08	3.5%
	* Mercury Vapor 8,600 lu 175 watts	$2.33	$2.41	3.4%
	* Mercury Vapor 11,500 lu 250 watts	$2.94	$3.05	3.7%
	* Mercury Vapor 21,500 lu 400 watts	$4.09	$4.24	3.7%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
	* Mercury Vapor 39,500 lu 700 watts	$7.30	$7.56	3.6%
SL-1	Street Lighting (continued)			
	* Mercury Vapor 60,000 lu 1,000 watts	$9.07	$9.39	3.5%
	* Incandescent 1,000 lu 103 watts	$2.53	$2.62	3.6%
	* Incandescent 2,500 lu 202 watts	$3.26	$3.38	3.7%
	* Incandescent 4,000 lu 327 watts	$4.25	$4.40	3.5%
	* Incandescent 6,000 lu 448 watts	$5.13	$5.31	3.5%
	* Incandescent 10,000 lu 690 watts	$7.06	$7.31	3.5%
	* Fluorescent 19,800 lu 300 watts	$3.49	$3.62	3.7%
	* Fluorescent 39,600 lu 700 watts	$6.74	$6.98	3.6%
	Energy Only+			
	Sodium Vapor 5,800 lu 70 watts	$0.61	$0.63	3.3%
	Sodium Vapor 9,500 lu 100 watts	$0.86	$0.89	3.5%
	Sodium Vapor 16,000 lu 150 watts	$1.26	$1.30	3.2%
	Sodium Vapor 22,000 lu 200 watts	$1.84	$1.91	3.8%
	Sodium Vapor 50,000 lu 400 watts	$3.51	$3.64	3.7%
	* Sodium Vapor 12,800 lu 150 watts	$1.26	$1.30	3.2%
	* Sodium Vapor 27,500 lu 250 watts	$2.43	$2.51	3.3%
	* Sodium Vapor 140,000 lu 1,000 watts	$8.60	$8.91	3.6%
	* Mercury Vapor 6,000 lu 140 watts	$1.30	$1.34	3.1%
	* Mercury Vapor 8,600 lu 175 watts	$1.61	$1.67	3.7%
	* Mercury Vapor 11,500 lu 250 watts	$2.18	$2.25	3.2%
	* Mercury Vapor 21,500 lu 400 watts	$3.35	$3.47	3.6%
	* Mercury Vapor 39,500 lu 700 watts	$5.69	$5.89	3.5%
	* Mercury Vapor 60,000 lu 1,000 watts	$8.05	$8.34	3.6%
	* Incandescent 1,000 lu 103 watts	$0.75	$0.78	4.0%
	* Incandescent 2,500 lu 202 watts	$1.49	$1.54	3.4%
	* Incandescent 4,000 lu 327 watts	$2.42	$2.51	3.7%
	* Incandescent 6,000 lu 448 watts	$3.30	$3.42	3.6%
	* Incandescent 10,000 lu 690 watts	$5.10	$5.28	3.5%
	* Fluorescent 19,800 lu 300 watts	$2.55	$2.64	3.5%
	* Fluorescent 39,600 lu 700 watts	$5.53	$5.73	3.6%
	Non-Fuel Energy (¢ per kWh)	2.092	2.167	3.6%
	Other Charges			
	Wood Pole	$2.62	$2.71	3.4%
	Concrete Pole	$3.60	$3.73	3.6%
	Fiberglass Pole	$4.26	$4.41	3.5%
	Underground conductors not under paving (¢ per foot)	1.97	2.04	3.6%
	Underground conductors under paving (¢ per foot)	4.81	4.98	3.5%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
SL-1	Street Lighting (continued)			

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+ The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the street light unit times the Proposed Non-Fuel Energy Rate
Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
PL-1	Premium Lighting			
	Non-Fuel Energy (¢ per kWh)	2.092	2.167	3.6%
OL-1	Outdoor Lighting			
	Charges for FPL-Owned Units			
	Fixture			
	Sodium Vapor 5,800 lu 70 watts	$4.19	$4.34	3.6%
	Sodium Vapor 9,500 lu 100 watts	$4.30	$4.45	3.5%
	Sodium Vapor 16,000 lu 150 watts	$4.44	$4.60	3.6%
	Sodium Vapor 22,000 lu 200 watts	$6.47	$6.70	3.6%
	Sodium Vapor 50,000 lu 400 watts	$6.88	$7.13	3.6%
	* Sodium Vapor 12,000 lu 150 watts	$4.75	$4.92	3.6%
	* Mercury Vapor 6,000 lu 140 watts	$3.22	$3.34	3.7%
	* Mercury Vapor 8,600 lu 175 watts	$3.24	$3.36	3.7%
	* Mercury Vapor 21,500 lu 400 watts	$5.32	$5.51	3.6%
	Maintenance			
	Sodium Vapor 5,800 lu 70 watts	$1.40	$1.45	3.6%
	Sodium Vapor 9,500 lu 100 watts	$1.41	$1.46	3.5%
	Sodium Vapor 16,000 lu 150 watts	$1.44	$1.49	3.5%
	Sodium Vapor 22,000 lu 200 watts	$1.85	$1.92	3.8%
	Sodium Vapor 50,000 lu 400 watts	$1.82	$1.89	3.8%
	* Sodium Vapor 12,000 lu 150 watts	$1.61	$1.67	3.7%
	* Mercury Vapor 6,000 lu 140 watts	$1.27	$1.32	3.9%
	* Mercury Vapor 8,600 lu 175 watts	$1.27	$1.32	3.9%
	* Mercury Vapor 21,500 lu 400 watts	$1.80	$1.86	3.3%
	Energy Non-Fuel+			
	Sodium Vapor 5,800 lu 70 watts	$0.61	$0.63	3.3%
	Sodium Vapor 9,500 lu 100 watts	$0.86	$0.89	3.5%
	Sodium Vapor 16,000 lu 150 watts	$1.26	$1.30	3.2%
	Sodium Vapor 22,000 lu 200 watts	$1.84	$1.91	3.8%
	Sodium Vapor 50,000 lu 400 watts	$3.52	$3.65	3.7%
	* Sodium Vapor 12,000 lu 150 watts	$1.26	$1.30	3.2%
	* Mercury Vapor 6,000 lu 140 watts	$1.30	$1.35	3.8%
	* Mercury Vapor 8,600 lu 175 watts	$1.61	$1.67	3.7%
	* Mercury Vapor 21,500 lu 400 watts	$3.35	$3.47	3.6%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
OL-1	Outdoor Lighting (continued)			
	Charges for Customer Owned Units			
	Total Charge-Relamping & Energy			
	Sodium Vapor 5,800 lu 70 watts	$1.32	$1.37	3.8%
	Sodium Vapor 9,500 lu 100 watts	$1.59	$1.65	3.8%
	Sodium Vapor 16,000 lu 150 watts	$1.98	$2.05	3.5%
	Sodium Vapor 22,000 lu 200 watts	$2.56	$2.65	3.5%
	Sodium Vapor 50,000 lu 400 watts	$4.25	$4.40	3.5%
	* Sodium Vapor 12,000 lu 150 watts	$2.22	$2.30	3.6%
	* Mercury Vapor 6,000 lu 140 watts	$2.01	$2.08	3.5%
	* Mercury Vapor 8,600 lu 175 watts	$2.33	$2.41	3.4%
	* Mercury Vapor 21,500 lu 400 watts	$4.09	$4.24	3.7%
	Energy Only[+]			
	Sodium Vapor 5,800 lu 70 watts	$0.61	$0.63	3.3%
	Sodium Vapor 9,500 lu 100 watts	$0.86	$0.89	3.5%
	Sodium Vapor 16,000 lu 150 watts	$1.26	$1.30	3.2%
	Sodium Vapor 22,000 lu 200 watts	$1.84	$1.91	3.8%
	Sodium Vapor 50,000 lu 400 watts	$3.52	$3.65	3.7%
	* Sodium Vapor 12,000 lu 150 watts	$1.26	$1.30	3.2%
	* Mercury Vapor 6,000 lu 140 watts	$1.30	$1.35	3.8%
	* Mercury Vapor 8,600 lu 175 watts	$1.61	$1.67	3.7%
	* Mercury Vapor 21,500 lu 400 watts	$3.35	$3.47	3.6%

* These units are closed to new FPL installations

[+] The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the outdoor light unit times the Proposed Non-Fuel Energy Rate
Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)

	Non-Fuel Energy (¢ per kWh)	2.095	2.170	3.6%
	Other Charges			
	Wood Pole	$3.28	$3.40	3.7%
	Concrete Pole	$4.42	$4.58	3.6%
	Fiberglass Pole	$5.19	$5.38	3.7%
	Underground conductors excluding			
	Trenching per foot	$0.015	$0.016	6.7%
	Down-guy, Anchor and Protector	$1.91	$1.98	3.7%
SL-2	Traffic Signal Service			
	Base Energy Charge (¢ per kWh)	3.414	3.536	3.6%
	Minimum charge at each point	$2.69	$2.79	3.7%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
SST-1	Standby and Supplemental Service			
	Customer Charge			
	SST-1(D1)	$127.50	$132.07	3.6%
	SST-1(D2)	$127.50	$132.07	3.6%
	SST-1(D3)	$184.16	$190.76	3.6%
	SST-1(T)	$401.37	$415.75	3.6%
	Distribution Demand $/kW Contract Standby Demand			
	SST-1(D1)	$2.02	$2.09	3.5%
	SST-1(D2)	$2.37	$2.45	3.4%
	SST-1(D3)	$2.08	$2.15	3.4%
	SST-1(T)	N/A	N/A	N/A
	Reservation Demand $/kW			
	SST-1(D1)	$0.75	$0.78	4.0%
	SST-1(D2)	$0.74	$0.77	4.1%
	SST-1(D3)	$0.74	$0.77	4.1%
	SST-1(T)	$0.72	$0.75	4.2%
	Daily Demand (On-Peak) $/kW			
	SST-1(D1)	$0.35	$0.36	2.9%
	SST-1(D2)	$0.34	$0.35	2.9%
	SST-1(D3)	$0.34	$0.35	2.9%
	SST-1(T)	$0.34	$0.35	2.9%
	Non-Fuel Energy - On-Peak (¢ per kWh)			
	SST-1(D1)	0.706	0.731	3.5%
	SST-1(D2)	0.724	0.750	3.6%
	SST-1(D3)	0.716	0.742	3.6%
	SST-1(T)	0.648	0.671	3.5%
	Non-Fuel Energy - Off-Peak (¢ per kWh)			
	SST-1(D1)	0.706	0.731	3.5%
	SST-1(D2)	0.724	0.750	3.6%
	SST-1(D3)	0.716	0.742	3.6%
	SST-1(T)	0.648	0.671	3.5%
ISST-1	Interruptible Standby and Supplemental Service			
	Customer Charge			
	Distribution	$590.25	$611.40	3.6%
	Transmission	$3,045.72	$3,154.84	3.6%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
ISST-1	Interruptible Standby and Supplemental Service (continued)			
	Distribution Demand			
	Distribution	$2.30	$2.38	3.5%
	Transmission	N/A	N/A	N/A
	Reservation Demand-Interruptible			
	Distribution	$0.15	$0.16	6.7%
	Transmission	$0.14	$0.15	7.1%
	Reservation Demand-Firm			
	Distribution	$0.74	$0.77	4.1%
	Transmission	$0.72	$0.75	4.2%
	Daily Demand (On-Peak) Firm Standby			
	Distribution	$0.34	$0.35	2.9%
	Transmission	$0.34	$0.35	2.9%
	Daily Demand (On-Peak) Interruptible Standby			
	Distribution	$0.07	$0.07	0.0%
	Transmission	$0.07	$0.07	0.0%
	Non-Fuel Energy - On-Peak (¢ per kWh)			
	Distribution	0.713	0.739	3.6%
	Transmission	0.502	0.520	3.6%
	Non-Fuel Energy - Off-Peak (¢ per kWh)			
	Distribution	0.713	0.739	3.6%
	Transmission	0.502	0.520	3.6%
WIES-1	Wireless Internet Electric Service			
	Non-Fuel Energy (¢ per kWh)	18.087	18.735	3.6%
TR	Transformation Rider			
	Transformer Credit			
	(per kW of Billing Demand)	($0.37)	($0.38)	2.7%
GSCU-1	GENERAL SERVICE CONSTANT USAGE			
	Customer Charge:	$9.43	$9.77	3.6%
	Non-Fuel Energy Charges:			
	Base Energy Charge (¢ per kWh)*	2.445	2.533	3.6%

* The non-fuel energy charges will be assessed on the Constant Usage kWh

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
HLFT-1	HIGH LOAD FACTOR – TIME OF USE			
	Customer Charge:			
	For customers with an Annual Maximum Demand less than 500 kW:	$39.19	$40.59	3.6%
	For customers with an Annual Maximum Demand less than 2000 kW:	$38.72	$40.11	3.6%
	For customers with an Annual Maximum Demand of 2000 kW or more:	$160.55	$166.30	3.6%
	Demand Charges:			
	On-peak Demand Charge:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$7.02	$7.27	3.6%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$7.01	$7.26	3.6%
	For customers with an Annual Maximum Demand 2000+ kW:	$7.01	$7.26	3.6%
	Maximum Demand Charge:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$1.50	$1.55	3.3%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$1.54	$1.60	3.9%
	For customers with an Annual Maximum Demand 2000+ kW:	$1.52	$1.57	3.3%
	Non-Fuel Energy Charges: (¢ per kWh)			
	Base Energy Charge (¢ per kWh):			
	On-Peak Period			
	For customers with an Annual Maximum Demand 21 - 499 kW:	1.588	1.645	3.6%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.499	0.517	3.6%
	For customers with an Annual Maximum Demand 2000+ kW:	0.499	0.517	3.6%
	Off-Peak Period			
	For customers with an Annual Maximum Demand 21 - 499 kW:	0.499	0.517	3.6%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.499	0.517	3.6%
	For customers with an Annual Maximum Demand 2000+ kW:	0.499	0.517	3.6%
SDTR	SEASONAL DEMAND -TIME OF USE RIDER			
	Customer Charge:			
	For customers with an Annual Maximum Demand less than 500 kW:			
	Otherwise applicable Rate Schedule GSD-1	$33.05	$34.23	3.6%
	Otherwise applicable Rate Schedule GSDT-1	$39.19	$40.59	3.6%
	For customers with an Annual Maximum Demand less than 2000 kW:	$38.72	$40.11	3.6%
	For customers with an Annual Maximum Demand of 2000 kW or more:	$160.55	$166.30	3.6%
	Demand and Energy Charges during June through September (SEASONAL):			
	Demand Charges:			
	Seasonal On-Peak Demand Charge per kW of Seasonal On-Peak Demand:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$5.69	$5.89	3.5%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$6.28	$6.50	3.5%
	For customers with an Annual Maximum Demand 2000+ kW:	$6.28	$6.50	3.5%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE AS OF 1/1/09	(4) PROPOSED RATE With GBRA WCEC 1	(5) PERCENT INCREASE [((4) - (3)) / (3)]
SDTR	SEASONAL DEMAND -TIME OF USE RIDER (continued)			
	Non-Fuel Energy Charges (¢ per kWh):			
	Base Seasonal Off-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	1.060	1.098	3.6%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.839	0.869	3.6%
	For customers with an Annual Maximum Demand 2000+ kW:	0.836	0.866	3.6%
	Base Seasonal On-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	4.012	4.156	3.6%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	3.071	3.181	3.6%
	For customers with an Annual Maximum Demand 2000+ kW:	3.063	3.173	3.6%
	OPTION A: Non-Seasonal Standard Rate			
	Demand Charges:			
	Non-Seasonal Demand Charge per kW of Non-Seasonal Maximum Demand:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$4.79	$4.96	3.5%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$5.70	$5.90	3.5%
	For customers with an Annual Maximum Demand 2000+ kW:	$5.70	$5.90	3.5%
	Non-Fuel Energy Charges: (¢ per Non-Seasonal kWh)			
	Non-Seasonal Energy Charge:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	1.390	1.440	3.6%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	1.1	1.139	3.5%
	For customers with an Annual Maximum Demand 2000+ kW:	1.097	1.136	3.6%
	OR			
	OPTION B: Non-Seasonal Time of Use Rate			
	Demand Charges per kW of Non-Seasonal Demand occurring during the Non-Seasonal On-Peak period:			
	Non-Seasonal Demand Charge :			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$4.79	$4.96	3.5%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$5.70	$5.90	3.5%
	For customers with an Annual Maximum Demand 2000+ kW:	$5.70	$5.90	3.5%
	OPTION B: Non-Seasonal Time of Use Rate			
	Non-Fuel Energy Charges: (¢ per kWh)			
	Non-Seasonal On-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	3.244	3.360	3.6%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	2.179	2.257	3.6%
	For customers with an Annual Maximum Demand 2000+ kW:	2.288	2.370	3.6%
	Non-Seasonal Off-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	0.892	0.924	3.6%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.661	0.685	3.6%
	For customers with an Annual Maximum Demand 2000+ kW:	0.619	0.641	3.6%

Separation Of West County Unit 2 Costs

	(A) System ($million)	(B) Jurisdictional Factor	(A) x (B) ($million)
Capital Revenue Requirement	$115.10	98.451%	113.32
Fixed O&M and Capital Replacement	12.70	98.439%	12.50
Variable O&M	1.30	98.439%	1.28
Total Revenue Requirement	$129.10	98.450%	$127.10

Docket No. 080001-EI
R. Deaton, Exhibit No. ______
Document No. RBD-11, Page 1 of 1
Retail Base Revenues For The First 12 Months Of West County Unit 2's Commercial Operation

Customer Class	2009 Nov	2009 Dec	2010 Jan	2010 Feb	2010 Mar	2010 Apr	2010 May
Residential	$189,157,756	$173,407,095	$190,177,516	$160,754,299	$163,003,238	$163,845,524	$188,258,061
Commercial	$124,728,886	$118,664,669	$114,333,067	$113,138,102	$117,823,773	$116,736,045	$124,712,365
Industrial	$6,225,276	$6,123,589	$6,104,776	$6,192,035	$6,239,371	$6,413,692	$6,446,427
Street & Highway	$3,873,806	$3,879,231	$3,885,198	$3,891,302	$3,897,555	$3,903,520	$3,908,157
Other	$103,643	$103,401	$103,159	$102,919	$102,679	$102,439	$102,200
Railroads & Railways	$226,224	$224,135	$224,801	$215,576	$223,347	$223,595	$219,890
Total Billed Retail Base Revenue	$324,315,590	$302,402,119	$314,828,517	$284,294,233	$291,289,963	$291,224,815	$323,647,100

Customer Class	2010 Jun	2010 Jul	2010 Aug	2010 Sep	2010 Oct	12 Month Ending
Residential	$221,189,318	$244,603,163	$248,412,611	$255,184,475	$211,181,327	$2,409,174,383
Commercial	$131,324,065	$135,402,754	$133,395,897	$139,907,540	$122,950,435	$1,493,117,598
Industrial	$6,344,917	$6,399,537	$6,432,412	$6,609,756	$6,502,380	$76,034,167
Street & Highway	$3,912,364	$3,916,471	$3,920,704	$3,924,908	$3,929,136	$46,842,352
Other	$101,961	$101,724	$101,486	$101,249	$101,013	$1,227,873
Railroads & Railways	$225,674	$230,629	$227,920	$233,549	$230,876	$2,706,215
Total Billed Retail Base Revenue	$363,098,299	$390,654,276	$392,491,031	$405,961,477	$344,895,167	$4,029,102,588

	12 Month Ending
Total Billed Retail Base Revenues From the Sales of Electricity	$4,029,102,588
Unbilled Retail Base Revenues	$1,198,239
Total Retail Base Revenues From the Sales of Electricity	$4,030,300,827

Note: Totals may not add due to rounding.

	($million)	source
Jurisdictional Annualized Revenue Requirement	$127.10	Doc. No. RBD-9 as filed
Total Retail Base Revenues From the Sales of Electricity	$4,030.30	Doc. No. RBD-10 as filed
REVISED GBRA FACTOR [(A) / (B)]	3.154%	

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
RS-1	Residential Service			
	Customer Charge/Minimum	$5.52	$5.69	3.1%
	Base Energy Charge (¢ per kWh)			
	First 1,000 kWh	3.520	3.631	3.2%
	All additional kWh	4.588	4.733	3.2%
RST-1	Residential Service -Time of Use			
	Customer Charge/Minimum	$8.76	$9.04	3.2%
	with Lump-sum metering payment	$5.52	$5.69	3.1%
	Base Energy Charge (¢ per kWh)			
	On-Peak	7.385	7.618	3.2%
	Off-Peak	2.267	2.338	3.1%
	Lump-sum payment for time of use metering cost	$155.54	$160.45	3.2%
GS-1	General Service - Non Demand (0-20 kW)			
	Customer Charge/Minimum			
	Metered	$8.80	$9.08	3.2%
	Unmetered	$5.86	$6.04	3.1%
	Base Energy Charge (¢ per kWh)	4.061	4.189	3.2%
GST-1	General Service - Non Demand - Time of Use (0-20 kW)			
	Customer Charge/Minimum	$12.04	$12.42	3.2%
	with Lump-sum metering payment	$8.80	$9.08	3.2%
	Base Energy Charge (¢ per kWh)			
	On-Peak	7.939	8.189	3.1%
	Off-Peak	2.289	2.361	3.1%
	Lump-sum payment for time of use metering cost	$155.54	$160.45	3.2%
GSD-1	General Service Demand (21-499 kW)			
	Customer Charge	$34.23	$35.31	3.2%
	Demand Charge ($/kW)			
	Demand Charge - All kW ($/kW)	$5.27	$5.44	3.2%
	Base Energy Charge (¢ per kWh)	1.44	1.485	3.1%
	Minimum	$144.90	$149.55	3.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
GSDT-1	General Service Demand - Time of Use (21-499 kW)			
	Customer Charge	$40.59	$41.87	3.2%
	with Lump-sum metering payment	$34.23	$35.31	3.2%
	Demand Charge - On-Peak ($/kW)	$5.27	$5.44	3.2%
	Base Energy Charge (¢ per kWh)			
	On-Peak	3.360	3.466	3.2%
	Off-Peak	0.924	0.953	3.1%
	Lump-sum payment for time of use metering cost	$378.57	$390.51	3.2%
GSLD-1	General Service Large Demand (500-1999 kW)			
	Customer Charge	$40.11	$41.37	3.1%
	Demand Charge ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)	1.139	1.175	3.2%
	Mimimum	$3,095.11	$3,191.37	3.1%
GSLDT-1	General Service Large Demand - Time of Use (500-1999 kW)			
	Customer Charge	$40.11	$41.37	3.1%
	Demand Charge - On-Peak ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.257	2.328	3.1%
	Off-Peak	0.685	0.707	3.2%
	Mimimum	$3,095.11	$3,191.37	3.1%
CS-1	Curtailable Service (500-1999 kW)			
	Customer Charge	$107.61	$111.00	3.2%
	Demand Charge ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)	1.14	1.176	3.2%
	Monthly Credit ($ per kW)	($1.67)	($1.72)	3.0%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
CS-1	Curtailable Service (500-1999 kW) (continued)			
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.67	$1.72	3.0%
	Penalty Charge-current month (per kW)	$3.59	$3.70	3.1%
	Early Termination Penalty charge (per kW)	$1.06	$1.09	2.8%
	Minimum	$3,162.61	$3,261.00	3.1%
CST-1	Curtailable Service -Time of Use (500-1999 kW)			
	Customer Charge	$107.61	$111.00	3.2%
	Demand Charge - On-Peak ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.258	2.329	3.1%
	Off-Peak	0.685	0.707	3.2%
	Monthly Credit (per kW)	($1.67)	($1.72)	3.0%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.67	$1.72	3.0%
	Penalty Charge-current month (per kW)	$3.59	$3.70	3.1%
	Early Termination Penalty charge (per kW)	$1.06	$1.09	2.8%
	Minimum	$3,162.61	$3,261.00	3.1%
GSLD-2	General Service Large Demand (2000 kW +)			
	Customer Charge	$166.30	$171.54	3.2%
	Demand Charge ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)	1.136	1.172	3.2%
	Minimum	$12,386.30	$12,771.54	3.1%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
GSLDT-2	General Service Large Demand - Time of Use (2000 kW +)			
	Customer Charge	$166.30	$171.54	3.2%
	Demand Charge - On-Peak ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.370	2.445	3.2%
	Off-Peak	0.641	0.661	3.1%
	Minimum	$12,386.30	$12,771.54	3.1%
CS-2	Curtailable Service (2000 kW +)			
	Customer Charge	$166.30	$171.54	3.2%
	Demand Charge ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)	1.136	1.172	3.2%
	Monthly Credit (per kW)	($1.67)	($1.72)	3.0%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.67	$1.72	3.0%
	Penalty Charge-current month (per kW)	$3.59	$3.70	3.1%
	Early Termination Penalty charge (per kW)	$1.06	$1.09	2.8%
	Minimum	$12,386.30	$12,771.54	3.1%
CST-2	Curtailable Service -Time of Use (2000 kW +)			
	Customer Charge	$166.30	$171.54	3.2%
	Demand Charge - On-Peak ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.374	2.449	3.2%
	Off-Peak	0.641	0.661	3.1%
	Monthly Credit (per kW)	($1.67)	($1.72)	3.0%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.67	$1.72	3.0%
	Penalty Charge-current month (per kW)	$3.59	$3.70	3.1%
	Early Termination Penalty charge (per kW)	$1.06	$1.09	2.8%
	Minimum	$12,386.30	$12,771.54	3.1%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
GSLD-3	General Service Large Demand (2000 kW +)			
	Customer Charge	$391.29	$403.63	3.2%
	Demand Charge ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)	0.59	0.609	3.2%
GSLDT-3	General Service Large Demand - Time of Use (2000 kW +)			
	Customer Charge	$391.29	$403.63	3.2%
	Demand Charge - On-Peak ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)			
	On-Peak	0.657	0.678	3.2%
	Off-Peak	0.526	0.543	3.2%
CS-3	Curtailable Service (2000 kW +)			
	Customer Charge	$391.29	$403.63	3.2%
	Demand Charge ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)	0.590	0.609	3.2%
	Monthly Credit (per kW)	($1.67)	($1.72)	3.0%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.67	$1.72	3.0%
	Penalty Charge-current month (per kW)	$3.59	$3.70	3.1%
	Early Termination Penalty charge (per kW)	$1.06	$1.09	2.8%
CST-3	Curtailable Service -Time of Use (2000 kW +)			
	Customer Charge	$391.29	$403.63	3.2%
	Demand Charge - On-Peak ($/kW)	$6.11	$6.30	3.1%
	Base Energy Charge (¢ per kWh)			
	On-Peak	0.657	0.678	3.2%
	Off-Peak	0.526	0.543	3.2%
	Monthly Credit (per kW)	($1.67)	($1.72)	3.0%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.67	$1.72	3.0%
	Penalty Charge-current month (per kW)	$3.59	$3.70	3.1%
	Early Termination Penalty charge (per kW)	$1.06	$1.09	2.8%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
OS-2	Sports Field Service			
	Customer Charge/Minimum	$8.80	$9.08	3.2%
	Base Energy Charge (¢ per kWh)	6.042	6.233	3.2%
MET	Metropolitan Transit Service			
	Customer Charge	$210.32	$216.95	3.2%
	Base Demand Charge ($/kW)	$10.22	$10.54	3.1%
	Base Energy Charge (¢ per kWh)	0.462	0.477	3.2%
CDR	Commercial/Industrial Demand Reduction Rider			
	Monthly Administrative Adder			
	GSD-1	$552.71	$570.14	3.2%
	GSDT-1	$546.35	$563.58	3.2%
	GSLD-1, GSLDT-1	$546.83	$564.07	3.2%
	GSLD-2, GSLDT-2	$420.64	$433.91	3.2%
	GSLD-3, GSLDT-3	$2,739.08	$2,825.46	3.2%
CILC-1	Commercial/Industrial Load Control Program			
	Customer Charge			
	(G) 200-499kW	$586.94	$605.45	3.2%
	(D) above 500kW	$586.94	$605.45	3.2%
	(T) transmission	$3,130.37	$3,229.09	3.2%
	Base Demand Charge ($/kW)			
	per kW of Max Demand All kW:			
	(G) 200-499kW	$2.32	$2.39	3.0%
	per kW of Max Demand:			
	(D) above 500kW	$2.38	$2.46	3.4%
	(T) transmission	None	None	N/A
	per kW of Load Control On-Peak:			
	(G) 200-499kW	$1.10	$1.13	2.7%
	per kW of Load Control On-Peak:			
	(D) above 500kW	$1.13	$1.17	3.5%
	(T) transmission	$1.12	$1.16	3.6%
	per kW of Firm On-Peak Demand All kW:			
	(G) 200-499kW	$4.69	$4.84	3.2%
	Per kW of Firm On-Peak Demand			
	(D) above 500kW	$5.73	$5.91	3.1%
	(T) transmission	$6.11	$6.30	3.1%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
CILC-1	Commercial/Industrial Load Control Program (continued)			
	Base Energy Charge (¢ per kWh)			
	On-Peak			
	(G) 200-499kW	1.014	1.046	3.2%
	(D) above 500kW	0.705	0.727	3.1%
	(T) transmission	0.520	0.536	3.1%
	Off-Peak			
	(G) 200-499kW	1.014	1.046	3.2%
	(D) above 500kW	0.705	0.727	3.1%
	(T) transmission	0.520	0.536	3.1%
SL-1	Street Lighting			
	Charges for FPL-Owned Units			
	Fixture			
	Sodium Vapor 5,800 lu 70 watts	$3.79	$3.91	3.2%
	Sodium Vapor 9,500 lu 100 watts	$3.86	$3.98	3.1%
	Sodium Vapor 16,000 lu 150 watts	$3.98	$4.11	3.3%
	Sodium Vapor 22,000 lu 200 watts	$6.03	$6.22	3.2%
	Sodium Vapor 50,000 lu 400 watts	$6.10	$6.29	3.1%
	* Sodium Vapor 12,800 lu 150 watts	$4.14	$4.27	3.1%
	* Sodium Vapor 27,500 lu 250 watts	$6.41	$6.61	3.1%
	* Sodium Vapor 140,000 lu 1,000 watts	$9.65	$9.95	3.1%
	* Mercury Vapor 6,000 lu 140 watts	$3.00	$3.09	3.0%
	* Mercury Vapor 8,600 lu 175 watts	$3.03	$3.13	3.3%
	* Mercury Vapor 11,500 lu 250 watts	$5.07	$5.23	3.2%
	* Mercury Vapor 21,500 lu 400 watts	$5.05	$5.21	3.2%
	* Mercury Vapor 39,500 lu 700 watts	$7.14	$7.37	3.2%
	* Mercury Vapor 60,000 lu 1,000 watts	$7.31	$7.54	3.1%
	Maintenance			
	Sodium Vapor 5,800 lu 70 watts	$1.45	$1.50	3.4%
	Sodium Vapor 9,500 lu 100 watts	$1.46	$1.51	3.4%
	Sodium Vapor 16,000 lu 150 watts	$1.49	$1.54	3.4%
	Sodium Vapor 22,000 lu 200 watts	$1.92	$1.98	3.1%
	Sodium Vapor 50,000 lu 400 watts	$1.89	$1.95	3.2%
	* Sodium Vapor 12,800 lu 150 watts	$1.67	$1.72	3.0%
	* Sodium Vapor 27,500 lu 250 watts	$2.03	$2.09	3.0%
	* Sodium Vapor 140,000 lu 1,000 watts	$3.71	$3.83	3.2%
	* Mercury Vapor 6,000 lu 140 watts	$1.32	$1.36	3.0%
	* Mercury Vapor 8,600 lu 175 watts	$1.32	$1.36	3.0%
	* Mercury Vapor 11,500 lu 250 watts	$1.90	$1.96	3.2%
	* Mercury Vapor 21,500 lu 400 watts	$1.86	$1.92	3.2%
	* Mercury Vapor 39,500 lu 700 watts	$3.16	$3.26	3.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
	* Mercury Vapor 60,000 lu 1,000 watts	$3.08	$3.18	3.2%
SL-1	Street Lighting (continued)			
	Energy Non-Fuel+			
	Sodium Vapor 5,800 lu 70 watts	$0.63	$0.65	3.2%
	Sodium Vapor 9,500 lu 100 watts	$0.89	$0.92	3.4%
	Sodium Vapor 16,000 lu 150 watts	$1.30	$1.34	3.1%
	Sodium Vapor 22,000 lu 200 watts	$1.91	$1.97	3.1%
	Sodium Vapor 50,000 lu 400 watts	$3.64	$3.75	3.0%
	* Sodium Vapor 12,800 lu 150 watts	$1.30	$1.34	3.1%
	* Sodium Vapor 27,500 lu 250 watts	$2.51	$2.59	3.2%
	* Sodium Vapor 140,000 lu 1,000 watts	$8.91	$9.19	3.1%
	* Mercury Vapor 6,000 lu 140 watts	$1.34	$1.39	3.7%
	* Mercury Vapor 8,600 lu 175 watts	$1.67	$1.72	3.0%
	* Mercury Vapor 11,500 lu 250 watts	$2.25	$2.32	3.1%
	* Mercury Vapor 21,500 lu 400 watts	$3.47	$3.58	3.2%
	* Mercury Vapor 39,500 lu 700 watts	$5.89	$6.08	3.2%
	* Mercury Vapor 60,000 lu 1,000 watts	$8.34	$8.60	3.1%
	Total Charge-Fixtures, Maintenance & Energy			
	* Incandescent 1,000 lu 103 watts	$7.38	$7.61	3.1%
	* Incandescent 2,500 lu 202 watts	$7.63	$7.87	3.1%
	* Incandescent 4,000 lu 327 watts	$8.94	$9.22	3.1%
	* Incandescent 6,000 lu 448 watts	$9.96	$10.27	3.1%
	* Incandescent 10,000 lu 690 watts	$11.99	$12.37	3.2%

* These units are closed to new FPL installations

+ The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the street light unit times the Proposed Non-Fuel Energy Rate
Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)

	<u>Charge for Customer-Owned Units</u>			
	Relamping and Energy			
	Sodium Vapor 5,800 lu 70 watts	$1.37	$1.41	2.9%
	Sodium Vapor 9,500 lu 100 watts	$1.64	$1.69	3.0%
	Sodium Vapor 16,000 lu 150 watts	$2.05	$2.11	2.9%
	Sodium Vapor 22,000 lu 200 watts	$2.66	$2.74	3.0%
	Sodium Vapor 50,000 lu 400 watts	$4.40	$4.54	3.2%
	* Sodium Vapor 12,800 lu 150 watts	$2.30	$2.37	3.0%
	* Sodium Vapor 27,500 lu 250 watts	$3.30	$3.40	3.0%
	* Sodium Vapor 140,000 lu 1,000 watts	$10.66	$11.00	3.2%
	* Mercury Vapor 6,000 lu 140 watts	$2.08	$2.15	3.4%
	* Mercury Vapor 8,600 lu 175 watts	$2.41	$2.49	3.3%
	* Mercury Vapor 11,500 lu 250 watts	$3.05	$3.15	3.3%
	* Mercury Vapor 21,500 lu 400 watts	$4.24	$4.37	3.1%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
	* Mercury Vapor 39,500 lu 700 watts	$7.56	$7.80	3.2%
SL-1	Street Lighting (continued)			
	* Mercury Vapor 60,000 lu 1,000 watts	$9.39	$9.69	3.2%
	* Incandescent 1,000 lu 103 watts	$2.62	$2.70	3.1%
	* Incandescent 2,500 lu 202 watts	$3.38	$3.49	3.3%
	* Incandescent 4,000 lu 327 watts	$4.40	$4.54	3.2%
	* Incandescent 6,000 lu 448 watts	$5.31	$5.48	3.2%
	* Incandescent 10,000 lu 690 watts	$7.31	$7.54	3.1%
	* Fluorescent 19,800 lu 300 watts	$3.62	$3.73	3.0%
	* Fluorescent 39,600 lu 700 watts	$6.98	$7.20	3.2%
	Energy Only[+]			
	Sodium Vapor 5,800 lu 70 watts	$0.63	$0.65	3.2%
	Sodium Vapor 9,500 lu 100 watts	$0.89	$0.92	3.4%
	Sodium Vapor 16,000 lu 150 watts	$1.30	$1.34	3.1%
	Sodium Vapor 22,000 lu 200 watts	$1.91	$1.97	3.1%
	Sodium Vapor 50,000 lu 400 watts	$3.64	$3.75	3.0%
	* Sodium Vapor 12,800 lu 150 watts	$1.30	$1.34	3.1%
	* Sodium Vapor 27,500 lu 250 watts	$2.51	$2.59	3.2%
	* Sodium Vapor 140,000 lu 1,000 watts	$8.91	$9.19	3.1%
	* Mercury Vapor 6,000 lu 140 watts	$1.34	$1.39	3.7%
	* Mercury Vapor 8,600 lu 175 watts	$1.67	$1.72	3.0%
	* Mercury Vapor 11,500 lu 250 watts	$2.25	$2.32	3.1%
	* Mercury Vapor 21,500 lu 400 watts	$3.47	$3.58	3.2%
	* Mercury Vapor 39,500 lu 700 watts	$5.89	$6.08	3.2%
	* Mercury Vapor 60,000 lu 1,000 watts	$8.34	$8.60	3.1%
	* Incandescent 1,000 lu 103 watts	$0.78	$0.80	2.6%
	* Incandescent 2,500 lu 202 watts	$1.54	$1.59	3.2%
	* Incandescent 4,000 lu 327 watts	$2.51	$2.59	3.2%
	* Incandescent 6,000 lu 448 watts	$3.42	$3.53	3.2%
	* Incandescent 10,000 lu 690 watts	$5.28	$5.45	3.2%
	* Fluorescent 19,800 lu 300 watts	$2.64	$2.72	3.0%
	* Fluorescent 39,600 lu 700 watts	$5.73	$5.91	3.1%
	Non-Fuel Energy (¢ per kWh)	2.167	2.235	3.1%
	<u>Other Charges</u>			
	Wood Pole	$2.71	$2.80	3.3%
	Concrete Pole	$3.73	$3.85	3.2%
	Fiberglass Pole	$4.41	$4.55	3.2%
	Underground conductors not under paving (¢ per foot)	2.04	2.10	2.9%
	Underground conductors under paving (¢ per foot)	4.98	5.14	3.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
SL-1	Street Lighting (continued)			

* These units are closed to new FPL installations

+ The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the street light unit times the Proposed Non-Fuel Energy Rate
Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
PL-1	Premium Lighting			
	Non-Fuel Energy (¢ per kWh)	2.167	2.235	3.1%
OL-1	Outdoor Lighting			
	Charges for FPL-Owned Units			
	Fixture			
	Sodium Vapor 5,800 lu 70 watts	$4.34	$4.48	3.2%
	Sodium Vapor 9,500 lu 100 watts	$4.45	$4.59	3.1%
	Sodium Vapor 16,000 lu 150 watts	$4.60	$4.75	3.3%
	Sodium Vapor 22,000 lu 200 watts	$6.70	$6.91	3.1%
	Sodium Vapor 50,000 lu 400 watts	$7.13	$7.35	3.1%
	* Sodium Vapor 12,000 lu 150 watts	$4.92	$5.08	3.3%
	* Mercury Vapor 6,000 lu 140 watts	$3.34	$3.45	3.3%
	* Mercury Vapor 8,600 lu 175 watts	$3.36	$3.47	3.3%
	* Mercury Vapor 21,500 lu 400 watts	$5.51	$5.68	3.1%
	Maintenance			
	Sodium Vapor 5,800 lu 70 watts	$1.45	$1.50	3.4%
	Sodium Vapor 9,500 lu 100 watts	$1.46	$1.51	3.4%
	Sodium Vapor 16,000 lu 150 watts	$1.49	$1.54	3.4%
	Sodium Vapor 22,000 lu 200 watts	$1.92	$1.98	3.1%
	Sodium Vapor 50,000 lu 400 watts	$1.89	$1.95	3.2%
	* Sodium Vapor 12,000 lu 150 watts	$1.67	$1.72	3.0%
	* Mercury Vapor 6,000 lu 140 watts	$1.32	$1.36	3.0%
	* Mercury Vapor 8,600 lu 175 watts	$1.32	$1.36	3.0%
	* Mercury Vapor 21,500 lu 400 watts	$1.86	$1.92	3.2%
	Energy Non-Fuel+			
	Sodium Vapor 5,800 lu 70 watts	$0.63	$0.65	3.2%
	Sodium Vapor 9,500 lu 100 watts	$0.89	$0.92	3.4%
	Sodium Vapor 16,000 lu 150 watts	$1.30	$1.34	3.1%
	Sodium Vapor 22,000 lu 200 watts	$1.91	$1.97	3.1%
	Sodium Vapor 50,000 lu 400 watts	$3.65	$3.76	3.0%
	* Sodium Vapor 12,000 lu 150 watts	$1.30	$1.34	3.1%
	* Mercury Vapor 6,000 lu 140 watts	$1.35	$1.39	3.0%
	* Mercury Vapor 8,600 lu 175 watts	$1.67	$1.72	3.0%
	* Mercury Vapor 21,500 lu 400 watts	$3.47	$3.58	3.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
OL-1	Outdoor Lighting (continued)			
	Charges for Customer Owned Units			
	Total Charge-Relamping & Energy			
	Sodium Vapor 5,800 lu 70 watts	$1.37	$1.41	2.9%
	Sodium Vapor 9,500 lu 100 watts	$1.65	$1.70	3.0%
	Sodium Vapor 16,000 lu 150 watts	$2.05	$2.11	2.9%
	Sodium Vapor 22,000 lu 200 watts	$2.65	$2.73	3.0%
	Sodium Vapor 50,000 lu 400 watts	$4.40	$4.54	3.2%
	* Sodium Vapor 12,000 lu 150 watts	$2.30	$2.37	3.0%
	* Mercury Vapor 6,000 lu 140 watts	$2.08	$2.15	3.4%
	* Mercury Vapor 8,600 lu 175 watts	$2.41	$2.49	3.3%
	* Mercury Vapor 21,500 lu 400 watts	$4.24	$4.37	3.1%
	Energy Only+			
	Sodium Vapor 5,800 lu 70 watts	$0.63	$0.65	3.2%
	Sodium Vapor 9,500 lu 100 watts	$0.89	$0.92	3.4%
	Sodium Vapor 16,000 lu 150 watts	$1.30	$1.34	3.1%
	Sodium Vapor 22,000 lu 200 watts	$1.91	$1.97	3.1%
	Sodium Vapor 50,000 lu 400 watts	$3.65	$3.76	3.0%
	* Sodium Vapor 12,000 lu 150 watts	$1.30	$1.34	3.1%
	* Mercury Vapor 6,000 lu 140 watts	$1.35	$1.39	3.0%
	* Mercury Vapor 8,600 lu 175 watts	$1.67	$1.72	3.0%
	* Mercury Vapor 21,500 lu 400 watts	$3.47	$3.58	3.2%

* These units are closed to new FPL installations

+ The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the outdoor light unit times the Proposed Non-Fuel Energy Rate
Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)

	Non-Fuel Energy (¢ per kWh)	2.170	2.238	3.1%
	Other Charges			
	Wood Pole	$3.40	$3.51	3.2%
	Concrete Pole	$4.58	$4.72	3.1%
	Fiberglass Pole	$5.38	$5.55	3.2%
	Underground conductors excluding			
	Trenching per foot	$0.016	$0.017	6.3%
	Down-guy, Anchor and Protector	$1.98	$2.04	3.0%
SL-2	Traffic Signal Service			
	Base Energy Charge (¢ per kWh)	3.536	3.648	3.2%
	Minimum charge at each point	$2.79	$2.88	3.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
SST-1	Standby and Supplemental Service			
	Customer Charge			
	SST-1(D1)	$132.07	$136.23	3.1%
	SST-1(D2)	$132.07	$136.23	3.1%
	SST-1(D3)	$190.76	$196.78	3.2%
	SST-1(T)	$415.75	$428.86	3.2%
	Distribution Demand $/kW Contract Standby Demand			
	SST-1(D1)	$2.09	$2.16	3.3%
	SST-1(D2)	$2.45	$2.53	3.3%
	SST-1(D3)	$2.15	$2.22	3.3%
	SST-1(T)	N/A	N/A	N/A
	Reservation Demand $/kW			
	SST-1(D1)	$0.78	$0.80	2.6%
	SST-1(D2)	$0.77	$0.79	2.6%
	SST-1(D3)	$0.77	$0.79	2.6%
	SST-1(T)	$0.75	$0.77	2.7%
	Daily Demand (On-Peak) $/kW			
	SST-1(D1)	$0.36	$0.37	2.8%
	SST-1(D2)	$0.35	$0.36	2.9%
	SST-1(D3)	$0.35	$0.36	2.9%
	SST-1(T)	$0.35	$0.36	2.9%
	Non-Fuel Energy - On-Peak (¢ per kWh)			
	SST-1(D1)	0.731	0.754	3.1%
	SST-1(D2)	0.750	0.774	3.2%
	SST-1(D3)	0.742	0.765	3.1%
	SST-1(T)	0.671	0.692	3.1%
	Non-Fuel Energy - Off-Peak (¢ per kWh)			
	SST-1(D1)	0.731	0.754	3.1%
	SST-1(D2)	0.750	0.774	3.2%
	SST-1(D3)	0.742	0.765	3.1%
	SST-1(T)	0.671	0.692	3.1%
ISST-1	Interruptible Standby and Supplemental Service			
	Customer Charge			
	Distribution	$611.40	$630.68	3.2%
	Transmission	$3,154.84	$3,254.33	3.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
ISST-1	Interruptible Standby and Supplemental Service (continued)			
	Distribution Demand			
	Distribution	$2.38	$2.46	3.4%
	Transmission	N/A	N/A	N/A
	Reservation Demand-Interruptible			
	Distribution	$0.16	$0.17	6.3%
	Transmission	$0.15	$0.15	0.0%
	Reservation Demand-Firm			
	Distribution	$0.77	$0.79	2.6%
	Transmission	$0.75	$0.77	2.7%
	Daily Demand (On-Peak) Firm Standby			
	Distribution	$0.35	$0.36	2.9%
	Transmission	$0.35	$0.36	2.9%
	Daily Demand (On-Peak) Interruptible Standby			
	Distribution	$0.07	$0.07	0.0%
	Transmission	$0.07	$0.07	0.0%
	Non-Fuel Energy - On-Peak (¢ per kWh)			
	Distribution	0.739	0.762	3.1%
	Transmission	0.520	0.536	3.1%
	Non-Fuel Energy - Off-Peak (¢ per kWh)			
	Distribution	0.739	0.762	3.1%
	Transmission	0.520	0.536	3.1%
WIES-1	Wireless Internet Electric Service			
	Non-Fuel Energy (¢ per kWh)	18.735	19.326	3.2%
TR	Transformation Rider			
	Transformer Credit (per kW of Billing Demand)	($0.38)	($0.39)	2.6%
GSCU-1	GENERAL SERVICE CONSTANT USAGE			
	Customer Charge:	$9.77	$10.08	3.2%
	Non-Fuel Energy Charges:			
	Base Energy Charge (¢ per kWh)*	2.533	2.613	3.2%

* The non-fuel energy charges will be assessed on the Constant Usage kWh

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
HLFT-1	HIGH LOAD FACTOR – TIME OF USE			
	Customer Charge:			
	For customers with an Annual Maximum Demand less than 500 kW:	$40.59	$41.87	3.2%
	For customers with an Annual Maximum Demand less than 2000 kW:	$40.11	$41.37	3.1%
	For customers with an Annual Maximum Demand of 2000 kW or more:	$166.30	$171.54	3.2%
	Demand Charges:			
	On-peak Demand Charge:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$7.27	$7.50	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$7.26	$7.49	3.2%
	For customers with an Annual Maximum Demand 2000+ kW:	$7.26	$7.49	3.2%
	Maximum Demand Charge:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$1.55	$1.60	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$1.60	$1.65	3.1%
	For customers with an Annual Maximum Demand 2000+ kW:	$1.57	$1.62	3.2%
	Non-Fuel Energy Charges: (¢ per kWh)			
	Base Energy Charge (¢ per kWh):			
	On-Peak Period			
	For customers with an Annual Maximum Demand 21 - 499 kW:	1.645	1.697	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.517	0.533	3.1%
	For customers with an Annual Maximum Demand 2000+ kW:	0.517	0.533	3.1%
	Off-Peak Period			
	For customers with an Annual Maximum Demand 21 - 499 kW:	0.517	0.533	3.1%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.517	0.533	3.1%
	For customers with an Annual Maximum Demand 2000+ kW:	0.517	0.533	3.1%
SDTR	SEASONAL DEMAND -TIME OF USE RIDER			
	Customer Charge:			
	For customers with an Annual Maximum Demand less than 500 kW:			
	Otherwise applicable Rate Schedule GSD-1	$34.23	$35.31	3.2%
	Otherwise applicable Rate Schedule GSDT-1	$40.59	$41.87	3.2%
	For customers with an Annual Maximum Demand less than 2000 kW:	$40.11	$41.37	3.1%
	For customers with an Annual Maximum Demand of 2000 kW or more:	$166.30	$171.54	3.2%
	Demand and Energy Charges during June through September (SEASONAL):			
	Demand Charges:			
	Seasonal On-Peak Demand Charge per kW of Seasonal On-Peak Demand:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$5.89	$6.08	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$6.50	$6.70	3.1%
	For customers with an Annual Maximum Demand 2000+ kW:	$6.50	$6.70	3.1%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE WITH WCEC 1 GBRA	(4) PROPOSED RATE With GBRA WITH WCEC 2 GBRA	(5) PERCENT INCREASE [((4) - (3)) / (3)]
SDTR	SEASONAL DEMAND -TIME OF USE RIDER (continued)			
	Non-Fuel Energy Charges (¢ per kWh):			
	Base Seasonal Off-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	1.098	1.133	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.869	0.896	3.1%
	For customers with an Annual Maximum Demand 2000+ kW:	0.866	0.893	3.1%
	Base Seasonal On-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	4.156	4.287	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	3.181	3.281	3.1%
	For customers with an Annual Maximum Demand 2000+ kW:	3.173	3.273	3.2%
	OPTION A: Non-Seasonal Standard Rate			
	Demand Charges:			
	Non-Seasonal Demand Charge per kW of Non-Seasonal Maximum Demand:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$4.96	$5.12	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$5.90	$6.09	3.2%
	For customers with an Annual Maximum Demand 2000+ kW:	$5.90	$6.09	3.2%
	Non-Fuel Energy Charges: (¢ per Non-Seasonal kWh)			
	Non-Seasonal Energy Charge:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	1.440	1.485	3.1%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	1.139	1.175	3.2%
	For customers with an Annual Maximum Demand 2000+ kW:	1.136	1.172	3.2%
	OR			
	OPTION B: Non-Seasonal Time of Use Rate			
	Demand Charges per kW of Non-Seasonal Demand occurring during the Non-Seasonal On-Peak period:			
	Non-Seasonal Demand Charge :			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$4.96	$5.12	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$5.90	$6.09	3.2%
	For customers with an Annual Maximum Demand 2000+ kW:	$5.90	$6.09	3.2%
	OPTION B: Non-Seasonal Time of Use Rate			
	Non-Fuel Energy Charges: (¢ per kWh)			
	Non-Seasonal On-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	3.360	3.466	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	2.257	2.328	3.1%
	For customers with an Annual Maximum Demand 2000+ kW:	2.370	2.445	3.2%
	Non-Seasonal Off-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	0.924	0.953	3.1%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.685	0.707	3.2%
	For customers with an Annual Maximum Demand 2000+ kW:	0.641	0.661	3.1%

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power) Cost Recovery Clause and Generating) Performance Incentive Factor))	DOCKET NO. 080001-EI FILED: September 2, 2008

AFFIDAVIT

STATE OF FLORIDA
MIAMI-DADE COUNTY

BEFORE ME, the undersigned authority, personally appeared Steven R. Sim who, being first duly sworn deposes and says:

1. My name is Steven R. Sim and I am currently employed by Florida Power & Light Company ("FPL") as Senior Manager in the Resource Assessment & Planning ("RAP") Department.

2. I graduated from the University of Miami (Florida) with a Bachelor's degree in Mathematics in 1973. I subsequently earned a Master's degree in Mathematics from the University of Miami (Florida) in 1975 and a Doctorate in Environmental Science and Engineering from the University of California at Los Angeles ("UCLA") in 1979. In 1979 I joined FPL. From 1979 until 1991 I worked in various departments including Marketing, Energy Management Research, and Load Management, where my responsibilities concerned the development, monitoring, and cost- effectiveness of demand side management ("DSM") programs. In 1991 I joined my current department, then named the System Planning Department, as a Supervisor whose responsibilities included the cost- effectiveness analyses of a variety of individual supply and DSM options. In 2007 I assumed my present position.

3. In my role as Senior Manager in the RAP department, I oversee work designed to determine the magnitude and timing of FPL's resource needs and then develop the integrated resource plan through which FPL will meet those resource needs.

4. In 2005 FPL issued a Request for Proposal ("RFP") for capacity needs in 2009 - 2011 after the RAP department performed the work described above. In addition to my involvement in developing the RFP, I was responsible for performing the economic evaluation of West County Energy Center (WCEC) units

1 and 2and all capacity options received in response to the RFP. Through this RFP process, WCEC units 1 and 2 were selected as the best option to meet the future capacity needs of FPL's customers. Subsequent to the RFP process that selected WCEC 1 and 2 and, pursuant to the Florida Power Plant Siting Act ("PPSA"), the Florida Public Service Commission ("FPSC") issued Order No. PSC-06-0555-FOF-EI in Docket No. 060225-EI granting FPL's Petition for a Determination of Need to build WCEC Units 1 and 2. The Final Order of Certification under the PPSA was issued by the Governor and Cabinet sitting as the Siting Board on December 26, 2006.

5. The purpose of my affidavit and supporting documentation is to provide the base revenue requirements for the first 12-months of operation for WCEC units 1 and 2 that Renae Deaton uses to compute the Generation Base Rate Adjustment pursuant to the Stipulation and Settlement Agreement approved by the Commission in Docket No. 050045-EI. Those base revenue requirements are as follows:

For WCEC unit 1:

a) Capital Cost	$125.1 million
b) Fixed O&M and Capital Replacement	$ 14.3 million
c) Variable O&M	$ 1.3 million
d) Total base revenue requirements for first 12 months	$140.7 million

For WCEC unit 2:

a) Capital Cost	$115.1 million
b) Fixed O&M and Capital Replacement	$ 12.7 million
c) Variable O&M	$ 1.3 million
d) Total base revenue requirements for first 12 months	$129.1 million

These first 12-month base revenue requirements were calculated using the projected total installed cost value of \$688.6 million for WCEC unit 1 and \$632.4 million for WCEC unit 2, and reflected in the Company's Petition for a Determination of Need and upon which Order No. PSC-06-0555-FOF-EI was based, using a rate of return on equity of 11.75% in accordance with the Stipulation and Settlement Agreement approved in Order No. PSC-05-0902-S-EI in Docket No. 050045-EI, and based on in-service dates of June 1, 2009 for WCEC unit 1 and June 1, 2010 for WCEC unit 2.

6. The input values for the base revenue requirements are as follows for WCEC unit 1 (in 2009 \$):

a.	Installed Capital cost =	\$688.6 million
b.	Fixed O&M cost =	\$4.61/kw-year
c.	Capital Replacement cost =	\$7.04/kw-year
d.	Variable O&M cost =	\$0.138/mwh

The input values for the base revenue requirements are as follows for WCEC unit 2 (in 2010 \$):

a.	Installed Capital cost =	\$632.4 million
b.	Fixed O&M cost =	\$3.07/kw-year
c.	Capital Replacement cost =	\$7.04/kw-year
d.	Variable O&M cost =	\$0.138/mwh

These cost input values are found on page J-1 of 1 of Appendix J of FPL's Need Study for Electrical Power Plant 2009 ("Need Study") document submitted in Docket No. 060225-EI. The capital cost values are also presented separately in Table III.G.1 on page 21 of the Need Study.

7. Attachment I provides the separate revenue requirement calculations for Capital, for Fixed O&M and Capital Replacement, and for Variable O&M. The document shows how the above 12-month values were calculated using the cost information previously provided in FPL's Need filing in Confidential Appendix C-3, "Fixed Cost Spreadsheets for Portfolios", and in Confidential Appendix C-4, "P-MArea Cases

for All Portfolios". Confidential Appendix C-3 provided the capital, fixed O&M, and capital replacement costs used above in the 12-month cost calculation and Confidential Appendix C-4 provided the variable O&M costs used above in the 12-month cost calculation.

8. In conclusion, the base revenue requirements for the first 12 months of operation are $140.7 million for WCEC unit 1 and are $129.1 million for WCEC unit 2. These values were calculated using the same starting point values and assumptions included in FPL's Need filing.

Steven R. Sim

Steven R. Sim

I hereby certify that on this 29 day of August, 2008 before me, an officer duly authorized in the State and County aforesaid to take acknowledgements, personally appeared Steven R. Sim who is personally known to me, and he acknowledged before me that he executed this certification of signature as his free act and deed who did not take an oath.

I witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as this 29 day of August, 2008.

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

Monica Lynn Padron

Notary Public

State of Florida

My Commission Expires: 12/18/10

Attachment 1

I. First 12-Month GBRA Costs for WCEC Unit 1:

a) Full-Year GBRA-Category Revenue Requirements:

Year	Capital Revenue Requirements (million $)	Fixed O&M Revenue Requirements (million $)	Variable O&M Revenue Requirements (million $)	Capital Replacement Revenue Requirements (million $)	Total Revenue Requirements (million $)
2009	73.9	3.3	0.7	5.0	82.9
2010	122.8	5.9	1.3	8.7	138.6

b) First 12-Month GBRA-Category Revenue Requirements: (includes 5 months of costs for 2010)

Year	Capital Revenue Requirements (million $)	Fixed O&M Revenue Requirements (million $)	Variable O&M Revenue Requirements (million $)	Capital Replacement Revenue Requirements (million $)	Total Revenue Requirements (million $)
2009	73.9	3.3	0.7	5.0	82.9
2010	51.2	2.5	0.5	3.6	57.8
	125.1	5.7	1.3	8.6	**140.7**

II. First 12-Month GBRA Costs for WCEC Unit 2:

a) Full-Year GBRA-Category Revenue Requirements:

Year	Capital Revenue Requirements (million $)	Fixed O&M Revenue Requirements (million $)	Variable O&M Revenue Requirements (million $)	Capital Replacement Revenue Requirements (million $)	Total Revenue Requirements (million $)
2010	68.0	2.3	0.7	5.1	76.1
2011	113.0	4.1	1.3	8.8	127.2

b) First 12-Month GBRA-Category Revenue Requirements: (includes 5 months of costs for 2011)

Year	Capital Revenue Requirements (million $)	Fixed O&M Revenue Requirements (million $)	Variable O&M Revenue Requirements (million $)	Capital Replacement Revenue Requirements (million $)	Total Revenue Requirements (million $)
2010	68.0	2.3	0.7	5.1	76.1
2011	47.1	1.7	0.5	3.7	53.0
	115.1	4.0	1.3	8.7	**129.1**

APPENDIX I

FUEL COST RECOVERY

EXHIBIT GJY-3

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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 2009

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
1.0% Sulfur Grade ($/Bbl)	107.94	107.64	107.29	107.09	107.61	108.01	108.31	108.61	108.71	108.69	108.66	108.86
1.0% Sulfur Grade ($/mmBtu)	16.87	16.82	16.76	16.73	16.81	16.88	16.92	16.97	16.99	16.98	16.98	17.01

Light Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.05% Sulfur Grade ($/Bbl)	151.28	152.12	151.81	150.32	148.91	147.90	147.75	148.07	148.68	149.35	150.02	150.65
0.05% Sulfur Grade ($/mmBtu)	25.95	26.09	26.04	25.78	25.54	25.37	25.34	25.40	25.50	25.62	25.73	25.84

Natural Gas Transportation	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT (mmBtu/Day)	750,000	750,000	750,000	839,000	874,000	874,000	874,000	874,000	874,000	839,000	750,000	750,000
Firm Gulfstream (mmBtu/Day)	535,000	535,000	535,000	535,000	535,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000
Non-Firm FGT (mmBtu/Day)	140,000	140,000	140,000	110,000	50,000	50,000	50,000	50,000	50,000	110,000	140,000	140,000
Non-Firm Gulfstream (mmBtu/Day)	280,000	280,000	140,000	80,000	80,000	50,000	50,000	50,000	50,000	110,000	140,000	140,000
Total Projected Daily Availability (mmBtu/Day)	1,705,000	1,705,000	1,565,000	1,564,000	1,539,000	1,669,000	1,669,000	1,669,000	1,669,000	1,754,000	1,725,000	1,725,000
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

**Note: The SESH 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 ($/mmBtu)	10.43	10.45	10.28	9.77	9.74	9.83	9.94	10.01	10.05	10.14	10.39	10.79
Firm Gulfstream ($/mmBtu)	10.16	10.18	10.02	9.52	9.48	9.58	9.68	9.75	9.79	9.88	10.13	10.52
Non-Firm FGT ($/mmBtu)	10.67	10.70	10.53	10.07	10.18	10.39	10.50	10.57	10.49	10.43	10.64	11.04
Non-Firm Gulfstream ($/mmBtu)	10.76	10.78	10.62	10.12	10.08	10.17	10.28	10.35	10.39	10.48	10.72	11.11

Coal	January	February	March	April	May	June	July	August	September	October	November	December
Scherer ($/mmBtu)	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26
SJRPP ($/mmBtu)	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2009

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral 1	2.1	3.5	0.0	NONE			
Cape Canaveral 2	2.0	3.8	0.0	NONE			
Cutler 5	0.4	0.2	10.4	04/04/09 - 05/11/09			
Cutler 6	1.8	0.9	20.0	09/26/09 - 12/07/09			
Lauderdale 4	1.3	3.8	6.8	03/28/09 - 04/21/09			
Lauderdale 5	1.4	3.9	2.5	10/03/09 - 10/11/09			
Lauderdale GTs	1.0	7.2	0.0	NONE			
Fort Myers 2 CC	1.4	3.8	1.9	02/21/09 - 03/27/09 *			
Ft. Myers 3	3.0	3.2	0.0	NONE			
Ft. Myers GTs	0.3	1.3	0.9	05/02/09 - 05/21/09 *			
Manatee 1	0.8	2.6	0.0	NONE			
Manatee 2	0.7	2.8	20.0	02/21/09 - 05/04/09			
Manatee 3	2.4	3.1	1.9	09/12/09 - 10/09/09			
Martin 1	1.0	2.8	0.0	NONE			
Martin 2	0.8	3.4	17.8	09/19/09 - 11/22/09			
Martin 3	2.4	3.1	3.8	09/05/09 - 09/18/09			
Martin 4	2.5	2.7	2.9	10/03/09 - 10/23/09 *			
Martin 8 CC	2.3	3.2	7.7	05/16/09 - 06/12/09 *	10/10/09 - 10/30/09		
Port Everglades 1	3.2	1.5	0.0	NONE			
Port Everglades 2	2.3	1.8	25.5	09/12/09 - 12/13/09			
Port Everglades 3	2.2	5.4	6.0	03/28/09 - 04/18/09			
Port Everglades 4	2.3	5.0	0.0	NONE			
Port Everglades GTs	1.9	9.7	0.0	NONE			
Putnam 1	0.4	0.9	1.6	09/19/09 - 09/30/09 *			
Putnam 2	0.4	0.9	21.5	03/14/09 - 05/08/09	10/03/09 - 11/16/09 *		
Riviera 3	2.5	5.5	5.8	02/28/09 - 03/20/09			
Riviera 4	2.2	5.1	0.0	NONE			
Sanford 3	1.0	0.7	17.3	01/31/09 - 04/03/09			
Sanford 4 CC	1.4	3.9	5.8	09/26/09 - 11/06/09 *			
Sanford 5 CC	1.4	3.9	3.8	01/17/09 - 01/30/09 *	06/06/09 - 06/19/09 *	09/12/09 - 09/25/09 *	11/07/09 - 11/20/09 *
Turkey Point 1	1.8	5.4	18.1	02/07/09 - 04/13/09			
Turkey Point 2	2.4	4.8	0.0	NONE			
Turkey Point 3	1.1	1.1	9.6	03/01/09 - 04/05/09			
Turkey Point 4	1.1	1.1	11.0	10/25/09 - 12/04/09			
Turkey Point 5	2.4	3.2	4.9	05/30/09 - 06/16/09 *	06/13/09 - 06/30/09 *		
St. Lucie 1	1.2	1.2	0.0	NONE			
St. Lucie 2	1.1	1.1	9.9	04/27/09 - 06/02/09			
Saint Johns River Power Park 1	1.6	1.1	16.2	02/28/09 - 04/27/09			
Saint Johns River Power Park 2	1.9	0.9	0.0	NONE			
Scherer 4	1.9	1.0	0.0	NONE			
West County 1	3.9	0.0	0.0	NONE			
West County 2	3.0	0.0	0.0	NONE			

* Partial Planned Outage

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FUEL COST RECOVERY

2009 RISK MANAGEMENT PLAN

GJY-4

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FUEL COST RECOVERY

2009 RISK MANAGEMENT PLAN

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Florida Power and Light Company (FPL)
2009 Risk Management Plan

FPL recognizes the importance of managing price volatility in the fuel and power it purchases to provide electric service to its customers. Further, FPL recognizes that the greater the proportion of a particular energy source it relies upon to provide electric services to its customers, the greater the importance of managing price volatility associated with that energy source.

FPL's risk management plan is based on the following guiding principles:

a) A well-managed hedging program does not involve speculation or market timing. Its primary purpose is not to reduce FPL's fuel costs paid over time, but rather to reduce the variability or volatility in fuel costs over time.

b) Hedging can result in significant lost opportunities for savings in the fuel costs to be paid by customers, if fuel prices actually settle at lower levels than at the time that hedges were placed. FPL does not predict or speculate on whether markets will ultimately rise or fall and actually settle higher or lower than the price levels that existed at the time hedges were put into place.

c) Market prices and forecasts of market prices have experienced significant volatility and are expected to continue to be highly volatile and, therefore, FPL does not intend to "outguess the market" in choosing the specific timing for effecting hedges or the percentage or volume of fuel hedged.

d) In order to balance the goal of reducing customers' exposure to rising fuel prices against the goal of allowing customers to benefit from falling fuel prices, it is appropriate to hedge a portion of the total expected volume of fuel purchases.

This Risk Management Plan includes supplemental information in response to recommendations in Staff's recent *Review of Fuel Procurement Hedging Practices of Florida's Investor-Owned Electric Utilities.*

Overall Quantitative and Qualitative Risk Management Objectives (TFB-4, Item 1)

FPL's risk management objectives are to effectively execute a well-disciplined and independently controlled fuel hedging strategy to achieve the goals of fuel price stability (volatility minimization) and asset optimization. FPL's fuel hedging strategy aims to reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL's customers.

Fuel Procurement Risks (TFB-4, Item 3)

FPL encounters several potential risks associated with its fuel procurement activities. These risks are grouped into four categories as detailed below:

Market Risk
The risk of changes in economic fair value due to fluctuations in market prices, volatility, correlation, and interest rates will have a direct impact on any open or unhedged energy positions. The utility determines acceptable levels of risk for fuel procurement by performing various analyses that include forecasted/expected levels of activity, forecasted price levels and price changes, price volatility, and Value-at-Risk (VaR) calculations. The analyses are then presented to the Exposure Management Committee (EMC) for review and approval. The EMC is comprised of executive and senior management and has responsibility for developing and approving the company's risk strategies and objectives, including the overall hedging strategy. Approval is given to remain within specified VaR limits.

Credit Risk
Credit risk management includes appropriate creditworthiness review and monitoring processes, the request for collateral if deemed necessary, and the inclusion of contractual risk mitigation terms and conditions whenever possible. Such credit risk mitigations include collateral threshold amounts, cross default amounts, payment netting, and set-off agreements.

Liquidity Risk
Transacting Liquidity: The availability of market participants willing to transact or having credit quality to transact will have an impact on the utility's ability to execute hedging and risk management strategies.

Short-Term Funding Liquidity: Changes in underlying market parameters may impact movements of cash in relation to business activities. Positions that are balanced for fair value purposes, but unbalanced for cash flow purposes, may give rise to large swings in cash balances.

Operational Risk
The physical risk associated with maintaining and operating generation assets. The potential risks that FPL encounters with its physical fuel procurement are fuel supply and transportation availability, product quality, delivery timing, weather, environmental, and supplier failure to deliver.

Fuel Procurement Oversight/Policies and Procedures (TFB-4, Items 4, 5, 6, 7 and 9)

FPL provides its fuel procurement activities with independent oversight.

The President of FPL is responsible for authorizing all hedging activities. Changes in strategies and any deviations from the program are approved by the President of FPL prior to execution. In the absence of the President of FPL, the Chief Operating Officer (COO) or the Chief Financial Officer (CFO) of FPL Group may also authorize any changes in strategies and deviations from the program. Program activity is included in the Monthly Operations Performance Review (MOPR) chaired by the Chief Executive Officer (CEO). In addition, the EMC meets monthly to review performance and discuss current procurement/hedging activities and monitors daily results of procurement activity.

The utility has a separate and independent middle office Risk Management department that provides oversight of fuel procurement activities. FPL has formal Policy and Procedures documents, signed by all employees, which include controls specifically related to the fuels hedging program. The Risk Management department ensures that the approved execution strategies are followed for each program. Daily, weekly, and monthly reporting is performed by the Risk Management department and distributed to a wide audience, including executive management. Credit reviews are performed by the Risk Management department and included in the reporting mentioned above. Execution strategies must be approved prior to the execution of any transactions and documented as a Planned Position Strategy (PPS). All hedge transactions are to be addressed within this strategy document. FPL is attaching two PPS documents with this plan; (1) a PPS that details FPL's hedging strategy for 2009; and (2) a PPS that details FPL's re-balancing strategy for 2009. FPL considers its PPS documents to be confidential. FPL has not created PPS documents for 2010 at this point.

<u>Policy and Procedures</u>

As part of this Risk Management Plan, FPL is attaching the latest FPL Group, Inc. Energy Trading and Risk Management Policy (Policy) and Trading and Risk Management Procedures Manual (Procedures). FPL updates the Policy and Procedures as necessary. For details that are not covered in this document, please refer to the Policy and Procedures. FPL considers its Policy and Procedures to be confidential.

FPL's corporate risk Policy delineates individual and group transaction limits and authorizations for all fuel procurement activities.

The Policy sets out FPL Group's approach to energy risk and the management of risk, as follows:

- Identification and definition;
- Quantification and measurements;

- Reporting;
- Authority to transact; and
- Ownership and roles and responsibilities.

The Procedures provide guidance that will promote efficient and accurate processing of transactions, effective preparation and distribution of information relating to trading and marketing activities, and efficient monitoring of the portfolio of risks, all within a well-controlled environment.
The Procedures define VaR and duration limits for all forward activity, by portfolio. In addition, individual procurement strategies must be documented and approved by front and middle office management prior to deal execution.

FPL's deal execution and capture functions coordinate activities across relevant departments, personnel, and systems. This framework of activity properly links the responsibilities of personnel and provides a sufficient medium to resolve issues.

The Procedures clearly list authorized trading personnel, trading limits, tenors, and acceptable instruments. Access to the data entry privileges in the deal capture system is limited to only those individuals who are formally granted permissions to enter trades. All transactions are entered and managed through a centralized deal capture system that supports routine reporting, settlements, and review. Transaction record editing is managed through acceptable authorizations and processes. Credit information is available to traders on a timely basis through daily reporting produced by the credit section of the Risk Management department. Auditable records of all transactions are gathered and reviewed on a regular basis.

Deal Execution Details
FPL traders receive daily credit reports and credit watch lists from the Risk Management department to ensure that FPL does not enter into a trade with an unauthorized counterparty. FPL traders then select counterparties from this list to transact with as the hedging program is executed. FPL uses a market comparison approach to execute financial hedges. For natural gas, real-time prices can be observed by FPL through electronic tools, such as ICE (InterContinental Exchange), FutureSource, or over-the-counter brokers. Residual fuel oil swaps are not an exchange traded commodity and hence competing prices from counterparties, over-the-counter broker quotes, along with observed trends in crude oil prices, and estimated price differentials to crude oil prices, are used to determine the market value.

FPL traders generally execute trades with counterparties offering the best price for a given instrument. However, in a case where two or more counterparties are offering similar pricing, the traders will attempt to execute trades with the counterparty that has the least amount of credit exposure with FPL. This is done primarily to allow FPL to spread its risk among as many counterparties as possible, but also affords the advantage of preventing the inadvertent telegraphing of FPL's commercial intentions to the market, thus helping to ensure favorable pricing for FPL's hedges.

2008 Hedging Strategy (TFB-4, Items 2 and 8)

The principal focus of this Risk Management Plan, as will be the case for future plans, is on the hedging strategy that FPL intends to implement in the upcoming year for placing hedges on fuel purchases in the year or years thereafter. For example, as discussed below, FPL is presenting its 2009 hedging strategy that will apply to hedging FPL's projected 2010 fuel oil and natural gas requirements. However, for transitional purposes FPL is also including in this year's plan information pertaining to its 2008 hedging strategy for projected 2009 natural gas and heavy fuel oil requirements.

FPL plans to hedge a portion of its projected 2009 residual fuel oil and natural gas requirements during 2008. Absent special circumstances (e.g. a hurricane that FPL concludes will substantially impair market functions). FPL is implementing its 2008 hedging program within the following parameters:

Natural Gas

1) FPL will hedge approximately [redacted] of its projected 2009 natural gas requirements within the Hedging Window during 2008. This hedge percentage is within FPL's system base load requirements. FPL will hedge approximately [redacted] of each individual month's projected natural gas requirements.
2) FPL will utilize [redacted] to hedge its projected natural gas requirements.
3) FPL will execute its natural gas hedges for 2009 from [redacted] through [redacted] as shown below:

Hedging Window

[redacted]

During each month of the Hedging Window, FPL will hedge the percentages shown of its projected 2009 natural gas requirements. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.

4) Re-balancing will be executed per the attached PPS. Once the initial monthly target volumes have been hedged, rebalancing will be executed to maintain the hedge percentages inside approved tolerance bands. The monthly tolerance bands for natural gas are +/- [redacted]. Therefore, the minimum and maximum monthly hedge percentages are [redacted] and [redacted] respectively.

Heavy Fuel Oil

1) FPL will hedge approximately [redacted] of its projected 2009 heavy fuel oil requirements. This represents a lower hedge percentage compared with previous years and is primarily driven by FPL's fuel switching capability. FPL dispatches its system based on real-time fuel prices which allows FPL to burn the lowest cost fuel at its dual-fired facilities on a daily basis. This fuel switching capability has caused significant variances in projected versus actual heavy fuel oil burns, particularly in the shoulder months (November – March). Therefore, FPL believes that a lower hedge percentage for fuel oil is appropriate to help mitigate the potential for being "over hedged". FPL will hedge approximately [redacted] of each individual month's projected heavy fuel oil requirements.
2) FPL will utilize [redacted] to hedge its projected heavy fuel oil requirements.
3) FPL will execute its heavy fuel oil hedges for 2009 from [redacted] through [redacted] as shown below:

Hedging Window

[redacted]

During each month of the Hedging Window, FPL will hedge the percentages shown of its projected 2009 heavy fuel oil requirements. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.

4) Re-balancing will be executed per the attached PPS. Once the initial monthly target volumes have been hedged, rebalancing will be executed to maintain the hedge percentages inside approved tolerance bands. The monthly tolerance bands for heavy fuel oil are +/- [redacted]. Therefore, the minimum and maximum monthly hedge percentages are [redacted] and [redacted] respectively.

__2009 Hedging Strategy (TFB-4, Items 2 and 8)__

FPL plans to hedge a portion of its projected 2010 residual fuel oil and natural gas requirements during 2009. Absent special circumstances (e.g. a hurricane that FPL concludes will substantially impair market functions). FPL will implement its hedging program within the following parameters:

Natural Gas

1) FPL will hedge approximately [redacted] of its projected 2010 natural gas requirements within the Hedging Window during 2009. This hedge percentage is consistent with 2009 hedge levels and is within FPL's

system base load requirements. FPL will hedge approximately [redacted] of each individual month's projected natural gas requirements.

2) FPL will utilize [redacted] to hedge its projected natural gas requirements.

3) FPL will execute its natural gas hedges for 2010 from [redacted] through [redacted] as shown below:

Hedging Window

[redacted]

During each month of the Hedging Window, FPL will hedge the percentages shown of its projected 2010 natural gas requirements. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.

4) FPL intends to rebalance its natural gas hedge positions during the year based on changes in forecasted market prices, projected unit outage schedules or changes in FPL's load forecast. Once the initial monthly target volumes have been hedged, rebalancing will be executed to maintain the hedge percentages inside approved tolerance bands. The monthly tolerance bands for natural gas are +/- [redacted] Therefore, the minimum and maximum monthly hedge percentages are [redacted] and [redacted] respectively.

Heavy Fuel Oil

1) FPL will hedge approximately [redacted] of its projected 2010 heavy fuel oil requirements. This hedge percentage is consistent with 2009 hedge levels. FPL will hedge approximately [redacted] of each individual month's projected heavy fuel oil requirements.

2) FPL will utilize [redacted] to hedge its projected heavy fuel oil requirements.

3) FPL will execute its heavy fuel oil hedges for 2010 from [redacted] through [redacted] as shown below:

Hedging Window

[redacted]

During each month of the Hedging Window, FPL will hedge the percentages shown of its projected 2010 heavy fuel oil requirements. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.

4) FPL intends to rebalance its heavy oil hedge positions during the year based on changes in forecasted market prices, projected unit outage schedules or changes in FPL's load forecast. Once the initial monthly target volumes have been hedged, rebalancing will be executed to maintain the hedge percentages inside approved tolerance bands. The monthly tolerance bands for heavy fuel oil are +/- [redacted]. Therefore, the minimum and maximum monthly hedge percentages are [redacted] and [redacted] respectively.

Hedging Window Modification

Market price behaviors are changing constantly [redacted]

Reporting System for Fuel Procurement Activities (TFB-4, Items 13 and 14)

FPL reporting systems comprehensively identify, measure, and monitor all forms of risk associated with fuel procurement activities.

FPL's philosophy on reporting is that it should be timely, consistent, flexible, and transparent. Timely and consistent reporting of risk information is critical to the effective management of risk. The utility has sufficient systems capability for identifying, measuring, and monitoring all types of risk associated with fuel procurement activities. These systems include: deal capture, a database for maintaining current and historical pricing, deal information, and valuation models, and a reporting system that utilizes the information in the trade capture system and the database.
Specifically, several reports are available at FPL to monitor risk:

Daily Management Report

For each business day there should be a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report should detail the current energy, spot and forward, unrealized profit and loss, VaR, and position amounts. This report should be published only after proper and thorough discussion between Risk Management and desk heads, if necessary for clarification, and resolution of any issues raised.

Credit Exposure Reporting

For each business day there should be a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report should detail:

- Credit exposure against available limits, highlighting instances in which exposure exceeds available limits; and
- Current credit liabilities.

Exposure Management Committee Update

The Vice President Trading & Risk Management will provide a formal update to the EMC on a monthly basis. The agenda for the update will be agreed in advance with the EMC Chairman, but should as a minimum contain the following items:

Minutes of previous EMC update for approval;

- Summary and explanation of significant changes in market risk and fair value, including VaR backtesting results;
- Summary and explanation of significant changes in credit risk; and
- Exception to Risk Management Policy.

Hedge Program Limitations (TFB-4, Item 15)

FPL does not currently have any limitations in implementing certain hedging techniques that would provide a net benefit to customers.

Energy Marketing & Trading

A division of Florida Power & Light Company.

Trading and Risk Management

Procedures Manual

Revision: December 18, 2007

Approved By: _______________

(If the original signature is needed, please contact Risk Management at 304-5710)

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

TRADING AND RISK MANAGEMENT PROCEDURES MANUAL

ENERGY
MARKETING & TRADING
a division of Florida Power & Light Company

FPL Energy
Power Marketing, Inc.

APPROVED BY THE EMC ON:

December 18 ,2007

(See EMC Meeting Minutes dated December 18 , 2007. Please contact Risk Management at 304-5710)

FPL Group, Inc.
Energy Trading and Risk Management Policy

FPL
Energy Services

Gexa ENERGY

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

ENERGY TRADING AND RISK MANAGEMENT POLICY

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

PLANNED POSITIONS STRATEGY

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES

KMD-5
DOCKET NO. 080001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT ________
PAGES 1-74
SEPTEMBER 2, 2008

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES
January 2009 – December 2009

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FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2009 -MAY 2009

		(a) DOLLARS		(b) MWH	(c) ¢/KWH
1	Fuel Cost of System Net Generation (E3)	$6,214,273,493		97,654,973	6.3635
2	Nuclear Fuel Disposal Costs (E2)	21,828,572		23,509,501	0.0929
3	Fuel Related Transactions (E2)	2,611,519		0	0.0000
3a	Adjustment for WCEC 1 and 2	164,850,000		0	0.0000
4	Incremental Hedging Costs (E2)	694,510		0	
5	Fuel Cost of Sales to FKEC / CKW (E2)	(76,920,848)		(1,046,781)	7.3483
6	TOTAL COST OF GENERATED POWER	$6,327,337,245		96,608,192	6.5495
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	351,329,743		11,735,650	2.9937
8	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	37,799,891		377,794	10.0054
9	Energy Cost of Other Econ Purch (Non-Florida) (E9)	78,482,053		818,206	9.5920
10	Payments to Qualifying Facilities (E8)	235,952,993		5,572,282	4.2344
11	TOTAL COST OF PURCHASED POWER	$703,564,680		18,503,933	3.8022
12	TOTAL AVAILABLE KWH (LINE 6 + LINE 11)			115,112,124	
13	Fuel Cost of Economy Sales (E6)	(112,997,486)		(1,491,500)	7.5761
14	Gain on Economy Sales (E6)	(18,447,799)		(2,028,902)	0.9093
15	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(3,092,615)		(537,402)	0.5755
16	Fuel Cost of Other Power Sales (E6)	0		0	0.0000
16a	TOTAL FUEL COST AND GAINS OF POWER SALES	($134,537,900)		(2,028,902)	6.6311
19	Net Inadvertent Interchange	0		0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 6 + 11 + 18)	$6,896,364,025		113,083,222	6.0985
21	Net Unbilled Sales	(44,697,230)	**	(732,923)	(0.0421)
22	Company Use	20,689,092	**	339,250	0.0195
23	T & D Losses	448,263,662	**	7,350,409	0.4224
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$6,896,364,025		106,126,486	6.4982
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$8,874,931		136,572	6.4982
26	Jurisdictional MWH Sales	$6,887,489,094		105,989,914	6.4982
27	Jurisdictional Loss Multiplier	-		-	1.00056
28	Jurisdictional MWH Sales Adjusted for Line Losses	$6,891,346,088		105,989,914	6.5019
29	FINAL TRUE-UP Jan 07- Dec 07 (a) / EST/ACT TRUE-UP Jan 08 - Dec 08 $296,048.402 underrecovery	296,048,402		105,989,914	0.2793
30	TOTAL JURISDICTIONAL FUEL COST	$7,187,394,490		105,989,914	6.7812
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes	7,192,569,414			6.7861
33	GPIF ***	$5,383,572		105,989,914	0.0051
33a	WCEC 1 and 2 Jurisdictionalized Savings	($18,597,500)		39,665,860	(0.0469)
34	Fuel Factor including GPIF (Line 32 + Line 33)	7,179,355,486		105,989,914	6.7443
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH				6.744

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

(a) 2007 Final True-Up under-recovery of $121,036,106 included in August -December 2008 mid-course correction factor

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JUNE 2009 - OCTOBER 2009

		(a) DOLLARS	(b) MWH	(c) ¢/KWH
1	Fuel Cost of System Net Generation (E3)	$6,214,273,493	97,654,973	6.3635
2	Nuclear Fuel Disposal Costs (E2)	21,828,572	23,509,501	0.0929
3	Fuel Related Transactions (E2)	2,611,519	0	0.0000
3a	Adjustment for WCEC 1 and 2	164,850,000	97,654,973	0.1688
4	Incremental Hedging Costs (E2)	694,510	0	
5	Fuel Cost of Sales to FKEC / CKW (E2)	(76,920,848)	(1,046,781)	7.3483
6	TOTAL COST OF GENERATED POWER	$6,327,337,245	96,608,192	6.5495
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	351,329,743	11,735,650	2.9937
8	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	37,799,891	377,794	10.0054
9	Energy Cost of Other Econ Purch (Non-Florida) (E9)	78,482,053	818,206	9.5920
10	Payments to Qualifying Facilities (E8)	235,952,993	5,572,282	4.2344
11	TOTAL COST OF PURCHASED POWER	$703,564,680	18,503,933	3.8022
12	TOTAL AVAILABLE KWH (LINE 5 + LINE 13)		115,112,124	
13	Fuel Cost of Economy Sales (E6)	(112,997,486)	(1,491,500)	7.5761
14	Gain on Economy Sales (E6)	(18,447,799)	(2,028,902)	0.9093
15	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(3,092,615)	(537,402)	0.5755
16	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
16a	TOTAL FUEL COST AND GAINS OF POWER SALES	($134,537,900)	(2,028,902)	6.6311
19	Net Inadvertent Interchange	0	0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 6 + 11 + 18)	$6,896,364,025	113,083,222	6.0985
21	Net Unbilled Sales	(44,697,243) **	(732,924)	(0.0421)
22	Company Use	20,689,092 **	339,250	0.0195
23	T & D Losses	448,263,662 **	7,350,409	0.4224
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$6,896,364,025	106,126,486	6.4982
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$8,874,931	136,572	6.4982
26	Jurisdictional MWH Sales	$6,887,489,094	105,989,914	6.4982
27	Jurisdictional Loss Multiplier	-	-	1.00056
28	Jurisdictional MWH Sales Adjusted for Line Losses	$6,891,346,088	105,989,914	6.5019
29	FINAL TRUE-UP Jan 07- Dec 07 (a) / EST/ACT TRUE-UP Jan 08 - Dec 08 $296,048,402 underrecovery	296,048,402	105,989,914	0.2793
30	TOTAL JURISDICTIONAL FUEL COST	$7,187,394,490	105,989,914	6.7812
31	Revenue Tax Factor			1.00072
32	Fuel Factor Adjusted for Taxes	7,192,569,414		6.7861
33	GPIF ***	$5,383,572	105,989,914	0.0051
33a	WCEC 1 and 2 Jurisdictionalized Savings	($93,085,358)	49,552,905	(0.1880)
34	Fuel Factor including GPIF (Line 32 + Line 33)	7,197,952,986	105,989,914	6.6032
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			6.603

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

(a) 2007 Final True-Up under-recovery of $121,036,106 included in August -December 2008 mid-course correction factor

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: NOVEMBER 2009 - DECEMBER 2009

		(a)	(b)	(c)
		DOLLARS	MWH	¢/KWH
1	Fuel Cost of System Net Generation (E3)	$6,214,273,493	97,654,973	6.3635
2	Nuclear Fuel Disposal Costs (E2)	21,828,572	23,509,501	0.0929
3	Fuel Related Transactions (E2)	2,611,519	0	0.0000
3a	Adjustment for WCEC 1 and 2	164,850,000	97,654,973	0.1688
4	Incremental Hedging Costs (E2)	694,510	0	
5	Fuel Cost of Sales to FKEC / CKW (E2)	(76,920,848)	(1,046,781)	7.3483
6	TOTAL COST OF GENERATED POWER	$6,327,337,245	96,608,192	6.5495
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	351,329,743	11,735,650	2.9937
8	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	37,799,891	377,794	10.0054
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10	Payments to Qualifying Facilities (E8)	235,952,993	5,572,282	4.2344
11	TOTAL COST OF PURCHASED POWER	$703,564,680	18,503,933	3.8022
12	TOTAL AVAILABLE KWH (LINE 5 + LINE 13)		115,112,124	
13	Fuel Cost of Economy Sales (E6)	(112,997,486)	(1,491,500)	7.5761
14	Gain on Economy Sales (E6)	(18,447,799)	(2,028,902)	0.9093
15	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(3,092,615)	(537,402)	0.5755
16	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
16a	TOTAL FUEL COST AND GAINS OF POWER SALES	($134,537,900)	(2,028,902)	6.6311
19	Net Inadvertent Interchange	0	0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 6 + 11 + 18)	$6,896,364,025	113,083,222	6.0985
21	Net Unbilled Sales	(44,697,243) **	(732,924)	(0.0421)
22	Company Use	20,689,092 **	339,250	0.0195
23	T & D Losses	448,263,662 **	7,350,409	0.4224
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$6,896,364,025	106,126,486	6.4982
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$8,874,931	136,572	6.4982
26	Jurisdictional MWH Sales	$6,887,489,094	105,989,914	6.4982
27	Jurisdictional Loss Multiplier	-	-	1.00056
28	Jurisdictional MWH Sales Adjusted for Line Losses	$6,891,346,088	105,989,914	6.5019
29	FINAL TRUE-UP Jan 07- Dec 07 (a) / EST/ACT TRUE-UP Jan 08 - Dec 08 $296,048.402 underrecovery	296,048,402	105,989,914	0.2793
30	TOTAL JURISDICTIONAL FUEL COST	$7,187,394,490	105,989,914	6.7812
31	Revenue Tax Factor			1.00072
32	Fuel Factor Adjusted for Taxes	7,192,569,414		6.7861
33	GPIF ***	$5,383,572	105,989,914	0.0051
33a	WCEC 1 and 2 Jurisdictionalized Savings	($52,955,000)	16,771,151	(0.3160)
34	Fuel Factor including GPIF (Line 32 + Line 33)	7,144,997,986	105,989,914	6.4752
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			6.475

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

(a) 2007 Final True-Up under-recovery of $121,036,106 included in August -December 2008 mid-course correction factor

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2009 - DECEMBER 2009

1. Estimated/Actual over/(under) recovery (January 2008 - September 2008)		$ (296,048,402)
2. Final over/(under) recovery (January 2007 - December 2007) included in August - December 2008 mid-course correction factor	$ (121,036,106)	
3. Total over/(under) recovery to be included in the January 2008 - December 2008 projected period (Schedule E1, Line 29)		$ (296,048,402)
4. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)		105,989,914
5. True-Up Factor (Lines 3/4) c/kWh:		(0.2793)

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2008

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 (See line 75 below)	$ 341,952,079	$ 352,372,342	$ 389,720,951	$ 472,675,312	$ 567,605,752	$ 639,870,942
	b Incremental Hedging Costs	$ 41,706	$ 57,176	$ 92,341	$ 66,325	$ 50,126	$ 62,729
	c Nuclear Fuel Disposal Costs	$ 1,972,368	$ 1,762,352	$ 1,917,393	$ 1,592,404	$ 1,765,799	$ 1,976,643
	d Scherer Coal Cars Depreciation & Return	$ 246,994	$ 247,157	$ 244,955	$ 241,532	$ 238,481	$ 236,655
	e Blank Line	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	f DOE D&D Fund Payment	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2	a Fuel Cost of Power Sold (Per A6)	$ (12,447,913)	$ (9,720,557)	$ (6,131,296)	$ (2,735,840)	$ (2,711,178)	$ (5,488,875)
	b Gains from Off-System Sales	$ (4,388,836)	$ (3,042,935)	$ (1,335,798)	$ (608,278)	$ (526,160)	$ (1,123,635)
3	a Fuel Cost of Purchased Power (Per A7)	$ 21,519,165	$ 25,415,391	$ 22,085,106	$ 24,856,993	$ 26,669,255	$ 29,579,617
	b Energy Payments to Qualifying Facilities (Per A8)	$ 15,668,471	$ 17,928,683	$ 15,647,959	$ 10,333,922	$ 18,329,455	$ 18,759,926
	c Blank Line	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
4	Energy Cost of Economy Purchases (Per A9)	$ 1,176,041	$ 3,065,396	$ 8,805,031	$ 6,391,196	$ 3,243,567	$ 1,767,393
5	Total Fuel Costs & Net Power Transactions	$ 365,742,075	$ 388,085,004	$ 431,046,642	$ 512,813,567	$ 614,665,096	$ 685,641,395
6	**Adjustments to Fuel Cost**						
	a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (4,296,574)	$ (4,215,226)	$ (4,909,356)	$ (5,742,315)	$ (6,208,761)	$ (7,283,538)
	b Energy Imbalance Fuel Revenues - Account 456.225	$ (115,723)	$ (147,215)	$ (221,811)	$ (49,212)	$ (496,599)	$ (608,390)
	c Inventory Adjustments	$ (62,735)	$ 7,755	$ 23,605	$ 13,106	$ 39,710	$ (51,149)
	d Non Recoverable Oil/Tank Bottoms - Docket No. 13092	$ 0	$ 0	$ 95,927	$ 0	$ 116,256	$ 0
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 361,267,042	$ 383,730,319	$ 426,035,006	$ 507,035,146	$ 608,115,702	$ 677,698,319
B	**kWh Sales**						
1	Jurisdictional kWh Sales	$ 8,399,773,134	$ 7,454,101,518	$ 7,370,925,305	$ 7,628,218,997	$ 8,337,469,479	$ 9,759,914,795
2	Sale for Resale (excluding FKEC & CKW)	$ 655,962	$ 619,117	$ 295,189	$ 659,911	$ 642,321	$ 601,435
3	Sub-Total Sales (excluding FKEC & CKW)	$ 8,400,429,096	$ 7,454,720,635	$ 7,371,220,494	$ 7,628,878,908	$ 8,338,111,800	$ 9,760,516,230
6	**Jurisdictional % of Total Sales (B1/B3)**	99.99219%	99.99169%	99.99600%	99.99135%	99.99230%	99.99384%
C	**True-up Calculation**						
1	Juris Fuel Revenues (Net of Revenue Taxes)	$ 464,815,080	$ 409,441,562	$ 404,802,527	$ 419,941,332	$ 461,720,670	$ 544,700,995
2	**Fuel Adjustment Revenues Not Applicable to Period**						
	a Prior Period True-up (Collected)/Refunded This Period	$ (6,610,188)	$ (6,610,188)	$ (6,610,188)	$ (6,610,188)	$ (6,610,188)	$ (6,610,188)
	b GPIF, Net of Revenue Taxes (a)	$ (749,568)	$ (749,568)	$ (749,568)	$ (749,568)	$ (749,568)	$ (749,568)
	c Prior Period True-up (Collected)/Refunded This Period						
3	Jurisdictional Fuel Revenues Applicable to Period	$ 457,455,324	$ 402,081,805	$ 397,442,771	$ 412,581,575	$ 454,360,913	$ 537,341,239
4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 361,267,042	$ 383,730,319	$ 426,035,006	$ 507,035,146	$ 608,115,702	$ 677,698,319
	b Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	c RTP Incremental Fuel -100% Retail	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	d D&D Fund Payments -100% Retail	$ 0	$ 0	$ 0	$ 0	$ 0	$ 6
	e Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	$ 361,267,042	$ 383,730,319	$ 426,035,006	$ 507,035,146	$ 608,115,702	$ 677,698,319
5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.99219%	99.99169%	99.99600%	99.99135%	99.99230%	99.99384%
6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00065(b)) +(Lines C4b,c,d)	$ 361,473,633	$ 383,947,835	$ 426,294,876	$ 507,320,832	$ 608,464,122	$ 678,097,050
7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 95,981,691	$ 18,133,970	$ (28,852,105)	$ (94,739,257)	$ (154,103,209)	$ (140,755,811)
8	Interest Provision for the Month (Line D10)	$ (500,596)	$ (220,819)	$ (202,258)	$ (319,663)	$ (567,358)	$ (812,852)
9	a True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$ (79,322,258)	$ 22,769,025	$ 47,292,364	$ 24,848,189	$ (63,600,543)	$ (211,660,921)
	b Deferred True-up Beginning of Period - Over/(Under) Recovery	$ (121,036,106)	$ (121,036,106)	$ (121,036,106)	$ (121,036,106)	$ (121,036,106)	$ (121,036,106)
10	a Prior Period True-up Collected/(Refunded) This Period	$ 6,610,188	$ 6,610,188	$ 6,610,188	$ 6,610,188	$ 6,610,188	$ 6,610,188
	b Prior Period True-up Collected/(Refunded) This Period						
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (98,267,081)	$ (73,743,742)	$ (96,187,917)	$ (184,636,649)	$ (332,697,027)	$ (467,655,502)

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2008

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 (See line 75 below)	$ 634,544,249	$ 648,733,881	$ 528,186,637	$ 510,742,116	$ 382,541,692	$ 380,918,908	$ 5,849,864,861
	b Incremental Hedging Costs	$ 52,025	$ 50,005	$ 69,079	$ 50,005	$ 50,005	$ 50,005	$ 691,526
	c Nuclear Fuel Disposal Costs	$ 2,020,270	$ 1,979,510	$ 1,915,663	$ 1,760,770	$ 1,426,371	$ 2,029,287	$ 22,118,840
	d Scherer Coal Cars Depreciation & Return	$ 234,830	$ 233,004	$ 231,179	$ 229,354	$ 227,528	$ 225,703	$ 2,839,372
	e Blank Line	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	f DOE D&D Fund Payment	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2	a Fuel Cost of Power Sold (Per A6)	$ (2,420,429)	$ (13,714,835)	$ (4,194,814)	$ (5,654,222)	$ (10,319,468)	$ (21,857,614)	$ (97,397,040)
	b Gains from Off-System Sales	$ (417,096)	$ (1,476,760)	$ (365,770)	$ (488,344)	$ (1,205,725)	$ (3,712,871)	$ (18,692,207)
3	a Fuel Cost of Purchased Power (Per A7)	$ 31,104,111	$ 28,959,000	$ 27,751,773	$ 26,552,190	$ 25,135,548	$ 25,735,935	$ 315,364,084
	b Energy Payments to Qualifying Facilities (Per A8)	$ 20,536,252	$ 20,732,000	$ 19,668,000	$ 17,601,000	$ 18,493,000	$ 20,594,000	$ 214,292,668
	c Blank Line	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
4	Energy Cost of Economy Purchases (Per A9)	$ 4,977,249	$ 10,226,713	$ 16,650,132	$ 14,999,061	$ 13,785,440	$ 9,682,775	$ 94,770,014
5	Total Fuel Costs & Net Power Transactions	$ 690,631,461	$ 695,722,527	$ 589,911,879	$ 565,791,950	$ 430,134,392	$ 413,666,127	$ 6,383,852,116
6	**Adjustments to Fuel Cost**							
	a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (7,470,453)	$ (6,068,265)	$ (6,180,620)	$ (5,938,244)	$ (5,475,970)	$ (4,894,993)	$ (68,684,320)
	b Energy Imbalance Fuel Revenues - Account 456.225	$ (412,777)	$ 0	$ 0	$ 0	$ 0	$ 0	$ (2,051,728)
	c Inventory Adjustments	$ 45,546	$ 0	$ 0	$ 0	$ 0	$ 0	$ 15,838
	d Non Recoverable Oil/Tank Bottoms - Docket No. 13092	$ 73,212	$ 0	$ 0	$ 0	$ 0	$ 0	$ 285,395
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 682,866,989	$ 689,654,262	$ 583,731,259	$ 559,853,706	$ 424,658,416	$ 408,771,134	$ 6,313,417,301
B	**kWh Sales**							
1	Jurisdictional kWh Sales	$ 9,757,483,937	$ 10,421,048,000	$ 10,134,184,000	$ 9,650,713,000	$ 8,624,742,000	$ 8,314,199,000	$ 105,852,773,165
2	Sale for Resale (excluding FKEC & CKW)	$ 615,667	$ 520,000	$ 526,000	$ 489,000	$ 427,000	$ 517,000	$ 6,568,602
3	Sub-Total Sales (excluding FKEC & CKW)	$ 9,758,099,604	$ 10,421,568,000	$ 10,134,710,000	$ 9,651,202,000	$ 8,625,169,000	$ 8,314,716,000	$ 105,859,341,767
6	**Jurisdictional % of Total Sales (B1/B3)**	99.99369%	99.99501%	99.99481%	99.99493%	99.99505%	99.99378%	99.99379%
C	**True-up Calculation**							
1	Juris Fuel Revenues (Net of Revenue Taxes)	$ 544,705,015	$ 660,772,391	$ 642,584,355	$ 611,927,861	$ 546,872,941	$ 527,188,881	$ 6,239,473,610
2	**Fuel Adjustment Revenues Not Applicable to Period**							
	a Prior Period True-up (Collected)/Refunded This Period	$ (6,610,188)	$ (6,610,188)	$ (6,610,188)	$ (6,610,188)	$ (6,610,188)	$ (6,610,188)	$ (79,322,258)
	b GPIF, Net of Revenue Taxes (a)	$ (749,568)	$ (749,568)	$ (749,568)	$ (749,568)	$ (749,568)	$ (749,568)	$ (8,994,819)
	c Prior Period True-up (Collected)/Refunded This Period		$ (24,207,221)	$ (24,207,221)	$ (24,207,221)	$ (24,207,221)	$ (24,207,221)	$ (121,036,106)
3	Jurisdictional Fuel Revenues Applicable to Period	$ 537,345,259	$ 629,205,413	$ 611,017,378	$ 580,360,884	$ 515,305,963	$ 495,621,903	$ 6,030,120,427
4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 682,866,989	$ 689,654,262	$ 583,731,259	$ 559,853,706	$ 424,658,416	$ 408,771,134	$ 6,313,417,301
	b Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	0
	c RTP Incremental Fuel -100% Retail	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	0
	d D&D Fund Payments -100% Retail	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	0
	e Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	$ 682,866,989	$ 689,654,262	$ 583,731,259	$ 559,853,706	$ 424,658,416	0 $ 408,771,134	$ 6,313,417,301
5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.99369%	99.99501%	99.99481%	99.99493%	99.99505%	99.99378%	99.99379%
6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00065(b)) +(Lines C4b,c,d)	$ 683,267,735	$ 690,068,101	$ 584,080,369	$ 560,189,208	$ 424,913,410	$ 409,011,393	$ 6,317,128,564
7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (145,922,477)	$ (60,862,688)	$ 26,937,009	$ 20,171,676	$ 90,392,554	$ 86,610,510	$ (287,008,137)
8	Interest Provision for the Month (Line D10)	$ (1,094,772)	$ (1,266,919)	$ (1,241,325)	$ (1,133,295)	$ (960,533)	$ (719,875)	$ (9,040,265)
9	a True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$ (346,619,396)	$ (487,026,457)	$ (518,338,655)	$ (461,825,561)	$ (411,969,771)	$ (291,720,340)	$ (79,322,258)
	b Deferred True-up Beginning of Period - Over/(Under) Recovery	$ (121,036,106)	$ (121,036,106)	$ (121,036,106)	$ (121,036,106)	$ (121,036,106)	$ (121,036,106)	$ (121,036,106)
10	a Prior Period True-up Collected/(Refunded) This Period	$ 6,610,188	$ 6,610,188	$ 6,610,188	$ 6,610,188	$ 6,610,188	$ 6,610,188	$ 79,322,258
	b Prior Period True-up Collected/(Refunded) This Period		$ 24,207,221	$ 24,207,221	$ 24,207,221	$ 24,207,221	$ 24,207,221	$ 121,036,106
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (608,062,563)	$ (639,374,761)	$ (582,861,667)	$ (533,005,877)	$ (412,756,446)	$ (296,048,402)	$ (296,048,402)

SCHEDULE E - 1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE - UP FACTOR FLORIDA POWER AND LIGHT COMPANY FOR THE PERIOD: JANUARY 2009 - DECEMBER 2009

1. TOTAL AMOUNT OF ADJUSTMENTS:	301,431,974
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$5,383,572
B. TRUE-UP (OVER)/UNDER RECOVERED	$ 296,048,402
2. TOTAL JURISDICTIONAL SALES (MWH)	105,989,914
3. ADJUSTMENT FACTORS c/kWh:	0.2844
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0051
B. TRUE-UP FACTOR	0.2793

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D
Page 1 of 2

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2009 - MAY 2009

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	31.07	34.90
OFF PEAK	68.93	65.10
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$6,896,364,025	$2,406,914,221	$4,489,449,804
2	MWH SALES	106,126,486	32,978,092	73,148,394
3	COST PER KWH SOLD	6.4982	7.2985	6.1375
4	JURISDICTIONAL LOSS FACTOR	1.00056	1.00056	1.00056
5	JURISDICTIONAL FUEL FACTOR	6.5019	7.3026	6.1409
6	TRUE-UP	0.2793	0.2793	0.2793
7				
8	TOTAL	6.7812	7.5819	6.4202
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	6.7861	7.5874	6.4248
11	GPIF	0.0051	0.0051	0.0051
11a	FUEL SAVINGS DUE TO WCEC 1&2	(0.0469)	(0.0469)	(0.0469)
12	RECOVERY FACTOR including GPIF	6.7443	7.5456	6.3830
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	6.744	7.546	6.383

HOURS:	ON-PEAK	24.74 %
	OFF-PEAK	75.26 %

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JUNE 2009 - OCTOBER 2009

NET ENERGY FOR LOAD (%)

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	31.07	34.90
OFF PEAK	68.93	65.10
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$6,896,364,025	$2,406,914,221	$4,489,449,804
2	MWH SALES	106,126,486	32,978,092	73,148,394
3	COST PER KWH SOLD	6.4982	7.2985	6.1375
4	JURISDICTIONAL LOSS FACTOR	1.00056	1.00056	1.00056
5	JURISDICTIONAL FUEL FACTOR	6.5019	7.3026	6.1409
6	TRUE-UP	0.2793	0.2793	0.2793
7				
8	TOTAL	6.7812	7.5819	6.4202
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	6.7861	7.5874	6.4248
11	GPIF	0.0051	0.0051	0.0051
11a	FUEL SAVINGS DUE TO WCEC 1&2	(0.1880)	(0.1880)	(0.1880)
12	RECOVERY FACTOR including GPIF	6.6032	7.4045	6.2419
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	6.603	7.405	6.242

HOURS:		
	ON-PEAK	24.74 %
	OFF-PEAK	75.26 %

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

NOVEMBER 2009 - DECEMBER 2009

NET ENERGY FOR LOAD (%)

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	31.07	34.90
OFF PEAK	68.93	65.10
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$6,896,364,025	$2,406,914,221	$4,489,449,804
2	MWH SALES	106,126,486	32,978,092	73,148,394
3	COST PER KWH SOLD	6.4982	7.2985	6.1375
4	JURISDICTIONAL LOSS FACTOR	1.00056	1.00056	1.00056
5	JURISDICTIONAL FUEL FACTOR	6.5019	7.3026	6.1409
6	TRUE-UP	0.2793	0.2793	0.2793
7				
8	TOTAL	6.7812	7.5819	6.4202
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	6.7861	7.5874	6.4248
11	GPIF	0.0051	0.0051	0.0051
11a	FUEL SAVINGS DUE TO WCEC 1&2	(0.3160)	(0.3160)	(0.3160)
12	RECOVERY FACTOR including GPIF	6.4752	7.2765	6.1139
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	6.475	7.277	6.114

HOURS:		
	ON-PEAK	24.74 %
	OFF-PEAK	75.26 %

FLORIDA POWER & LIGHT COMPANY

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

ON PEAK: JUNE 2009 THROUGH SEPTEMBER 2009 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	24.00	26.92
OFF PEAK	76.00	73.08
	100.00	100.00

SDTR FUEL RECOVERY CALCULATION

	TOTAL	ON-PEAK	OFF-PEAK
1 TOTAL FUEL & NET POWER TRANS	$6,896,364,025	$1,856,207,757	$5,040,156,268
2 MWH SALES	106,126,486	25,470,697	80,655,789
3 COST PER KWH SOLD	6.4982	7.2876	6.2490
4 JURISDICTIONAL LOSS FACTOR	1.00056	1.00056	1.00056
5 JURISDICTIONAL FUEL FACTOR	6.5019	7.2917	6.2525
6 TRUE-UP	0.2793	0.2793	0.2793
7			
8 TOTAL	6.7812	7.5710	6.5318
9 REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10 SDTR RECOVERY FACTOR	6.7861	7.5765	6.5365
11 GPIF	0.0051	0.0051	0.0051
11a FUEL SAVINGS DUE TO WCEC 1 & 2	(0.1880)	(0.1880)	(0.1880)
12 SDTR RECOVERY FACTOR including GPIF	6.6032	7.3936	6.3536
13 SDTR RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	6.603	7.394	6.354

HOURS:	ON-PEAK	19.77 %
	OFF-PEAK	80.23 %

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 2009 - MAY 2009

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh		6.744	1.00183	6.413
	all additional kWh		6.744	1.00183	7.413
A	GS-1, SL-2, GSCU-1, WIES-1		6.744	1.00183	6.757
A-1*	SL-1, OL-1, PL-1		6.569	1.00183	6.581
B	GSD-1		6.744	1.00178	6.756
C	GSLD-1 & CS-1		6.744	1.00078	6.750
D	GSLD-2, CS-2, OS-2 & MET		6.744	0.99318	6.698
E	GSLD-3 & CS-3		6.744	0.95923	6.469
A	RST-1, GST-1	ON-PEAK	7.546	1.00183	7.559
		OFF-PEAK	6.383	1.00183	6.395
B	GSDT-1, CILC-1(G),	ON-PEAK	7.546	1.00177	7.559
	HLFT-1 (21-499 kW)	OFF-PEAK	6.383	1.00177	6.394
C	GSLDT-1, CST-1,	ON-PEAK	7.546	1.00093	7.553
	HLFT-2 (500-1,999 kW)	OFF-PEAK	6.383	1.00093	6.389
D	GSLDT-2, CST-2,	ON-PEAK	7.546	0.99481	7.506
	HLFT-3 (2,000+)	OFF-PEAK	6.383	0.99481	6.350
E	GSLDT-3,CST-3,	ON-PEAK	7.546	0.95923	7.238
	CILC -1(T) & ISST-1(T)	OFF-PEAK	6.383	0.95923	6.123
F	CILC -1(D) &	ON-PEAK	7.546	0.99371	7.498
	ISST-1(D)	OFF-PEAK	6.383	0.99371	6.343

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

FLORIDA POWER & LIGHT COMPANY

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

JUNE 2009 - OCTOBER 2009

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh		6.603	1.00183	6.272
	all additional kWh		6.603	1.00183	7.272
A	GS-1, SL-2, GSCU-1, WIES-1		6.603	1.00183	6.615
A-1*	SL-1, OL-1, PL-1		6.428	1.00183	6.440
B	GSD-1		6.603	1.00178	6.615
C	GSLD-1 & CS-1		6.603	1.00078	6.608
D	GSLD-2, CS-2, OS-2 & MET		6.603	0.99318	6.558
E	GSLD-3 & CS-3		6.603	0.95923	6.334
A	RST-1, GST-1	ON-PEAK	7.405	1.00183	7.418
		OFF-PEAK	6.242	1.00183	6.253
B	GSDT-1, CILC-1(G),	ON-PEAK	7.405	1.00177	7.418
	HLFT-1 (21-499 kW)	OFF-PEAK	6.242	1.00177	6.253
C	GSLDT-1, CST-1,	ON-PEAK	7.405	1.00093	7.411
	HLFT-2 (500-1,999 kW)	OFF-PEAK	6.242	1.00093	6.248
D	GSLDT-2, CST-2,	ON-PEAK	7.405	0.99481	7.366
	HLFT-3 (2,000+)	OFF-PEAK	6.242	0.99481	6.209
E	GSLDT-3, CST-3,	ON-PEAK	7.405	0.95923	7.103
	CILC -1(T) & ISST-1(T)	OFF-PEAK	6.242	0.95923	5.987
F	CILC -1(D) &	ON-PEAK	7.405	0.99371	7.358
	ISST-1(D)	OFF-PEAK	6.242	0.99371	6.203

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

FLORIDA POWER & LIGHT COMPANY

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

NOVEMBER 2009 - DECEMBER 2009

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh		6.475	1.00183	6.144
	all additional kWh		6.475	1.00183	7.144
A	GS-1, SL-2, GSCU-1, WIES-1		6.475	1.00183	6.487
A-1*	SL-1, OL-1, PL-1		6.300	1.00183	6.312
B	GSD-1		6.475	1.00178	6.487
C	GSLD-1 & CS-1		6.475	1.00078	6.480
D	GSLD-2, CS-2, OS-2 & MET		6.475	0.99318	6.431
E	GSLD-3 & CS-3		6.475	0.95923	6.211
A	RST-1, GST-1	ON-PEAK	7.277	1.00183	7.290
		OFF-PEAK	6.114	1.00183	6.125
B	GSDT-1, CILC-1(G),	ON-PEAK	7.277	1.00177	7.289
	HLFT-1 (21-499 kW)	OFF-PEAK	6.114	1.00177	6.125
C	GSLDT-1, CST-1,	ON-PEAK	7.277	1.00093	7.283
	HLFT-2 (500-1,999 kW)	OFF-PEAK	6.114	1.00093	6.120
D	GSLDT-2, CST-2,	ON-PEAK	7.277	0.99481	7.239
	HLFT-3 (2,000+)	OFF-PEAK	6.114	0.99481	6.082
E	GSLDT-3,CST-3,	ON-PEAK	7.277	0.95923	6.980
	CILC -1(T)	OFF-PEAK	6.114	0.95923	5.865
	& ISST-1(T)				
F	CILC -1(D) &	ON-PEAK	7.277	0.99371	7.231
	ISST-1(D)	OFF-PEAK	6.114	0.99371	6.075

* 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 2009 THROUGH SEPTEMBER 2009 - 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	7.394	1.00178	7.407
		OFF-PEAK	6.354	1.00178	6.365
C	GSLD(T)-1	ON-PEAK	7.394	1.00084	7.400
		OFF-PEAK	6.354	1.00084	6.359
D	GSLD(T)-2	ON-PEAK	7.394	0.99488	7.356
		OFF-PEAK	6.354	0.99488	6.321

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

Florida Power & Light Company
2007 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	55,029,412	1.06901375	58,827,198	0.935442	3,797,786	1.00183
2								
3	CILC-1D	P	1,121,774	1.04443473	1,171,619	0.957456	49,846	
4	CILC-1D	S	2,058,416	1.06901375	2,200,475	0.935442	142,059	
5	CILC-1D Total		3,180,190	1.06034380	3,372,094	0.943090	191,905	0.99371
6								
7	CILC-1G	P	0	1.04443473	0	0.000000	0	
8	CILC-1G	S	216,344	1.06901375	231,274	0.935442	14,931	
9	CILC-1G Total		216,344	1.06901375	231,274	0.935442	14,931	1.00183
10								
11	CILC-1T	T	1,483,223	1.02355239	1,518,156	0.976990	34,933	0.95923
12								
13	CS-1	P	25,688	1.04443473	26,830	0.957456	1,141	
14	CS-1	S	167,804	1.06901375	179,385	0.935442	11,581	
15	CS-1 Total		193,493	1.06575059	206,215	0.938306	12,722	0.99878
16								
17	CS-2	P	31,619	1.04443473	33,024	0.957456	1,405	
18	CS-2	S	53,882	1.06901375	57,600	0.935442	3,719	
19	CS-2 Total		85,501	1.05992416	90,624	0.943464	5,124	0.99332
20								
21	CS-3	T	13,073	1.02355239	13,380	0.976990	308	0.95923
22								
23	GS-1	S	6,177,278	1.06901375	6,603,595	0.935442	426,317	1.00183
24								
25	GSCU-1	S	53,438	1.06901375	57,126	0.935442	3,688	1.00183
26								
27	GSD-1	P	53,541	1.04443473	55,920	0.957456	2,379	
28	GSD-1	S	23,306,452	1.06901375	24,914,918	0.935442	1,608,466	
29	GSD-1 Total		23,359,993	1.06895742	24,970,838	0.935491	1,610,845	1.00178
30								
31	GSLD-1	P	246,478	1.04443473	257,430	0.957456	10,952	
32	GSLD-1	S	5,476,249	1.06901375	5,854,186	0.935442	377,937	
33	GSLD-1 Total		5,722,727	1.06795513	6,111,616	0.936369	388,889	1.00084
34								
35	GSLD-2	P	277,986	1.04443473	290,338	0.957456	12,352	
36	GSLD-2	S	642,906	1.06901375	687,275	0.935442	44,369	
37	GSLD-2 Total		920,891	1.06159418	977,613	0.941980	56,722	0.99488
38								
39	GSLD-3	T	246,708	1.02355239	252,519	0.976990	5,811	0.95923
40								
41	HLFT-1	P	11,578	1.04443473	12,092	0.957456	514	
42	HLFT-1	S	1,185,975	1.06901375	1,267,824	0.935442	81,849	
43	HLFT-1 Total		1,197,553	1.06877612	1,279,916	0.935650	82,363	1.00161
44								
45	HLFT-2	P	154,905	1.04443473	161,788	0.957456	6,883	
46	HLFT-2	S	4,824,038	1.06901375	5,156,963	0.935442	332,925	
47	HLFT-2 Total		4,978,943	1.06824905	5,318,751	0.936111	339,808	1.00112
48								
49	HLFT-3	P	316,839	1.04443473	330,918	0.957456	14,079	
50	HLFT-3	S	729,660	1.06901375	780,016	0.935442	50,357	
51	HLFT-3 Total		1,046,499	1.06157218	1,110,934	0.941999	64,435	0.99486
52								
53	MET	P	91,321	1.04443473	95,378	0.957456	4,058	0.97880
54								

Florida Power & Light Company

2007 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
55	OL-1	S	107,079	1.06901375	114,469	0.935442	7,390	1.00183
56								
57	OS-2	P	18,373	1.04443473	19,190	0.957456	816	
58	OS-2	S	-	1.06901375	-	0.000000	-	
59	OS-2 Total		18,373	1.04443473	19,190	0.957456	816	0.97880
60								
61	STDR-1	P	450	1.04443473	470	0.957456	20	
62	STDR-1	S	215,749	1.06901375	230,638	0.935442	14,890	
63	STDR-1 Total		216,199	1.06896258	231,108	0.935486	14,910	1.00179
64								
65	STDR-2	P	48,889	1.04443473	51,061	0.957456	2,172	
66	STDR-2	S	200,515	1.06901375	214,353	0.935442	13,838	
67	STDR-2 Total		249,403	1.06419570	265,414	0.939677	16,011	0.99732
68								
69	STDR-3	P	32,334	1.04443473	33,770	0.957456	1,437	
70	STDR-3	S	34,066	1.06901375	36,417	0.935442	2,351	
71	STDR-3 Total		66,399	1.05704488	70,187	0.946034	3,788	0.99062
72								
73	SL-1	S	473,449	1.06901375	506,123	0.935442	32,674	1.00183
74								
75	SL-2	S	55,336	1.06901375	59,155	0.935442	3,819	1.00183
76								
77	SST-1D	P	5,346	1.04443473	5,584	0.957456	238	
78	SST-1D	S	0	1.06901375	0	0.000000	0	
79	SST-1D Total		5,346	1.04443473	5,584	0.957456	238	0.97880
80								
81	SST-1T	T	86,461	1.02355239	88,497	0.976990	2,036	0.95923
82								
83	**Rate Class Groups -**							
84								
85	CILC-1D / CILC-1G		3,396,533	1.06089603	3,603,369	0.942599	206,835	0.99423
86								
87	GSDT-1 / HLFT-1		24,557,546	1.06894858	26,250,754	0.935499	1,693,208	1.00177
88								
89	GSDT-1, CILC-1G & HLFT-1		24,773,890	1.06894915	26,482,028	0.935498	1,708,139	1.00177
90								
91	GSLD-1 / CS-1		5,916,220	1.06788303	6,317,831	0.936432	401,611	1.00078
92								
93	GSLDT-1, CST-1 & HLFT-2		10,895,163	1.06805030	11,636,582	0.936285	741,419	1.00093
94								
95	GSLD-2 / CS-2		1,006,392	1.06145230	1,068,237	0.942105	61,845	0.99475
96								
97	GSLDT-2, CST-2 & HLFT-3		2,052,891	1.06151341	2,179,171	0.942051	126,280	0.99481
98								
99	GSLD-2, CS-2, OS-2 & MET		1,116,086	1.05977974	1,182,805	0.943592	66,719	0.99318
100								
101	GSLD-3 / CS-3		259,781	1.02355239	265,899	0.976990	6,118	0.95923
102								
103	GSLDT-3, CST-3 & CILC-1T		1,743,003	1.02355239	1,784,055	0.976990	41,052	0.95923
104								
105	OL-1 / SL-1		580,528	1.06901375	620,593	0.935442	40,064	1.00183
106								
107	SL-2 / GSCU-1		108,774	1.06901375	116,281	0.935442	7,507	1.00183
108								

Florida Power & Light Company

2007 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
109	Total FPSC		105,274,631	1.06765472	112,396,957	0.936632	7,122,325	1.00056
110								
111	Total FERC Sales		1,454,667	1.02355239	1,488,928	0.976990	34,261	
112								
113	Total Company		106,729,298	1.06705362	113,885,884	0.937160	7,156,586	
114								
115	Company Use		129,737	1.06901375	138,691	0.935442	8,954	
116								
117	Total FPL		106,859,035	1.06705600	114,024,575	0.937158	7,165,540	1.00000
118								
119	**Summary of Sales by Voltage:**							
120								
121	Transmission		3,284,131	1.02355239	3,361,480	0.976990	77,349	
122								
123	Primary		2,437,120	1.04443473	2,545,413	0.957456	108,293	
124								
125	Secondary		101,008,047	1.06901375	107,978,991	0.935442	6,970,944	
126								
127	Total		106,729,298	1.06705362	113,885,884	0.937160	7,156,586	
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 2009 - MAY 2009

SCHEDULE E2

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$407,161,518	$360,159,134	$436,696,407	$459,222,843	$569,090,084	$593,429,664	$2,825,759,649	A1
1a	NUCLEAR FUEL DISPOSAL	2,029,287	1,832,904	1,546,366	1,793,384	1,498,625	1,900,150	10,600,716	1a
1b	COAL CAR INVESTMENT	227,871	226,008	224,145	222,283	220,420	218,558	1,339,285	1b
1c	ADJUSTMENT FOR WEST COUNTY 1 & 2	13,737,500	13,737,500	13,737,500	13,737,500	13,737,500	13,737,500	82,425,000	1c
1d	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1d
1e	INCREMENTAL HEDGING COSTS	51,942	51,942	88,438	53,520	53,520	53,520	352,882	1e
2	FUEL COST OF POWER SOLD	(17,641,350)	(14,113,749)	(12,887,790)	(9,452,595)	(7,127,668)	(7,054,681)	(68,277,834)	2
2a	GAIN ON ECONOMY SALES	(3,434,011)	(3,547,385)	(1,767,209)	(912,002)	(765,451)	(811,740)	(11,237,798)	2a
3	FUEL COST OF PURCHASED POWER	29,345,542	27,880,979	27,299,381	26,809,590	29,430,031	27,532,613	168,298,137	3
3a	QUALIFYING FACILITIES	20,800,000	17,852,000	21,403,000	9,704,000	21,327,100	21,154,893	112,240,993	3a
4	ENERGY COST OF ECONOMY PURCHASES	5,549,380	2,896,743	8,382,845	11,013,710	13,743,720	7,077,431	48,663,828	4
4a	FUEL COST OF SALES TO FKEC / CKW	(5,540,213)	(5,576,844)	(5,474,473)	(5,821,752)	(6,168,880)	(6,637,259)	(35,219,419)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$452,287,465	$401,399,232	$489,248,610	$506,370,481	$635,039,001	$650,600,650	$3,134,945,438	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,394,330	7,536,675	7,664,649	7,603,911	8,491,409	9,526,718	49,217,692	6
7	COST PER KWH SOLD (¢/KWH)	5.3880	5.3259	6.3832	6.6593	7.4786	6.8292	6.3695	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	7a
7b	JURISDICTIONAL COST (¢/KWH)	5.3910	5.3289	6.3868	6.6631	7.4828	6.8330	6.3731	7b
9	TRUE-UP (¢/KWH)	0.2941	0.3276	0.3221	0.3247	0.2907	0.2593	0.3010	9
10	TOTAL	5.6851	5.6565	6.7089	6.9878	7.7735	7.0923	6.6741	10
11	REVENUE TAX FACTOR 0.00072	0.0041	0.0041	0.0048	0.0050	0.0056	0.0051	0.0048	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	5.6892	5.6606	6.7137	6.9928	7.7791	7.0974	6.6789	12
13	GPIF (¢/KWH)	0.0053	0.0060	0.0059	0.0059	0.0053	0.0047	0.0055	13
13a	JURISDICTIONALIZED SAVINGS-WCEC 1&2	(0.0444)	(0.0494)	(0.0486)	(0.0490)	(0.0439)	0.0000	(0.0469)	13a
14	RECOVERY FACTOR including GPIF	5.6501	5.6172	6.6710	6.9497	7.7405	7.1021	6.6375	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	5.650	5.617	6.671	6.950	7.741	7.102	6.638	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2009 - MAY 2009

LINE NO.		(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$683,941,154	$692,871,394	$639,279,703	$569,416,842	$417,071,062	$385,933,690	$6,214,273,493	A1
1a	NUCLEAR FUEL DISPOSAL	1,979,519	1,979,519	1,915,663	1,874,120	1,496,482	1,982,553	$21,828,572	1a
1b	COAL CAR INVESTMENT	216,695	214,833	212,970	211,108	209,245	207,383	$2,611,519	1b
1c	ADJUSTMENT FOR WEST COUNTY 1 & 2	13,737,500	13,737,500	13,737,500	13,737,500	13,737,500	13,737,500	$164,850,000	1c
1d	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	$0 $0	1d
1e	INCREMENTAL HEDGING COSTS	53,520	74,028	53,520	53,520	53,520	53,520	$694,510	1e
2	FUEL COST OF POWER SOLD	(6,334,043)	(14,231,863)	(4,250,289)	(5,472,641)	(6,711,083)	(10,812,349)	($116,090,101)	2
2a	GAIN ON ECONOMY SALES	(634,111)	(1,653,071)	(353,664)	(478,138)	(1,204,331)	(2,886,686)	($18,447,799)	2a
3	FUEL COST OF PURCHASED POWER	31,089,900	31,131,591	29,712,418	30,849,652	30,106,446	30,141,600	$351,329,743	3
3a	QUALIFYING FACILITIES	22,820,000	23,183,000	21,679,000	19,694,000	15,956,000	20,380,000	$235,952,993	3a
4	ENERGY COST OF ECONOMY PURCHASES	9,944,038	8,946,982	17,323,797	17,029,993	7,883,060	6,490,247	$116,281,945	4
4a	FUEL COST OF SALES TO FKEC / CKW	(7,212,596)	(7,338,510)	(7,468,260)	(7,252,161)	(6,511,495)	(5,918,406)	($76,920,848)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$749,601,576	$748,915,402	$711,842,357	$639,663,794	$472,086,406	$439,309,052	$6,896,364,025	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	10,261,393	10,257,659	10,640,511	8,965,734	8,658,115	8,125,387	106,126,486	6
7	COST PER KWH SOLD (¢/KWH)	7.3051	7.3010	6.6899	7.1345	5.4525	5.4066	6.4982	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	7a
7b	JURISDICTIONAL COST (¢/KWH)	7.3092	7.3051	6.6937	7.1385	5.4556	5.4097	6.5019	7b
9	TRUE-UP (¢/KWH)	0.2409	0.2410	0.2323	0.2758	0.2852	0.3038	0.2793	9
10	TOTAL	7.5501	7.5461	6.9260	7.4143	5.7408	5.7135	6.7812	10
11	REVENUE TAX FACTOR 0.00072	0.0054	0.0054	0.0050	0.0053	0.0041	0.0041	0.0049	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	7.5555	7.5515	6.9310	7.4196	5.7449	5.7176	6.7861	12
13	GPIF (¢/KWH)	0.0044	0.0044	0.0042	0.0050	0.0052	0.0055	0.0051	13
13a	JURISDICTIONALIZED SAVINGS-WCEC 1&2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(0.0469)	13a
14	RECOVERY FACTOR including GPIF	7.5599	7.5559	6.9352	7.4246	5.7501	5.7231	6.7443	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	7.560	7.556	6.935	7.425	5.750	5.723	6.744	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JUNE 2009 - OCTOBER 2009

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$407,161,518	$360,159,134	$436,696,407	$459,222,843	$569,090,084	$593,429,664	$2,825,759,649	A1
1a	NUCLEAR FUEL DISPOSAL	2,029,287	1,832,904	1,546,366	1,793,384	1,498,625	1,900,150	10,600,716	1a
1b	COAL CAR INVESTMENT	227,871	226,008	224,145	222,283	220,420	218,558	1,339,285	1b
1c	ADJUSTMENT FOR WEST COUNTY 1 & 2	13,737,500	13,737,500	13,737,500	13,737,500	13,737,500	13,737,500	82,425,000	1c
1d	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1d
1e	INCREMENTAL HEDGING COSTS	51,942	51,942	88,438	53,520	53,520	53,520	352,882	1e
2	FUEL COST OF POWER SOLD	(17,641,350)	(14,113,749)	(12,887,790)	(9,452,595)	(7,127,668)	(7,054,681)	(68,277,834)	2
2a	GAIN ON ECONOMY SALES	(3,434,011)	(3,547,385)	(1,767,209)	(912,002)	(765,451)	(811,740)	(11,237,798)	2a
3	FUEL COST OF PURCHASED POWER	29,345,542	27,880,979	27,299,381	26,809,590	29,430,031	27,532,613	168,298,137	3
3a	QUALIFYING FACILITIES	20,800,000	17,852,000	21,403,000	9,704,000	21,327,100	21,154,893	112,240,993	3a
4	ENERGY COST OF ECONOMY PURCHASES	5,549,380	2,896,743	8,382,845	11,013,710	13,743,720	7,077,431	48,663,828	4
4a	FUEL COST OF SALES TO FKEC / CKW	(5,540,213)	(5,576,844)	(5,474,473)	(5,821,752)	(6,168,880)	(6,637,259)	(35,219,419)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$452,287,465	$401,399,232	$489,248,610	$506,370,481	$635,039,001	$650,600,650	$3,134,945,438	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,394,330	7,536,675	7,664,649	7,603,911	8,491,409	9,526,718	49,217,692	6
7	COST PER KWH SOLD (¢/KWH)	5.3880	5.3259	6.3832	6.6593	7.4786	6.8292	6.3695	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	7a
7b	JURISDICTIONAL COST (¢/KWH)	5.3910	5.3289	6.3868	6.6631	7.4828	6.8330	6.3731	7b
9	TRUE-UP (¢/KWH)	0.2941	0.3276	0.3221	0.3247	0.2907	0.2593	0.3010	9
10	TOTAL	5.6851	5.6565	6.7089	6.9878	7.7735	7.0923	6.6741	10
11	REVENUE TAX FACTOR 0.00072	0.0041	0.0041	0.0048	0.0050	0.0056	0.0051	0.0048	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	5.6892	5.6606	6.7137	6.9928	7.7791	7.0974	6.6789	12
13	GPIF (¢/KWH)	0.0053	0.0060	0.0059	0.0059	0.0053	0.0047	0.0055	13
13a	JURISDICTIONALIZED SAVINGS-WCEC 1&2	0.0000	0.0000	0.0000	0.0000	0.0000	(0.1958)	(0.1958)	13a
14	RECOVERY FACTOR including GPIF	5.6945	5.6666	6.7196	6.9987	7.7844	6.9063	6.4886	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	5.695	5.667	6.720	6.999	7.784	6.906	6.489	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JUNE 2009 - OCTOBER 2009

LINE NO.		(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$683,941,154	$692,871,394	$639,279,703	$569,416,842	$417,071,062	$385,933,690	$6,214,273,493	A1
1a	NUCLEAR FUEL DISPOSAL	1,979,519	1,979,519	1,915,663	1,874,120	1,496,482	1,982,553	$21,828,572	1a
1b	COAL CAR INVESTMENT	216,695	214,833	212,970	211,108	209,245	207,383	$2,611,519	1b
1c	*ADJUSTMENT FOR WEST COUNTY 1 & 2*	*13,737,500*	*13,737,500*	*13,737,500*	*13,737,500*	*13,737,500*	*13,737,500*	$164,850,000	
1c	DOE DECONTAMINATION AND	0	0	0	0	0	0	$0	1c
	DECOMMISSIONING COSTS							$0	
1d	INCREMENTAL HEDGING COSTS	53,520	74,028	53,520	53,520	53,520	53,520	$694,510	1d
2	FUEL COST OF POWER SOLD	(6,334,043)	(14,231,863)	(4,250,289)	(5,472,641)	(6,711,083)	(10,812,349)	($116,090,101)	2
2a	GAIN ON ECONOMY SALES	(634,111)	(1,653,071)	(353,664)	(478,138)	(1,204,331)	(2,886,686)	($18,447,799)	2a
3	FUEL COST OF PURCHASED POWER	31,089,900	31,131,591	29,712,418	30,849,652	30,106,446	30,141,600	$351,329,743	3
3a	QUALIFYING FACILITIES	22,820,000	23,183,000	21,679,000	19,694,000	15,956,000	20,380,000	$235,952,993	3a
4	ENERGY COST OF ECONOMY PURCHASES	9,944,038	8,946,982	17,323,797	17,029,993	7,883,060	6,490,247	$116,281,945	4
4a	FUEL COST OF SALES TO FKEC / CKW	(7,212,596)	(7,338,510)	(7,468,260)	(7,252,161)	(6,511,495)	(5,918,406)	($76,920,848)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$749,601,576	$748,915,402	$711,842,357	$639,663,794	$472,086,406	$439,309,052	$6,896,364,025	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	10,261,393	10,257,659	10,640,511	8,965,734	8,658,115	8,125,387	106,126,486	6
7	COST PER KWH SOLD (¢/KWH)	7.3051	7.3010	6.6899	7.1345	5.4525	5.4066	6.4982	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	7a
7b	JURISDICTIONAL COST (¢/KWH)	7.3092	7.3051	6.6937	7.1385	5.4556	5.4097	6.5019	7b
9	TRUE-UP (¢/KWH)	0.2409	0.2410	0.2323	0.2758	0.2852	0.3038	0.2793	9
10	TOTAL	7.5501	7.5461	6.9260	7.4143	5.7408	5.7135	6.7812	10
11	REVENUE TAX FACTOR 0.00072	0.0054	0.0054	0.0050	0.0053	0.0041	0.0041	0.0049	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	7.5555	7.5515	6.9310	7.4196	5.7449	5.7176	6.7861	12
13	GPIF (¢/KWH)	0.0044	0.0044	0.0042	0.0050	0.0052	0.0055	0.0051	13
13a	JURISDICTIONALIZED SAVINGS-WCEC 1&2	(0.1819)	(0.1820)	(0.1754)	(0.2083)	0.0000	0.0000	(0.1880)	
14	RECOVERY FACTOR including GPIF	7.3780	7.3739	6.7598	7.2163	5.7501	5.7231	6.6032	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	7.378	7.374	6.760	7.216	5.750	5.723	6.603	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD NOVEMBER 2009 - DECEMBER 2009

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$407,161,518	$360,159,134	$436,696,407	$459,222,843	$569,090,084	$593,429,664	$2,825,759,649	A1
1a	NUCLEAR FUEL DISPOSAL	2,029,287	1,832,904	1,546,366	1,793,384	1,498,625	1,900,150	10,600,716	1a
1b	COAL CAR INVESTMENT	227,871	226,008	224,145	222,283	220,420	218,558	1,339,285	1b
1c	ADJUSTMENT FOR WEST COUNTY 1 & 2	13,737,500	13,737,500	13,737,500	13,737,500	13,737,500	13,737,500	82,425,000	1c
1d	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1d
1e	INCREMENTAL HEDGING COSTS	51,942	51,942	88,438	53,520	53,520	53,520	352,882	1e
2	FUEL COST OF POWER SOLD	(17,641,350)	(14,113,749)	(12,887,790)	(9,452,595)	(7,127,668)	(7,054,681)	(68,277,834)	2
2a	GAIN ON ECONOMY SALES	(3,434,011)	(3,547,385)	(1,767,209)	(912,002)	(765,451)	(811,740)	(11,237,798)	2a
3	FUEL COST OF PURCHASED POWER	29,345,542	27,880,979	27,299,381	26,809,590	29,430,031	27,532,613	168,298,137	3
3a	QUALIFYING FACILITIES	20,800,000	17,852,000	21,403,000	9,704,000	21,327,100	21,154,893	112,240,993	3a
4	ENERGY COST OF ECONOMY PURCHASES	5,549,380	2,896,743	8,382,845	11,013,710	13,743,720	7,077,431	48,663,828	4
4a	FUEL COST OF SALES TO FKEC / CKW	(5,540,213)	(5,576,844)	(5,474,473)	(5,821,752)	(6,168,880)	(6,637,259)	(35,219,419)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$452,287,465	$401,399,232	$489,248,610	$506,370,481	$635,039,001	$650,600,650	$3,134,945,438	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,394,330	7,536,675	7,664,649	7,603,911	8,491,409	9,526,718	49,217,692	6
7	COST PER KWH SOLD (¢/KWH)	5.3880	5.3259	6.3832	6.6593	7.4786	6.8292	6.3695	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	7a
7b	JURISDICTIONAL COST (¢/KWH)	5.3910	5.3289	6.3868	6.6631	7.4828	6.8330	6.3731	7b
9	TRUE-UP (¢/KWH)	0.2941	0.3276	0.3221	0.3247	0.2907	0.2593	0.3010	9
10	TOTAL	5.6851	5.6565	6.7089	6.9878	7.7735	7.0923	6.6741	10
11	REVENUE TAX FACTOR 0.00072	0.0041	0.0041	0.0048	0.0050	0.0056	0.0051	0.0048	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	5.6892	5.6606	6.7137	6.9928	7.7791	7.0974	6.6789	12
13	GPIF (¢/KWH)	0.0053	0.0060	0.0059	0.0059	0.0053	0.0047	0.0055	13
13a	JURISDICTIONALIZED SAVINGS-WCEC 1&2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	13a
14	RECOVERY FACTOR including GPIF	5.6945	5.6666	6.7196	6.9987	7.7844	7.1021	6.6844	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	5.695	5.667	6.720	6.999	7.784	7.102	6.684	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD NOVEMBER 2009 - DECEMBER 2009

LINE NO.		(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$683,941,154	$692,871,394	$639,279,703	$569,416,842	$417,071,062	$385,933,690	$6,214,273,493	A1
1a	NUCLEAR FUEL DISPOSAL	1,979,519	1,979,519	1,915,663	1,874,120	1,496,482	1,982,553	$21,828,572	1a
1b	COAL CAR INVESTMENT	216,695	214,833	212,970	211,108	209,245	207,383	$2,611,519	1b
1c	ADJUSTMENT FOR WEST COUNTY 1 & 2	13,737,500	13,737,500	13,737,500	13,737,500	13,737,500	13,737,500	$164,850,000	1c
1d	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	$0	1d
1e	INCREMENTAL HEDGING COSTS	53,520	74,028	53,520	53,520	53,520	53,520	$694,510	1e
2	FUEL COST OF POWER SOLD	(6,334,043)	(14,231,863)	(4,250,289)	(5,472,641)	(6,711,083)	(10,812,349)	($116,090,101)	2
2a	GAIN ON ECONOMY SALES	(634,111)	(1,653,071)	(353,664)	(478,138)	(1,204,331)	(2,886,686)	($18,447,799)	2a
3	FUEL COST OF PURCHASED POWER	31,089,900	31,131,591	29,712,418	30,849,652	30,106,446	30,141,600	$351,329,743	3
3a	QUALIFYING FACILITIES	22,820,000	23,183,000	21,679,000	19,694,000	15,956,000	20,380,000	$235,952,993	3a
4	ENERGY COST OF ECONOMY PURCHASES	9,944,038	8,946,982	17,323,797	17,029,993	7,883,060	6,490,247	$116,281,945	4
4a	FUEL COST OF SALES TO FKEC / CKW	(7,212,596)	(7,338,510)	(7,468,260)	(7,252,161)	(6,511,495)	(5,918,406)	($76,920,848)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$749,601,576	$748,915,402	$711,842,357	$639,663,794	$472,086,406	$439,309,052	$6,896,364,025	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	10,261,393	10,257,659	10,640,511	8,965,734	8,658,115	8,125,387	106,126,486	6
7	COST PER KWH SOLD (¢/KWH)	7.3051	7.3010	6.6899	7.1345	5.4525	5.4066	6.4982	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	7a
7b	JURISDICTIONAL COST (¢/KWH)	7.3092	7.3051	6.6937	7.1385	5.4556	5.4097	6.5019	7b
9	TRUE-UP (¢/KWH)	0.2409	0.2410	0.2323	0.2758	0.2852	0.3038	0.2793	9
10	TOTAL	7.5501	7.5461	6.9260	7.4143	5.7408	5.7135	6.7812	10
11	REVENUE TAX FACTOR 0.00072	0.0054	0.0054	0.0050	0.0053	0.0041	0.0041	0.0049	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	7.5555	7.5515	6.9310	7.4196	5.7449	5.7176	6.7861	12
13	GPIF (¢/KWH)	0.0044	0.0044	0.0042	0.0050	0.0052	0.0055	0.0051	13
13a	JURISDICTIONALIZED SAVINGS-WCEC 1&2	0.0000	0.0000	0.0000	0.0000	(0.3063)	(0.3263)	(0.3160)	13a
14	RECOVERY FACTOR including GPIF	7.5599	7.5559	6.9352	7.4246	5.4438	5.3968	6.4752	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	7.560	7.556	6.935	7.425	5.444	5.397	6.475	15

Generating System Comparative Data by Fuel Type

		Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09
	Fuel Cost of System Net Generation ($)						
1	Heavy Oil	$8,946,311	($384,145)	$2,248,477	$23,824,659	$69,157,869	$66,057,242
2	Light Oil	$0	$0	$0	$0	$0	$0
3	Coal	$16,270,000	$14,412,000	$13,677,000	$13,185,000	$16,146,000	$15,510,000
4	Gas	$370,181,207	$335,545,279	$411,634,930	$411,281,184	$474,271,215	$499,353,422
5	Nuclear	$11,764,000	$10,586,000	$9,136,000	$10,932,000	$9,515,000	$12,509,000
6	***Total***	$407,161,518	$360,159,134	$436,696,407	$459,222,843	$569,090,084	$593,429,664
	System Net Generation (MWH)						
7	Heavy Oil	55,727	624	16,572	148,731	428,323	386,895
8	Light Oil	0	0	0	0	0	0
9	Coal	640,236	568,237	548,383	526,709	628,073	602,628
10	Gas	4,191,087	3,931,439	4,926,310	4,930,018	5,719,802	6,050,116
11	Nuclear	2,185,554	1,974,049	1,665,445	1,931,485	1,614,028	2,046,473
12	***Total***	7,072,604	6,474,349	7,156,710	7,536,943	8,390,226	9,086,112
	Units of Fuel Burned						
13	Heavy Oil (BBLS)	87,465	1,050	25,136	222,718	642,484	611,842
14	Light Oil (BBLS)	0	0	0	0	0	0
15	Coal (TONS)	345,692	308,395	309,706	300,443	343,926	330,241
16	Gas (MCF)	31,700,100	28,728,514	36,031,376	37,366,300	43,841,164	46,121,884
17	Nuclear (MBTU)	24,370,624	22,012,168	18,477,214	21,533,546	18,079,122	22,819,234
	BTU Burned (MMBTU)						
18	Heavy Oil	559,779	6,717	160,869	1,425,393	4,111,896	3,915,792
19	Light Oil	0	0	0	0	0	0
20	Coal	6,593,673	5,860,761	5,691,844	5,527,135	6,542,032	6,280,452
21	Gas	31,700,100	28,728,514	36,031,376	37,366,300	43,841,164	46,121,884
22	Nuclear	24,370,624	22,012,168	18,477,214	21,533,546	18,079,122	22,819,234
23	***Total***	63,224,176	56,608,160	60,361,303	65,852,374	72,574,214	79,137,362

Generating System Comparative Data by Fuel Type

		Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09
	Generation Mix (%MWH)						
24	Heavy Oil	0.79%	0.01%	0.23%	1.97%	5.11%	4.26%
25	Light Oil	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	Coal	9.05%	8.78%	7.66%	6.99%	7.49%	6.63%
27	Gas	59.26%	60.72%	68.83%	65.41%	68.17%	66.59%
28	Nuclear	30.90%	30.49%	23.27%	25.63%	19.24%	22.52%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit						
30	Heavy Oil ($/BBL)	102.2845	0.0000	89.4524	106.9723	107.6414	107.9645
31	Light Oil ($/BBL)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
32	Coal ($/ton)	47.0650	46.7323	44.1612	43.8852	46.9461	46.9657
33	Gas ($/MCF)	11.6776	11.6799	11.4243	11.0067	10.8179	10.8268
34	Nuclear ($/MBTU)	0.4827	0.4809	0.4944	0.5077	0.5263	0.5482
	Fuel Cost per MMBTU ($/MMBTU)						
35	Heavy Oil	15.9819	0.0000	13.9771	16.7144	16.8190	16.8694
36	Light Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
37	Coal	2.4675	2.4591	2.4029	2.3855	2.4680	2.4696
38	Gas	11.6776	11.6799	11.4243	11.0067	10.8179	10.8268
39	Nuclear	0.4827	0.4809	0.4944	0.5077	0.5263	0.5482
	BTU burned per KWH (BTU/KWH)						
40	Heavy Oil	10,045	10,764	9,707	9,584	9,600	10,121
41	Light Oil	0	0	0	0	0	0
42	Coal	10,299	10,314	10,379	10,494	10,416	10,422
43	Gas	7,564	7,307	7,314	7,579	7,665	7,623
44	Nuclear	11,151	11,151	11,094	11,149	11,201	11,151
	Generated Fuel Cost per KWH (cents/KWH)						
45	Heavy Oil	16.0538	0.0000	13.5679	16.0186	16.1462	17.0737
46	Light Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
47	Coal	2.5413	2.5363	2.4941	2.5033	2.5707	2.5737
48	Gas	8.8326	8.5349	8.3558	8.3424	8.2917	8.2536
49	Nuclear	0.5383	0.5363	0.5486	0.5660	0.5895	0.6112
50	***Total***	5.7569	5.5629	6.1019	6.0930	6.7828	6.5312

Generating System Comparative Data by Fuel Type

		Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total
	Fuel Cost of System Net Generation ($)							
1	Heavy Oil	$112,431,885	$112,380,694	$97,801,563	$89,810,805	($167,086)	($195,424)	$581,912,849
2	Light Oil	$0	$0	$0	$0	$0	$0	$0
3	Coal	$16,433,000	$16,571,000	$16,384,000	$17,075,000	$16,663,000	$17,640,000	$189,966,000
4	Gas	$542,079,269	$550,967,700	$512,606,140	$450,309,037	$390,671,148	$354,426,114	$5,303,326,644
5	Nuclear	$12,997,000	$12,952,000	$12,488,000	$12,222,000	$9,904,000	$14,063,000	$139,068,000
6	***Total***	$683,941,154	$692,871,394	$639,279,703	$569,416,842	$417,071,062	$385,933,690	$6,214,273,493
	System Net Generation (MWH)							
7	Heavy Oil	670,993	668,957	579,398	539,965	0	0	3,496,185
8	Light Oil	0	0	0	0	0	0	0
9	Coal	630,603	634,720	602,527	635,239	616,841	633,765	7,267,961
10	Gas	6,527,986	6,631,727	6,075,149	5,324,521	4,837,253	4,235,918	63,381,326
11	Nuclear	2,131,954	2,131,954	2,063,180	2,018,438	1,611,720	2,135,221	23,509,501
12	***Total***	9,961,536	10,067,358	9,320,254	8,518,163	7,065,814	7,004,904	97,654,973
	Units of Fuel Burned							
13	Heavy Oil (BBLS)	1,034,141	1,031,165	896,527	827,415	0	0	5,379,943
14	Light Oil (BBLS)	0	0	0	0	0	0	0
15	Coal (TONS)	344,931	346,478	330,177	346,672	333,523	343,211	3,983,395
16	Gas (MCF)	49,852,992	50,451,900	46,697,668	40,015,440	33,705,344	29,393,414	473,906,096
17	Nuclear (MBTU)	23,769,566	23,769,566	23,002,796	22,483,316	17,881,176	23,800,286	261,998,614
	BTU Burned (MMBTU)							
18	Heavy Oil	6,618,504	6,599,453	5,737,771	5,295,456	0	0	34,431,630
19	Light Oil	0	0	0	0	0	0	0
20	Coal	6,565,907	6,604,420	6,279,409	6,609,287	6,355,454	6,533,350	75,443,724
21	Gas	49,852,992	50,451,900	46,697,668	40,015,440	33,705,344	29,393,414	473,906,096
22	Nuclear	23,769,566	23,769,566	23,002,796	22,483,316	17,881,176	23,800,286	261,998,614
23	***Total***	86,806,969	87,425,339	81,717,644	74,403,499	57,941,974	59,727,050	845,780,064

Generating System Comparative Data by Fuel Type

		Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total
	Generation Mix (%MWH)							
24	Heavy Oil	6.74%	6.64%	6.22%	6.34%	0.00%	0.00%	3.58%
25	Light Oil	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	Coal	6.33%	6.30%	6.46%	7.46%	8.73%	9.05%	7.44%
27	Gas	65.53%	65.87%	65.18%	62.51%	68.46%	60.47%	64.90%
28	Nuclear	21.40%	21.18%	22.14%	23.70%	22.81%	30.48%	24.07%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit							
30	Heavy Oil ($/BBL)	108.7201	108.9842	109.0894	108.5438	0.0000	0.0000	108.1634
31	Light Oil ($/BBL)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
32	Coal ($/ton)	47.6414	47.8270	49.6219	49.2540	49.9606	51.3970	47.6895
33	Gas ($/MCF)	10.8736	10.9207	10.9771	11.2534	11.5908	12.0580	11.1907
34	Nuclear ($/MBTU)	0.5468	0.5449	0.5429	0.5436	0.5539	0.5909	0.5308
	Fuel Cost per MMBTU ($/MMBTU)							
35	Heavy Oil	16.9875	17.0288	17.0452	16.9600	0.0000	0.0000	16.9005
36	Light Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
37	Coal	2.5028	2.5091	2.6092	2.5835	2.6218	2.7000	2.5180
38	Gas	10.8736	10.9207	10.9771	11.2534	11.5908	12.0580	11.1907
39	Nuclear	0.5468	0.5449	0.5429	0.5436	0.5539	0.5909	0.5308
	BTU burned per KWH (BTU/KWH)							
40	Heavy Oil	9,864	9,865	9,903	9,807	0	0	9,848
41	Light Oil	0	0	0	0	0	0	0
42	Coal	10,412	10,405	10,422	10,404	10,303	10,309	10,380
43	Gas	7,637	7,608	7,687	7,515	6,968	6,939	7,477
44	Nuclear	11,149	11,149	11,149	11,139	11,094	11,147	11,144
	Generated Fuel Cost per KWH (cents/KWH)							
45	Heavy Oil	16.7560	16.7994	16.8799	16.6327	0.0000	0.0000	16.6442
46	Light Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
47	Coal	2.6059	2.6108	2.7192	2.6880	2.7013	2.7834	2.6137
48	Gas	8.3039	8.3081	8.4378	8.4573	8.0763	8.3672	8.3673
49	Nuclear	0.6096	0.6075	0.6053	0.6055	0.6145	0.6586	0.5915
50	***Total***	6.8658	6.8824	6.8590	6.6847	5.9027	5.5095	6.3635

Company: Florida Power & Light

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Estimated For The Period of : Jan-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380	29,767	17.1	91.2	39.0	10,503	Heavy Oil	BBLS ->	46,401	6,400,056	296,989	4,747,000	15.9472
2			18,659					Gas	MCF ->	211,656	1,000,000	211,656	2,464,000	13.2053
3														
4	TURKEY POINT 2	378	14,751	12.7	92.8	41.6	10,536	Heavy Oil	BBLS ->	22,915	6,400,044	146,657	2,344,000	15.8904
5			20,968					Gas	MCF ->	229,691	1,000,000	229,691	2,700,000	12.8769
6														
7	TURKEY POINT 3	717	520,110	97.5	97.5	97.5	11,331	Nuclear	Othr ->	5,893,410	1,000,000	5,893,410	2,561,000	0.4924
8														
9	TURKEY POINT 4	717	520,110	97.5	97.5	97.5	11,331	Nuclear	Othr ->	5,893,410	1,000,000	5,893,410	3,002,000	0.5772
10														
11	TURKEY POINT 5	1,113	623,611	75.3	94.1	79.8	6,986	Gas	MCF ->	4,357,039	1,000,000	4,357,039	50,195,000	8.0491
12														
13	LAUDERDALE 4	450	120,714	36.1	94.5	70.2	8,390	Gas	MCF ->	1,012,804	1,000,000	1,012,804	11,981,000	9.9251
14														
15	LAUDERDALE 5	447	243,758	73.3	94.5	73.3	8,039	Gas	MCF ->	1,959,611	1,000,000	1,959,611	23,210,000	9.5218
16														
17	PT EVERGLADES 1	204		0.0	95.3		0							
18														
19	PT EVERGLADES 2	204		0.0	94.4		0							
20														
21	PT EVERGLADES 3	382	22,654	8.0	92.0	43.6	11,025	Gas	MCF ->	249,773	1,000,000	249,773	2,975,000	13.1324
22														
23	PT EVERGLADES 4	382	15,666	5.5	92.7	47.7	10,893	Gas	MCF ->	170,658	1,000,000	170,658	2,038,000	13.0090
24														
25	RIVIERA 3	274	8,369	8.3	91.6	49.8	10,645	Heavy Oil	BBLS ->	13,126	6,399,817	84,004	1,342,000	16.0354
26			8,561					Gas	MCF ->	96,220	1,000,000	96,220	1,135,000	13.2586
27														
28	RIVIERA 4	283	9,774	4.6	92.7	44.3	10,971	Gas	MCF ->	107,232	1,000,000	107,232	1,278,000	13.0762
29														
30	ST LUCIE 1	853	618,763	97.5	97.5	97.5	10,987	Nuclear	Othr ->	6,798,424	1,000,000	6,798,424	3,632,000	0.5870
31														

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Estimated For The Period of : Jan-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 2	726	526,572	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,785,382	1,000,000	5,785,382	2,569,000	0.4879
33													
34	CAPE CANAVERAL 1	382	42,327	14.9	94.5	39.3	10,813	Gas MCF ->	457,723	1,000,000	457,723	5,422,000	12.8097
35													
36	CAPE CANAVERAL 2	378	26,999	9.6	94.1	37.2	11,022	Gas MCF ->	297,607	1,000,000	297,607	3,530,000	13.0744
37													
38	CUTLER 5	65		0.0	99.3		0						
39													
40	CUTLER 6	138	11,127	10.8	96.6	69.5	13,885	Gas MCF ->	154,506	1,000,000	154,506	1,815,000	16.3115
41													
42	FORT MYERS 2	1,471	627,290	57.3	94.7	76.6	7,150	Gas MCF ->	4,485,239	1,000,000	4,485,239	52,399,000	8.3532
43													
44	FORT MYERS 3A_B	332	37,460	15.2	93.8	84.8	11,040	Gas MCF ->	413,584	1,000,000	413,584	4,894,000	13.0645
45													
46	SANFORD 3	141		0.0	94.7		0						
47													
48	SANFORD 4	967	358,009	49.8	94.4	83.4	7,242	Gas MCF ->	2,592,964	1,000,000	2,592,964	30,658,000	8.5635
49													
50	SANFORD 5	963	369,029	51.5	83.8	84.4	7,223	Gas MCF ->	2,665,809	1,000,000	2,665,809	31,493,000	8.5340
51													
52	PUTNAM 1	249	46,046	24.9	98.7	52.4	10,716	Gas MCF ->	493,438	1,000,000	493,438	5,817,000	12.6329
53													
54	PUTNAM 2	250	53,290	28.7	98.4	53.2	10,504	Gas MCF ->	559,805	1,000,000	559,805	6,601,000	12.3869
55													
56	MANATEE 1	806	2,571	1.0	96.6	47.5	10,878	Heavy Oil BBLS ->	4,605	6,399,566	29,470	471,000	18.3197
57			3,168					Gas MCF ->	32,965	1,000,000	32,965	395,000	12.4673
58													
59	MANATEE 2	780		0.0	95.6		0						
60													
61	MANATEE 3	1,112	671,535	81.2	94.4	82.1	6,936	Gas MCF ->	4,658,144	1,000,000	4,658,144	53,662,000	7.9910
62													

Company: Florida Power & Light

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Estimated For The Period of : Jan-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MARTIN 1	807	198	4.9	96.2	45.2	11,109	Heavy Oil BBLS ->	307	6,403,909	1,966	31,000	15.6566
64			29,324					Gas MCF ->	326,013	1,000,000	326,013	3,869,000	13.1940
65													
66	MARTIN 2	812	71.	3.3	94.9	44.3	11,087	Heavy Oil BBLS ->	111	6,432,432	714	11,000	15.4930
67			19,728					Gas MCF ->	218,800	1,000,000	218,800	2,606,000	13.2100
68													
69	MARTIN 3	448	135,583	40.7	94.2	78.4	7,668	Gas MCF ->	1,039,713	1,000,000	1,039,713	12,203,000	9.0004
70													
71	MARTIN 4	462	150,339	43.7	94.7	80.1	7,566	Gas MCF ->	1,137,501	1,000,000	1,137,501	13,371,000	8.8939
72													
73	MARTIN 8	1,112	525,475	63.5	94.1	78.1	7,177	Gas MCF ->	3,771,673	1,000,000	3,771,673	43,465,000	8.2716
74													
75	FORT MYERS 1-12	617		0.0	98.4		0						
76													
77	LAUDERDALE 1-24	684		0.0	91.7		0						
78													
79	EVERGLADES 1-12	342		0.0	88.3		0						
80													
81	ST JOHNS 1O	128	92,388	97.0	96.8	97.0	9,814	Coal TONS ->	36,183	25,060,249	906,755	2,864,000	3.1000
82													
83	ST JOHNS 2O	127	91,273	96.6	97.1	96.6	9,824	Coal TONS ->	35,782	25,059,890	896,693	2,832,000	3.1028
84													
85	SCHERER 4	628	456,575	97.8	97.1	97.8	10,491	Coal TONS ->	273,727	17,500,005	4,790,224	10,574,000	2.3159
86													
87	WCEC_01	1,335		0.0	0.0		0						
88													
89	WCEC_02	1,335		0.0	0.0		0						
90													
91	TOTAL	24,381	7,072,612				8,939				63,224,244	407,156,000	5.7568

Company: Florida Power & Light

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Estimated For The Period of : Feb-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380		0.0	19.5		0						
2													
3	TURKEY POINT 2	378	624	2.1	92.8	25.5	11,909	Heavy Oil BBLS ->	1,050	6,397,143	6,717	-384,000	-61.5385
4			4,683					Gas MCF ->	56,488	1,000,000	56,488	660,000	14.0938
5													
6	TURKEY POINT 3	717	469,777	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,323,070	1,000,000	5,323,070	2,304,000	0.4904
7													
8	TURKEY POINT 4	717	469,777	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,323,070	1,000,000	5,323,070	2,702,000	0.5752
9													
10	TURKEY POINT 5	1,113	599,657	80.2	94.1	80.2	6,970	Gas MCF ->	4,179,790	1,000,000	4,179,790	48,193,000	8.0368
11													
12	LAUDERDALE 4	450	101,612	33.6	94.5	70.1	8,297	Gas MCF ->	843,156	1,000,000	843,156	9,973,000	9.8148
13													
14	LAUDERDALE 5	447	201,164	67.0	94.5	67.0	8,171	Gas MCF ->	1,643,841	1,000,000	1,643,841	19,466,000	9.6767
15													
16	PT EVERGLADES 1	204		0.0	95.3		0						
17													
18	PT EVERGLADES 2	204		0.0	94.4		0						
19													
20	PT EVERGLADES 3	382		0.0	92.0		0						
21													
22	PT EVERGLADES 4	382		0.0	92.7		0						
23													
24	RIVIERA 3	274		0.0	88.3		0						
25													
26	RIVIERA 4	283		0.0	92.7		0						
27													
28	ST LUCIE 1	853	558,883	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,140,510	1,000,000	6,140,510	3,269,000	0.5849
29													
30	ST LUCIE 2	726	475,613	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,225,519	1,000,000	5,225,519	2,312,000	0.4861
31													

Company: Florida Power & Light

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Estimated For The Period of : Feb-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	CAPE CANAVERAL 1	382	11,047	4.3	94.5	24.5	12,006	Gas	MCF ->	132,631	1,000,000	132,631	1,552,000	14.0496
33														
34	CAPE CANAVERAL 2	378	6,318	2.5	94.1	23.5	12,184	Gas	MCF ->	76,978	1,000,000	76,978	900,000	14.2455
35														
36	CUTLER 5	65		0.0	99.3		0							
37														
38	CUTLER 6	138	3,225	3.5	96.6	37.1	15,557	Gas	MCF ->	50,182	1,000,000	50,182	588,000	18.2303
39														
40	FORT MYERS 2	1,471	700,375	70.9	90.2	73.6	7,124	Gas	MCF ->	4,989,950	1,000,000	4,989,950	58,743,000	8.3874
41														
42	FORT MYERS 3A_B	332	21,713	9.7	93.8	74.3	11,508	Gas	MCF ->	249,895	1,000,000	249,895	2,957,000	13.6184
43														
44	SANFORD 3	141		0.0	0.0		0							
45														
46	SANFORD 4	967	340,214	52.4	94.4	92.3	7,176	Gas	MCF ->	2,441,691	1,000,000	2,441,691	28,850,000	8.4800
47														
48	SANFORD 5	963	417,914	64.6	94.5	91.2	7,124	Gas	MCF ->	2,977,291	1,000,000	2,977,291	35,275,000	8.4407
49														
50	PUTNAM 1	249	27,993	16.7	98.7	41.5	11,675	Gas	MCF ->	326,827	1,000,000	326,827	3,846,000	13.7392
51														
52	PUTNAM 2	250	35,476	21.1	98.4	48.4	10,845	Gas	MCF ->	384,765	1,000,000	384,765	4,534,000	12.7803
53														
54	MANATEE 1	806		0.0	96.6		0							
55														
56	MANATEE 2	780		0.0	68.3		0							
57														
58	MANATEE 3	1,112	621,930	83.2	94.4	83.2	6,927	Gas	MCF ->	4,308,191	1,000,000	4,308,191	49,673,000	7.9869
59														
60	MARTIN 1	807		0.0	96.2		0							
61														

Company: Florida Power & Light

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Estimated For The Period of : Feb-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MARTIN 2	812		0.0	94.9		0							
63														
64	MARTIN 3	448	122,447	40.7	94.2	82.8	7,592	Gas	MCF ->	929,633	1,000,000	929,633	10,896,000	8.8985
65														
66	MARTIN 4	462	128,672	41.4	94.7	86.0	7,490	Gas	MCF ->	963,804	1,000,000	963,804	11,318,000	8.7960
67														
68	MARTIN 8	1,112	587,000	78.6	94.1	79.5	7,109	Gas	MCF ->	4,173,407	1,000,000	4,173,407	48,120,000	8.1976
69														
70	FORT MYERS 1-12	617		0.0	98.4		0							
71														
72	LAUDERDALE 1-24	684		0.0	91.7		0							
73														
74	EVERGLADES 1-12	342		0.0	88.3		0							
75														
76	ST JOHNS 10	128	77,021	89.5	93.3	92.9	9,840	Coal	TONS ->	30,243	25,060,311	757,899	2,394,000	3.1082
77														
78	ST JOHNS 20	127	79,165	92.8	97.1	92.8	9,849	Coal	TONS ->	31,113	25,060,232	779,699	2,463,000	3.1112
79														
80	SCHERER 4	628	412,051	97.7	97.1	97.7	10,491	Coal	TONS ->	247,038	17,499,996	4,323,164	9,556,000	2.3191
81														
82	WCEC_01	1,335		0.0	0.0		0							
83														
84	WCEC_02	1,335		0.0	0.0		0							
85														
86	TOTAL	24,381	6,474,350				8,743					56,608,167	360,160,000	5.5629

Company:	Florida Power & Light	Schedule E4
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Estimated For The Period of : Mar-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380		0.0	0.0		0						
2													
3	TURKEY POINT 2	378	14,363	9.7	92.8	52.2	10,293	Heavy Oil BBLS ->	21,699	6,400,065	138,875	1,941,000	13.5139
4			12,871					Gas MCF ->	141,471	1,000,000	141,471	1,640,000	12.7414
5													
6	TURKEY POINT 3	717		0.0	0.0		0						
7													
8	TURKEY POINT 4	717	520,110	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	2,981,000	0.5731
9													
10	TURKEY POINT 5	1,113	694,551	83.9	94.1	83.9	6,923	Gas MCF ->	4,808,842	1,000,000	4,808,842	54,073,000	7.7853
11													
12	LAUDERDALE 4	450	111,096	33.2	82.3	80.9	8,145	Gas MCF ->	904,967	1,000,000	904,967	10,477,000	9.4305
13													
14	LAUDERDALE 5	447	246,834	74.2	94.5	74.2	8,014	Gas MCF ->	1,978,372	1,000,000	1,978,372	22,943,000	9.2949
15													
16	PT EVERGLADES 1	204		0.0	95.3		0						
17													
18	PT EVERGLADES 2	204		0.0	94.4		0						
19													
20	PT EVERGLADES 3	382	12,146	4.3	80.1	44.8	11,033	Gas MCF ->	134,017	1,000,000	134,017	1,564,000	12.8766
21													
22	PT EVERGLADES 4	382	12,518	4.4	92.7	56.5	10,729	Gas MCF ->	134,312	1,000,000	134,312	1,571,000	12.5496
23													
24	RIVIERA 3	274	2,157	1.9	32.5	52.9	10,377	Heavy Oil BBLS ->	3,358	6,399,345	21,489	300,000	13.9082
25			1,760					Gas MCF ->	19,156	1,000,000	19,156	222,000	12.6165
26													
27	RIVIERA 4	283	7,227	3.4	92.7	50.1	10,825	Gas MCF ->	78,232	1,000,000	78,232	914,000	12.6474
28													
29	ST LUCIE 1	853	618,763	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,798,424	1,000,000	6,798,424	3,606,000	0.5828
30													

Estimated For The Period of : Mar-09

(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31 ST LUCIE 2	726	526,572	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,785,382	1,000,000	5,785,382	2,550,000	0.4843
32												
33 CAPE CANAVERAL 1	382	39,983	14.1	94.5	47.6	10,600	Gas MCF ->	423,833	1,000,000	423,833	4,943,000	12.3627
34												
35 CAPE CANAVERAL 2	378	23,371	8.3	94.1	37.5	10,961	Gas MCF ->	256,192	1,000,000	256,192	2,978,000	12.7421
36												
37 CUTLER 5	65		0.0	99.3		0						
38												
39 CUTLER 6	138	12,297	12.0	96.6	81.0	13,063	Gas MCF ->	160,646	1,000,000	160,646	1,835,000	14.9226
40												
41 FORT MYERS 2	1,471	851,237	77.8	77.4	77.8	7,072	Gas MCF ->	6,020,449	1,000,000	6,020,449	69,434,000	8.1568
42												
43 FORT MYERS 3A_B	332	48,101	19.5	93.8	89.4	10,774	Gas MCF ->	518,252	1,000,000	518,252	5,984,000	12.4405
44												
45 SANFORD 3	141		0.0	0.0		0						
46												
47 SANFORD 4	967	444,185	61.7	94.4	94.5	7,121	Gas MCF ->	3,163,302	1,000,000	3,163,302	36,513,000	8.2202
48												
49 SANFORD 5	963	579,418	80.9	94.5	88.7	7,073	Gas MCF ->	4,098,788	1,000,000	4,098,788	47,431,000	8.1860
50												
51 PUTNAM 1	249	51,973	28.1	98.7	67.8	9,785	Gas MCF ->	508,561	1,000,000	508,561	5,866,000	11.2866
52												
53 PUTNAM 2	250	23,153	12.5	41.3	69.6	9,588	Gas MCF ->	222,008	1,000,000	222,008	2,563,000	11.0700
54												
55 MANATEE 1	806		0.0	96.6		0						
56												
57 MANATEE 2	780		0.0	0.0		0						
58												
59 MANATEE 3	1,112	717,062	86.7	94.4	86.7	6,876	Gas MCF ->	4,931,109	1,000,000	4,931,109	55,448,000	7.7327
60												

Company: Florida Power & Light

Estimated For The Period of : Mar-09

	(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)
61	MARTIN 1	807	52	3.8	96.2	56.5	10,881	Heavy Oil BBLS ->	79	6,405,063	506	7,000	13.4615
62			22,756					Gas MCF ->	247,672	1,000,000	247,672	2,882,000	12.6646
63													
64	MARTIN 2	812		0.0	94.9		0						
65													
66	MARTIN 3	448	156,107	46.8	94.2	91.0	7,489	Gas MCF ->	1,169,154	1,000,000	1,169,154	13,363,000	8.5602
67													
68	MARTIN 4	462	170,811	49.7	94.7	93.1	7,399	Gas MCF ->	1,263,987	1,000,000	1,263,987	14,478,000	8.4761
69													
70	MARTIN 8	1,112	686,853	83.0	94.1	83.0	7,058	Gas MCF ->	4,848,053	1,000,000	4,848,053	54,514,000	7.9368
71													
72	FORT MYERS 1-12	617		0.0	98.4		0						
73													
74	LAUDERDALE 1-24	684		0.0	91.7		0						
75													
76	EVERGLADES 1-12	342		0.0	88.3		0						
77													
78	ST JOHNS 1O	128		0.0	0.0		0						
79													
80	ST JOHNS 2O	127	91,808	97.2	97.1	97.2	9,820	Coal TONS ->	35,978	25,060,315	901,620	3,075,000	3.3494
81													
82	SCHERER 4	628	456,575	97.8	97.1	97.8	10,491	Coal TONS ->	273,727	17,500,005	4,790,224	10,602,000	2.3221
83													
84	WCEC_01	1,335		0.0	0.0		0						
85													
86	WCEC_02	1,335		0.0	0.0		0						
87													
88	TOTAL	24,381	7,156,710				8,434				60,361,306	436,698,000	6.1019

Company: Florida Power & Light

Estimated For The Period of : Apr-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	50,904	21.7	51.7	80.5	9,636	Heavy Oil	BBLS ->	74,312	6,400,043	475,600	7,952,000	15.6216
2			8,156					Gas	MCF ->	93,510	1,000,000	93,510	1,051,000	12.8859
3														
4	TURKEY POINT 2	376	46,458	29.9	92.8	78.5	9,911	Heavy Oil	BBLS ->	68,389	6,399,991	437,689	7,318,000	15.7519
5			34,389					Gas	MCF ->	363,587	1,000,000	363,587	4,098,000	11.9165
6														
7	TURKEY POINT 3	693	421,625	84.5	84.5	97.5	11,330	Nuclear	Othr ->	4,777,394	1,000,000	4,777,394	2,637,000	0.6254
8														
9	TURKEY POINT 4	693	486,491	97.5	97.5	97.5	11,330	Nuclear	Othr ->	5,512,394	1,000,000	5,512,394	2,779,000	0.5712
10														
11	TURKEY POINT 5	1,062	652,066	85.3	94.1	85.3	6,934	Gas	MCF ->	4,521,788	1,000,000	4,521,788	48,778,000	7.4805
12														
13	LAUDERDALE 4	440	49,575	15.7	28.4	96.3	8,012	Gas	MCF ->	397,214	1,000,000	397,214	4,471,000	9.0187
14														
15	LAUDERDALE 5	437	245,194	77.9	94.5	77.9	8,078	Gas	MCF ->	1,980,700	1,000,000	1,980,700	22,240,000	9.0704
16														
17	PT EVERGLADES 1	203	2,981	2.0	95.3	91.8	11,090	Gas	MCF ->	33,069	1,000,000	33,069	372,000	12.4782
18														
19	PT EVERGLADES 2	203		0.0	94.4		0							
20														
21	PT EVERGLADES 3	380	18,292	6.7	36.8	57.3	10,694	Gas	MCF ->	195,633	1,000,000	195,633	2,196,000	12.0053
22														
23	PT EVERGLADES 4	380	53,650	19.6	92.7	72.4	10,538	Gas	MCF ->	565,383	1,000,000	565,383	6,382,000	11.8957
24														
25	RIVIERA 3	272	27,206	20.4	91.6	85.8	10,160	Heavy Oil	BBLS ->	41,019	6,400,083	262,525	4,386,000	16.1214
26			12,684					Gas	MCF ->	142,757	1,000,000	142,757	1,606,000	12.6618
27														
28	RIVIERA 4	281	27,818	13.8	92.7	68.3	10,689	Gas	MCF ->	297,350	1,000,000	297,350	3,344,000	12.0212
29														
30	ST LUCIE 1	839	588,980	97.5	97.5	97.5	10,987	Nuclear	Othr ->	6,471,126	1,000,000	6,471,126	3,421,000	0.5808
31														

Company: Florida Power & Light

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Estimated For The Period of : Apr-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 2	714	434,390	84.5	84.5	97.5	10,986	Nuclear Othr ->	4,772,632	1,000,000	4,772,632	2,096,000	0.4825
33													
34	CAPE CANAVERAL 1	380	101,730	37.2	94.5	80.9	10,104	Gas MCF ->	1,027,952	1,000,000	1,027,952	11,632,000	11.4342
35													
36	CAPE CANAVERAL 2	376	55,044	20.3	94.1	67.2	10,418	Gas MCF ->	573,470	1,000,000	573,470	6,479,000	11.7705
37													
38	CUTLER 5	64	1,017	2.2	9.9	99.3	14,757	Gas MCF ->	15,008	1,000,000	15,008	166,000	16.3273
39													
40	CUTLER 6	137	27,389	27.8	96.6	94.7	12,832	Gas MCF ->	351,470	1,000,000	351,470	3,864,000	14.1081
41													
42	FORT MYERS 2	1,389	766,190	76.6	94.7	84.7	7,108	Gas MCF ->	5,446,812	1,000,000	5,446,812	60,522,000	7.8991
43													
44	FORT MYERS 3A_B	304	89,041	40.7	93.8	94.5	10,834	Gas MCF ->	964,685	1,000,000	964,685	10,782,000	12.1090
45													
46	SANFORD 3	139		0.0	88.1		0						
47													
48	SANFORD 4	909	498,882	76.2	94.4	87.4	7,143	Gas MCF ->	3,563,560	1,000,000	3,563,560	39,676,000	7.9530
49													
50	SANFORD 5	905	492,846	75.6	94.5	77.6	7,253	Gas MCF ->	3,574,714	1,000,000	3,574,714	39,362,000	7.9867
51													
52	PUTNAM 1	239	79,606	46.3	98.7	93.6	9,046	Gas MCF ->	720,179	1,000,000	720,179	8,082,000	10.1525
53													
54	PUTNAM 2	240		0.0	0.0		0						
55													
56	MANATEE 1	798	10,371	3.0	96.6	67.7	10,785	Heavy Oil BBLS ->	18,164	6,400,132	116,252	1,942,000	18.7253
57			6,914					Gas MCF ->	70,176	1,000,000	70,176	791,000	11.4401
58													
59	MANATEE 2	772		0.0	0.0		0						
60													
61	MANATEE 3	1,061	649,006	85.0	94.4	85.0	6,936	Gas MCF ->	4,501,740	1,000,000	4,501,740	48,562,000	7.4825
62													

Company: Florida Power & Light

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Estimated For The Period of : Apr-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MARTIN 1	796	9,805	11.8	96.2	77.5	10,785	Heavy Oil	BBLS ->	14,806	6,400,176	94,761	1,583,000	16.1448
64			58,032					Gas	MCF ->	636,901	1,000,000	636,901	7,118,000	12.2656
65														
66	MARTIN 2	799	3,986	5.5	94.9	76.1	10,856	Heavy Oil	BBLS ->	6,026	6,399,934	38,566	644,000	16.1565
67			27,643					Gas	MCF ->	304,800	1,000,000	304,800	3,401,000	12.3034
68														
69	MARTIN 3	417	149,114	49.7	94.2	86.8	7,565	Gas	MCF ->	1,128,049	1,000,000	1,128,049	12,398,000	8.3144
70														
71	MARTIN 4	431	189,222	61.0	94.7	95.4	7,411	Gas	MCF ->	1,402,400	1,000,000	1,402,400	15,431,000	8.1550
72														
73	MARTIN 8	1,049	633,539	83.9	94.1	83.9	7,092	Gas	MCF ->	4,493,398	1,000,000	4,493,398	48,472,000	7.6510
74														
75	FORT MYERS 1-12	588		0.0	98.4		0							
76														
77	LAUDERDALE 1-24	678		0.0	91.7		0							
78														
79	EVERGLADES 1-12	339		0.0	88.3		0							
80														
81	ST JOHNS 10	125	8,211	9.1	9.7	91.2	9,953	Coal	TONS ->	3,261	25,061,944	81,727	267,000	3.2517
82														
83	ST JOHNS 20	124	81,443	91.2	97.1	91.2	9,960	Coal	TONS ->	32,372	25,060,175	811,248	2,648,000	3.2514
84														
85	SCHERER 4	624	437,055	97.3	97.1	97.3	10,603	Coal	TONS ->	264,809	17,500,009	4,634,160	10,270,000	2.3498
86														
87	WCEC_01	1,219		0.0	0.0		0							
88														
89	WCEC_02	1,219		0.0	0.0		0							
90														
91	TOTAL	23,472	7,536,944				8,737					65,852,377	459,219,000	6.0929

Company: Florida Power & Light

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Estimated For The Period of : May-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	123,300	46.9	91.2	93.5	9,534	Heavy Oil BBLS ->	179,030	6,400,000	1,145,792	19,279,000	15.6358
2			8,538					Gas MCF ->	111,212	1,000,000	111,212	1,233,000	14.4408
3													
4	TURKEY POINT 2	376	66,659	39.1	92.8	88.2	9,805	Heavy Oil BBLS ->	97,567	6,399,982	624,427	10,507,000	15.7623
5			42,823					Gas MCF ->	449,107	1,000,000	449,107	5,020,000	11.7226
6													
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,132,000	0.6230
8													
9	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	2,861,000	0.5691
10													
11	TURKEY POINT 5	1,062	658,434	83.3	91.1	83.3	6,961	Gas MCF ->	4,583,921	1,000,000	4,583,921	48,419,000	7.3537
12													
13	LAUDERDALE 4	440	231,956	70.9	94.5	82.9	8,104	Gas MCF ->	1,879,786	1,000,000	1,879,786	20,702,000	8.9250
14													
15	LAUDERDALE 5	437	243,664	74.9	94.5	82.5	8,024	Gas MCF ->	1,955,295	1,000,000	1,955,295	21,552,000	8.8450
16													
17	PT EVERGLADES 1	203		0.0	95.3		0						
18													
19	PT EVERGLADES 2	203		0.0	94.4		0						
20													
21	PT EVERGLADES 3	380	46,954	29.3	92.0	83.5	10,152	Heavy Oil BBLS ->	70,567	6,399,960	451,626	7,592,000	16.1690
22			35,847					Gas MCF ->	389,028	1,000,000	389,028	4,320,000	12.0514
23													
24	PT EVERGLADES 4	380	41,286	25.5	92.7	79.5	10,213	Heavy Oil BBLS ->	62,379	6,399,990	399,225	6,712,000	16.2573
25			30,873					Gas MCF ->	337,755	1,000,000	337,755	3,752,000	12.1532
26													
27	RIVIERA 3	272	45,467	29.5	91.6	91.9	10,037	Heavy Oil BBLS ->	68,264	6,399,977	436,888	7,345,000	16.1546
28			14,250					Gas MCF ->	162,528	1,000,000	162,528	1,805,000	12.6664
29													
30	RIVIERA 4	281	52,656	25.2	92.7	78.7	10,540	Gas MCF ->	555,012	1,000,000	555,012	6,162,000	11.7023
31													

Company: Florida Power & Light

Estimated For The Period of : May-09

Line	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 1	839	608,613	97.5	97.5	97.5	10,986	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	3,522,000	0.5787
33													
34	ST LUCIE 2	714		0.0	0.0		0						
35													
36	CAPE CANAVERAL 1	380	27,385	47.7	94.5	91.5	9,923	Heavy Oil BBLS ->	39,986	6,399,940	255,908	4,304,000	15.7166
37			107,500					Gas MCF ->	1,082,685	1,000,000	1,082,685	12,137,000	11.2902
38													
39	CAPE CANAVERAL 2	376	15,052	27.2	94.1	71.2	10,284	Heavy Oil BBLS ->	22,424	6,400,018	143,514	2,413,000	16.0311
40			60,937					Gas MCF ->	637,959	1,000,000	637,959	7,113,000	11.6728
41													
42	CUTLER 5	64	6,102	12.8	64.0	99.3	14,855	Gas MCF ->	90,644	1,000,000	90,644	984,000	16.1267
43													
44	CUTLER 6	137	25,459	25.0	96.6	94.3	12,910	Gas MCF ->	328,671	1,000,000	328,671	3,533,000	13.8774
45													
46	FORT MYERS 2	1,389	863,591	83.6	94.7	83.6	7,101	Gas MCF ->	6,132,811	1,000,000	6,132,811	66,846,000	7.7405
47													
48	FORT MYERS 3A_B	304	84,650	37.4	93.8	95.4	10,809	Gas MCF ->	915,042	1,000,000	915,042	9,994,000	11.8062
49													
50	SANFORD 3	139		0.0	97.9		0						
51													
52	SANFORD 4	909	445,191	65.8	94.4	95.8	7,125	Gas MCF ->	3,172,130	1,000,000	3,172,130	34,736,000	7.8025
53													
54	SANFORD 5	905	599,108	89.0	94.5	89.0	7,073	Gas MCF ->	4,237,977	1,000,000	4,237,977	45,879,000	7.6579
55													
56	PUTNAM 1	239	94,867	53.4	98.7	96.3	8,967	Gas MCF ->	850,718	1,000,000	850,718	9,320,000	9.8243
57													
58	PUTNAM 2	240	53,181	29.8	73.0	69.0	9,630	Gas MCF ->	512,165	1,000,000	512,165	5,644,000	10.6127
59													
60	MANATEE 1	798	10,388	2.9	96.6	67.8	10,783	Heavy Oil BBLS ->	18,189	6,399,912	116,408	1,957,000	18.8390
61			6,925					Gas MCF ->	70,286	1,000,000	70,286	789,000	11.3932
62													

Company: Florida Power & Light

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Estimated For The Period of : May-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 2	772	30,353	8.8	83.3	91.0	10,616	Heavy Oil BBLS ->	51,679	6,400,027	330,747	5,561,000	18.3211
64			20,235					Gas MCF ->	206,323	1,000,000	206,323	2,313,000	11.4305
65													
66	MANATEE 3	1,061	671,870	85.1	94.4	85.1	6,932	Gas MCF ->	4,658,036	1,000,000	4,658,036	49,202,000	7.3231
67													
68	MARTIN 1	796	17,136	21.0	96.2	76.4	10,778	Heavy Oil BBLS ->	25,846	6,400,101	165,417	2,781,000	16.2290
69			106,939					Gas MCF ->	1,171,889	1,000,000	1,171,889	12,889,000	12.0526
70													
71	MARTIN 2	799	4,343	12.4	94.9	70.8	10,928	Heavy Oil BBLS ->	6,554	6,399,603	41,943	705,000	16.2330
72			69,220					Gas MCF ->	762,000	1,000,000	762,000	8,398,000	12.1323
73													
74	MARTIN 3	417	252,012	81.2	94.2	87.5	7,488	Gas MCF ->	1,887,257	1,000,000	1,887,257	20,323,000	8.0643
75													
76	MARTIN 4	431	273,879	85.4	94.7	87.3	7,418	Gas MCF ->	2,031,795	1,000,000	2,031,795	21,886,000	7.9911
77													
78	MARTIN 8	1,049	659,095	84.5	81.9	84.4	7,084	Gas MCF ->	4,669,135	1,000,000	4,669,135	49,319,000	7.4828
79													
80	FORT MYERS 1-12	588		0.0	87.8		0						
81													
82	LAUDERDALE 1-24	678		0.0	91.7		0						
83													
84	EVERGLADES 1-12	339		0.0	88.3		0						
85													
86	ST JOHNS 10	125	87,884	94.5	96.8	94.5	9,928	Coal TONS ->	34,817	25,060,172	872,520	2,756,000	3.1360
87													
88	ST JOHNS 20	124	86,751	94.0	97.1	94.0	9,939	Coal TONS ->	34,407	25,059,988	862,239	2,723,000	3.1389
89													
90	SCHERER 4	624	453,438	97.7	97.1	97.7	10,601	Coal TONS ->	274,701	17,500,024	4,807,274	10,667,000	2.3525
91													
92	WCEC_01	1,219		0.0	0.0		0						
93													

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : May-09

	(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)
94	WCEC_02	1,219		0.0	0.0		0						
95													
96	TOTAL	23,472	8,390,226				8,650				72,574,213	569,087,000	6.7827

Company: Florida Power & Light

Schedule E4
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Estimated For The Period of : Jun-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	33,321	15.0	91.2	96.6	9,675	Heavy Oil	BBLS ->	48,323	6,400,017	309,268	5,221,000	15.6688
2			7,572					Gas	MCF ->	86,395	1,000,000	86,395	982,000	12.9687
3														
4	TURKEY POINT 2	376	17,672	10.3	92.8	92.6	9,862	Heavy Oil	BBLS ->	25,868	6,399,876	165,552	2,795,000	15.8160
5			10,194					Gas	MCF ->	109,276	1,000,000	109,276	1,234,000	12.1048
6														
7	TURKEY POINT 3	693	486,491	97.5	97.5	97.5	11,330	Nuclear	Othr ->	5,512,394	1,000,000	5,512,394	3,021,000	0.6210
8														
9	TURKEY POINT 4	693	486,491	97.5	97.5	97.5	11,330	Nuclear	Othr ->	5,512,394	1,000,000	5,512,394	2,759,000	0.5671
10														
11	TURKEY POINT 5	1,062	647,450	84.7	40.8	84.7	6,939	Gas	MCF ->	4,492,794	1,000,000	4,492,794	47,570,000	7.3473
12														
13	LAUDERDALE 4	440	200,534	63.3	94.5	80.1	8,193	Gas	MCF ->	1,643,134	1,000,000	1,643,134	18,139,000	9.0454
14														
15	LAUDERDALE 5	437	208,655	66.3	94.5	82.0	8,081	Gas	MCF ->	1,686,292	1,000,000	1,686,292	18,625,000	8.9262
16														
17	PT EVERGLADES 1	203		0.0	95.3		0							
18														
19	PT EVERGLADES 2	203		0.0	94.4		0							
20														
21	PT EVERGLADES 3	380		0.0	92.0		0							
22														
23	PT EVERGLADES 4	380		0.0	92.7		0							
24														
25	RIVIERA 3	272		0.0	91.6		0							
26														
27	RIVIERA 4	281		0.0	92.7		0							
28														
29	ST LUCIE 1	839	588,980	97.5	97.5	97.5	10,987	Nuclear	Othr ->	6,471,126	1,000,000	6,471,126	3,397,000	0.5768
30														

33

Company: Florida Power & Light

Estimated For The Period of : Jun-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUCIE 2	714	484,511	94.3	94.3	97.5	10,986	Nuclear Othr ->	5,323,320	1,000,000	5,323,320	3,333,000	0.6879
32													
33	CAPE CANAVERAL 1	380	723	13.7	94.5	94.7	10,111	Heavy Oil BBLS ->	1,055	6,401,896	6,754	114,000	15.7676
34			36,704					Gas MCF ->	371,694	1,000,000	371,694	4,236,000	11.5409
35													
36	CAPE CANAVERAL 2	376		0.0	94.1		0						
37													
38	CUTLER 5	64	254	0.6	99.3	99.3	15,052	Gas MCF ->	3,827	1,000,000	3,827	43,000	16.9425
39													
40	CUTLER 6	137	8,503	8.6	96.6	98.5	13,138	Gas MCF ->	111,713	1,000,000	111,713	1,208,000	14.2073
41													
42	FORT MYERS 2	1,389	831,954	83.2	94.7	83.2	7,106	Gas MCF ->	5,912,201	1,000,000	5,912,201	64,197,000	7.7164
43													
44	FORT MYERS 3A_B	304	23,460	10.7	93.8	96.5	10,844	Gas MCF ->	254,418	1,000,000	254,418	2,816,000	12.0036
45													
46	SANFORD 3	139		0.0	97.9		0						
47													
48	SANFORD 4	909	220,659	33.7	94.4	97.9	7,263	Gas MCF ->	1,602,768	1,000,000	1,602,768	17,514,000	7.9371
49													
50	SANFORD 5	905	576,918	88.5	83.5	88.5	7,079	Gas MCF ->	4,084,208	1,000,000	4,084,208	44,615,000	7.7333
51													
52	PUTNAM 1	239	47,085	27.4	98.7	97.5	9,051	Gas MCF ->	426,207	1,000,000	426,207	4,716,000	10.0159
53													
54	PUTNAM 2	240	39,320	22.8	98.4	74.1	9,591	Gas MCF ->	377,150	1,000,000	377,150	4,173,000	10.6131
55													
56	MANATEE 1	798	102,472	37.6	96.6	48.0	10,482	Heavy Oil BBLS ->	167,911	6,400,010	1,074,632	18,127,000	17.6897
57			113,645					Gas MCF ->	1,190,841	1,000,000	1,190,841	13,055,000	11.4876
58													
59	MANATEE 2	772	143,659	51.1	95.6	63.7	10,360	Heavy Oil BBLS ->	231,064	6,399,997	1,478,809	24,945,000	17.3640
60			140,466					Gas MCF ->	1,464,853	1,000,000	1,464,853	16,090,000	11.4547
61													

Company: Florida Power & Light

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Estimated For The Period of : Jun-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 3	1,061	651,712	85.3	94.4	85.3	6,927	Gas MCF ->	4,515,042	1,000,000	4,515,042	47,805,000	7.3353
63													
64	MARTIN 1	796	56,858	53.1	96.2	62.3	10,439	Heavy Oil BBLS ->	87,778	6,399,975	561,777	9,475,000	16.6643
65			247,432					Gas MCF ->	2,614,949	1,000,000	2,614,949	28,674,000	11.5886
66													
67	MARTIN 2	799	32,190	46.5	94.9	56.8	10,540	Heavy Oil BBLS ->	49,844	6,399,948	318,999	5,380,000	16.7133
68			235,529					Gas MCF ->	2,502,793	1,000,000	2,502,793	27,386,000	11.6274
69													
70	MARTIN 3	417	218,798	72.9	94.2	87.6	7,515	Gas MCF ->	1,644,362	1,000,000	1,644,362	17,767,000	8.1203
71													
72	MARTIN 4	431	244,914	78.9	94.7	87.4	7,437	Gas MCF ->	1,821,442	1,000,000	1,821,442	19,690,000	8.0396
73													
74	MARTIN 8	1,049	635,963	84.2	84.7	84.2	7,085	Gas MCF ->	4,506,097	1,000,000	4,506,097	49,065,000	7.7151
75													
76	FORT MYERS 1-12	588		0.0	98.4		0						
77													
78	LAUDERDALE 1-24	678		0.0	91.7		0						
79													
80	EVERGLADES 1-12	339		0.0	88.3		0						
81													
82	ST JOHNS 1O	125	84,155	93.5	96.8	93.5	9,938	Coal TONS ->	33,374	25,059,837	836,347	2,641,000	3.1383
83													
84	ST JOHNS 2O	124	82,921	92.9	97.1	92.9	9,950	Coal TONS ->	32,927	25,059,647	825,139	2,606,000	3.1428
85													
86	SCHERER 4	624	435,552	97.0	97.1	97.0	10,604	Coal TONS ->	263,941	17,499,998	4,618,967	10,263,000	2.3563
87													
88	WCEC_01	1,219	702,394	80.0	96.1	80.0	6,690	Gas MCF ->	4,699,433	1,000,000	4,699,433	49,757,000	7.0839
89													
90	WCEC_02	1,219		0.0	0.0		0						
91													

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jun-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
92	TOTAL	23,472	9,086,109				8,710				79,137,365	593,434,000	6.5312

Company: Florida Power & Light

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Estimated For The Period of : Jul-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	61,275	23.8	91.2	97.3	9,615	Heavy Oil	BBLS ->	88,854	6,399,959	568,662	9,666,000	15.7748
2			5,660					Gas	MCF ->	74,952	1,000,000	74,952	841,000	14.8592
3														
4	TURKEY POINT 2	376	44,121	16.9	92.8	96.5	9,695	Heavy Oil	BBLS ->	64,528	6,399,950	412,976	7,020,000	15.9108
5			3,061					Gas	MCF ->	44,483	1,000,000	44,483	505,000	16.4984
6														
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,330	Nuclear	Othr ->	5,696,144	1,000,000	5,696,144	3,110,000	0.6187
8														
9	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,330	Nuclear	Othr ->	5,696,144	1,000,000	5,696,144	2,840,000	0.5649
10														
11	TURKEY POINT 5	1,062	688,224	87.1	94.1	87.1	6,907	Gas	MCF ->	4,753,630	1,000,000	4,753,630	50,446,000	7.3299
12														
13	LAUDERDALE 4	440	226,979	69.3	94.5	83.6	8,113	Gas	MCF ->	1,841,527	1,000,000	1,841,527	20,393,000	8.9845
14														
15	LAUDERDALE 5	437	239,189	73.6	94.5	85.5	7,993	Gas	MCF ->	1,911,878	1,000,000	1,911,878	21,182,000	8.8558
16														
17	PT EVERGLADES 1	203		0.0	95.3		0							
18														
19	PT EVERGLADES 2	203		0.0	94.4		0							
20														
21	PT EVERGLADES 3	380	18,818	8.2	92.0	94.9	9,979	Heavy Oil	BBLS ->	28,164	6,400,121	180,253	3,061,000	16.2663
22			4,268					Gas	MCF ->	50,126	1,000,000	50,126	577,000	13.5195
23														
24	PT EVERGLADES 4	380		0.0	92.7		0							
25														
26	RIVIERA 3	272		0.0	91.6		0							
27														
28	RIVIERA 4	281		0.0	92.7		0							
29														
30	ST LUCIE 1	839	608,613	97.5	97.5	97.5	10,986	Nuclear	Othr ->	6,686,833	1,000,000	6,686,833	3,497,000	0.5746
31														

Company: Florida Power & Light

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Estimated For The Period of : Jul-09

(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
ST LUCIE 2	714	517,926	97.5	97.5	97.5	10,986	Nuclear	Othr ->	5,690,445	1,000,000	5,690,445	3,550,000	0.6854
CAPE CANAVERAL 1	380	46,115	20.6	94.5	96.9	9,727	Heavy Oil	BBLS ->	67,277	6,400,003	430,573	7,315,000	15.8625
		12,039					Gas	MCF ->	135,122	1,000,000	135,122	1,536,000	12.7591
CAPE CANAVERAL 2	376	29,343	14.2	94.1	94.6	9,930	Heavy Oil	BBLS ->	43,509	6,399,963	278,456	4,731,000	16.1231
		10,476					Gas	MCF ->	116,979	1,000,000	116,979	1,353,000	12.9159
CUTLER 5	64	2,224	4.7	99.3	99.3	14,951	Gas	MCF ->	33,260	1,000,000	33,260	362,000	16.2748
CUTLER 6	137	13,632	13.4	96.6	98.5	13,162	Gas	MCF ->	179,427	1,000,000	179,427	1,942,000	14.2460
FORT MYERS 2	1,389	873,809	84.6	94.7	84.6	7,090	Gas	MCF ->	6,195,645	1,000,000	6,195,645	67,459,000	7.7201
FORT MYERS 3A_B	304	41,348	18.3	93.8	96.5	10,825	Gas	MCF ->	447,619	1,000,000	447,619	4,966,000	12.0103
SANFORD 3	139		0.0	97.9		0							
SANFORD 4	909	246,239	36.4	94.4	82.3	7,447	Gas	MCF ->	1,833,950	1,000,000	1,833,950	20,068,000	8.1498
SANFORD 5	905	603,719	89.7	94.5	89.7	7,063	Gas	MCF ->	4,264,609	1,000,000	4,264,609	46,786,000	7.7496
PUTNAM 1	239	54,215	30.5	98.7	97.8	9,040	Gas	MCF ->	490,116	1,000,000	490,116	5,436,000	10.0267
PUTNAM 2	240	44,279	24.8	98.4	76.2	9,513	Gas	MCF ->	421,257	1,000,000	421,257	4,672,000	10.5513
MANATEE 1	798	133,996	44.5	96.6	53.5	10,309	Heavy Oil	BBLS ->	214,441	6,399,989	1,372,420	23,311,000	17.3968
		130,061					Gas	MCF ->	1,349,797	1,000,000	1,349,797	14,867,000	11.4308
MANATEE 2	772	184,886	60.5	95.6	72.2	10,243	Heavy Oil	BBLS ->	292,752	6,399,994	1,873,611	31,825,000	17.2133
		162,751					Gas	MCF ->	1,687,391	1,000,000	1,687,391	18,668,000	11.4703

Company: Florida Power & Light

Estimated For The Period of : Jul-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
64	MANATEE 3	1,061	684,712	86.7	94.4	86.7	6,909	Gas MCF ->	4,731,073	1,000,000	4,731,073	50,206,000	7.3324
65													
66	MARTIN 1	796	98,074	60.9	96.2	69.5	10,324	Heavy Oil BBLS ->	150,855	6,399,980	965,469	16,398,000	16.7200
67			262,756					Gas MCF ->	2,759,965	1,000,000	2,759,965	30,589,000	11.6416
68													
69	MARTIN 2	799	54,364	54.4	94.9	63.4	10,419	Heavy Oil BBLS ->	83,763	6,399,998	536,083	9,105,000	16.7482
70			268,778					Gas MCF ->	2,830,925	1,000,000	2,830,925	31,292,000	11.6423
71													
72	MARTIN 3	417	262,661	84.7	94.2	86.9	7,485	Gas MCF ->	1,966,132	1,000,000	1,966,132	21,290,000	8.1055
73													
74	MARTIN 4	431	276,334	86.2	94.7	87.2	7,416	Gas MCF ->	2,049,489	1,000,000	2,049,489	22,209,000	8.0370
75													
76	MARTIN 8	1,049	667,819	85.6	94.1	85.6	7,065	Gas MCF ->	4,718,639	1,000,000	4,718,639	51,745,000	7.7484
77													
78	FORT MYERS 1-12	588		0.0	98.4		0						
79													
80	LAUDERDALE 1-24	678		0.0	91.7		0						
81													
82	EVERGLADES 1-12	339		0.0	88.3		0						
83													
84	ST JOHNS 10	125	88,979	95.7	96.8	95.7	9,920	Coal TONS ->	35,225	25,060,014	882,739	2,882,000	3.2390
85													
86	ST JOHNS 20	124	87,890	95.3	97.1	95.3	9,930	Coal TONS ->	34,830	25,059,661	872,828	2,849,000	3.2416
87													
88	SCHERER 4	624	453,734	97.8	97.1	97.8	10,601	Coal TONS ->	274,877	17,499,976	4,810,341	10,702,000	2.3587
89													
90	WCEC_01	1,219	742,755	81.9	96.2	81.9	6,684	Gas MCF ->	4,965,002	1,000,000	4,965,002	52,689,000	7.0937
91													
92	WCEC_02	1,219		0.0	0.0		0						
93													

Company: Florida Power & Light

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Estimated For The Period of : Jul-09

	(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)
94	TOTAL	23,472	9,961,534				8,714				88,806,967	683,941,000	6.8658

Company: Florida Power & Light

Estimated For The Period of : Aug-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	78,997	30.2	91.2	97.0	9,589	Heavy Oil BBLS ->	114,562	6,399,993	733,196	12,493,000	15.8145
2			6,048					Gas MCF ->	82,338	1,000,000	82,338	934,000	15.4436
3													
4	TURKEY POINT 2	376	53,849	22.2	92.8	96.5	9,726	Heavy Oil BBLS ->	78,756	6,400,008	504,039	8,588,000	15.9483
5			8,226					Gas MCF ->	99,746	1,000,000	99,746	1,147,000	13.9438
6													
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,100,000	0.6167
8													
9	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	2,830,000	0.5630
10													
11	TURKEY POINT 5	1,062	713,922	90.4	94.1	90.4	6,861	Gas MCF ->	4,898,795	1,000,000	4,898,795	52,184,000	7.3095
12													
13	LAUDERDALE 4	440	223,115	68.2	94.5	86.8	8,047	Gas MCF ->	1,795,589	1,000,000	1,795,589	19,972,000	8.9514
14													
15	LAUDERDALE 5	437	252,045	77.5	94.5	88.2	7,913	Gas MCF ->	1,994,440	1,000,000	1,994,440	22,200,000	8.8080
16													
17	PT EVERGLADES 1	203		0.0	95.3		0						
18													
19	PT EVERGLADES 2	203		0.0	94.4		0						
20													
21	PT EVERGLADES 3	380	35,309	15.2	92.0	94.1	9,980	Heavy Oil BBLS ->	52,861	6,399,936	338,307	5,759,000	16.3103
22			7,602					Gas MCF ->	89,980	1,000,000	89,980	1,039,000	13.6673
23													
24	PT EVERGLADES 4	380	22,899	9.1	92.7	93.6	9,981	Heavy Oil BBLS ->	34,399	6,399,953	220,152	3,748,000	16.3675
25			2,714					Gas MCF ->	35,496	1,000,000	35,496	409,000	15.0711
26													
27	RIVIERA 3	272		0.0	91.6		0						
28													
29	RIVIERA 4	281		0.0	92.7		0						
30													

Company: Florida Power & Light

Estimated For The Period of : Aug-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUCIE 1	839	608,613	97.5	97.5	97.5	10,986	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	3,485,000	0.5726
32													
33	ST LUCIE 2	714	517,926	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	3,538,000	0.6831
34													
35	CAPE CANAVERAL 1	380	47,143	25.7	94.5	97.1	9,797	Heavy Oil BBLS ->	68,773	6,399,997	440,147	7,495,000	15.8984
36			25,554					Gas MCF ->	272,109	1,000,000	272,109	3,136,000	12.2723
37													
38	CAPE CANAVERAL 2	376	31,255	19.9	94.1	92.6	10,022	Heavy Oil BBLS ->	46,350	6,400,043	296,642	5,052,000	16.1638
39			24,479					Gas MCF ->	261,948	1,000,000	261,948	3,028,000	12.3698
40													
41	CUTLER 5	64	4,004	8.4	99.3	99.3	14,996	Gas MCF ->	60,047	1,000,000	60,047	656,000	16.3820
42													
43	CUTLER 6	137	15,926	15.6	96.6	98.5	13,129	Gas MCF ->	209,105	1,000,000	209,105	2,268,000	14.2406
44													
45	FORT MYERS 2	1,389	890,419	86.2	94.7	86.2	7,068	Gas MCF ->	6,293,668	1,000,000	6,293,668	68,739,000	7.7199
46													
47	FORT MYERS 3A_B	304	39,588	17.5	93.8	96.5	10,841	Gas MCF ->	429,193	1,000,000	429,193	4,780,000	12.0743
48													
49	SANFORD 3	139		0.0	97.9		0						
50													
51	SANFORD 4	909	260,698	38.6	94.4	97.9	7,236	Gas MCF ->	1,886,417	1,000,000	1,886,417	20,753,000	7.9605
52													
53	SANFORD 5	905	618,933	91.9	94.5	91.9	7,032	Gas MCF ->	4,352,726	1,000,000	4,352,726	47,872,000	7.7346
54													
55	PUTNAM 1	239	56,552	31.8	98.7	97.8	9,038	Gas MCF ->	511,138	1,000,000	511,138	5,690,000	10.0615
56													
57	PUTNAM 2	240	46,994	26.3	98.4	77.1	9,481	Gas MCF ->	445,564	1,000,000	445,564	4,960,000	10.5544
58													
59	MANATEE 1	798	112,367	37.9	96.6	51.3	10,421	Heavy Oil BBLS ->	183,319	6,399,997	1,173,241	19,977,000	17.7784
60			112,404					Gas MCF ->	1,169,289	1,000,000	1,169,289	12,918,000	11.4925
61													

Company: Florida Power & Light

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Estimated For The Period of : Aug-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 2	772	174,414	56.9	95.6	71.0	10,283	Heavy Oil	BBLS ->	278,346	6,399,991	1,781,412	30,332,000	17.3908
63			152,214					Gas	MCF ->	1,577,425	1,000,000	1,577,425	17,511,000	11.5042
64														
65	MANATEE 3	1,061	716,421	90.8	94.4	90.8	6,854	Gas	MCF ->	4,910,964	1,000,000	4,910,964	52,314,000	7.3021
66														
67	MARTIN 1	796	82,739	60.7	96.2	63.5	10,297	Heavy Oil	BBLS ->	127,639	6,399,995	816,889	13,908,000	16.8095
68			276,900					Gas	MCF ->	2,886,550	1,000,000	2,886,550	32,114,000	11.5977
69														
70	MARTIN 2	799	29,985	49.5	94.9	58.9	10,485	Heavy Oil	BBLS ->	46,161	6,399,948	295,428	5,030,000	16.7751
71			264,377					Gas	MCF ->	2,790,980	1,000,000	2,790,980	30,962,000	11.7113
72														
73	MARTIN 3	417	251,437	81.0	94.2	88.5	7,474	Gas	MCF ->	1,879,388	1,000,000	1,879,388	20,425,000	8.1233
74														
75	MARTIN 4	431	219,714	68.5	94.7	73.5	7,530	Gas	MCF ->	1,654,514	1,000,000	1,654,514	17,994,000	8.1897
76														
77	MARTIN 8	1,049	691,089	88.6	94.1	88.5	7,019	Gas	MCF ->	4,851,175	1,000,000	4,851,175	53,555,000	7.7494
78														
79	FORT MYERS 1-12	588		0.0	98.4		0							
80														
81	LAUDERDALE 1-24	678		0.0	91.7		0							
82														
83	EVERGLADES 1-12	339		0.0	88.3		0							
84														
85	ST JOHNS 10	125	91,136	98.0	96.8	98.0	9,907	Coal	TONS ->	36,029	25,060,118	902,891	2,947,000	3.2336
86														
87	ST JOHNS 20	124	89,794	97.3	97.1	97.3	9,918	Coal	TONS ->	35,539	25,059,737	890,598	2,907,000	3.2374
88														
89	SCHERER 4	624	453,790	97.8	97.1	97.8	10,601	Coal	TONS ->	274,910	17,500,025	4,810,932	10,717,000	2.3617
90														
91	WCEC_01	1,219	750,353	82.7	96.2	82.7	6,681	Gas	MCF ->	5,013,311	1,000,000	5,013,311	53,404,000	7.1172
92														

Company: Florida Power & Light

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Estimated For The Period of : Aug-09

	(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)
93	WCEC_02	1,219		0.0	0.0		0						
94													
95	TOTAL	23,472	10,067,359				8,684				87,425,330	692,870,000	6.8823

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Sep-09

Line	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	71,206	29.9	91.2	97.1	9,626	Heavy Oil BBLS ->	103,258	6,400,008	660,852	11,272,000	15.8301
2			10,290					Gas MCF ->	123,676	1,000,000	123,676	1,387,000	13.4788
3													
4	TURKEY POINT 2	376	40,111	20.7	92.8	96.3	9,782	Heavy Oil BBLS ->	58,665	6,400,051	375,459	6,404,000	15.9657
5			16,014					Gas MCF ->	173,597	1,000,000	173,597	1,978,000	12.3515
6													
7	TURKEY POINT 3	693	486,491	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	2,989,000	0.6144
8													
9	TURKEY POINT 4	693	486,491	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	2,728,000	0.5608
10													
11	TURKEY POINT 5	1,062	661,089	86.5	94.1	86.5	6,918	Gas MCF ->	4,573,758	1,000,000	4,573,758	49,079,000	7.4240
12													
13	LAUDERDALE 4	440	216,693	68.4	94.5	82.9	8,137	Gas MCF ->	1,763,300	1,000,000	1,763,300	19,730,000	9.1050
14													
15	LAUDERDALE 5	437	232,625	73.9	94.5	84.2	8,023	Gas MCF ->	1,866,538	1,000,000	1,866,538	20,898,000	8.9836
16													
17	PT EVERGLADES 1	203	4,701	3.2	95.3	96.5	10,530	Heavy Oil BBLS ->	7,735	6,400,517	49,508	833,000	17.7196
18													
19	PT EVERGLADES 2	203		0.0	34.6		0						
20													
21	PT EVERGLADES 3	380	14,659	10.6	92.0	94.9	10,126	Heavy Oil BBLS ->	21,941	6,399,845	140,419	2,393,000	16.3244
22			14,198					Gas MCF ->	151,798	1,000,000	151,798	1,731,000	12.1921
23													
24	PT EVERGLADES 4	380	7,149	5.2	92.7	94.1	10,167	Heavy Oil BBLS ->	10,737	6,399,925	68,716	1,171,000	16.3799
25			7,149					Gas MCF ->	76,652	1,000,000	76,652	875,000	12.2402
26													
27	RIVIERA 3	272	7,371	5.4	91.6	96.8	10,092	Heavy Oil BBLS ->	11,047	6,399,837	70,699	1,205,000	16.3478
28			3,159					Gas MCF ->	35,565	1,000,000	35,565	406,000	12.8526
29													
30	RIVIERA 4	281	10,226	5.1	92.7	91.0	10,517	Gas MCF ->	107,557	1,000,000	107,557	1,206,000	11.7934
31													

Company: Florida Power & Light

Estimated For The Period of : Sep-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 1	839	588,980	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,471,126	1,000,000	6,471,126	3,360,000	0.5705
34	ST LUCIE 2	714	501,219	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,506,882	1,000,000	5,506,882	3,411,000	0.6805
36	CAPE CANAVERAL 1	380	15,918	25.7	94.5	96.7	9,992	Heavy Oil BBLS ->	23,222	6,400,009	148,621	2,534,000	15.9191
37			54,255					Gas MCF ->	552,579	1,000,000	552,579	6,268,000	11.5528
39	CAPE CANAVERAL 2	376	3,817	17.1	94.1	93.8	10,237	Heavy Oil BBLS ->	5,660	6,400,177	36,225	618,000	16.1907
40			42,401					Gas MCF ->	436,934	1,000,000	436,934	5,004,000	11.8017
42	CUTLER 5	64	2,542	5.5	99.3	99.3	15,052	Gas MCF ->	38,268	1,000,000	38,268	421,000	16.5618
44	CUTLER 6	137	12,687	12.9	80.5	98.5	13,143	Gas MCF ->	166,748	1,000,000	166,748	1,823,000	14.3687
46	FORT MYERS 2	1,389	844,127	84.4	94.7	84.4	7,094	Gas MCF ->	5,988,315	1,000,000	5,988,315	65,800,000	7.7950
48	FORT MYERS 3A_B	304	41,934	19.2	93.8	96.5	10,828	Gas MCF ->	454,095	1,000,000	454,095	5,084,000	12.1238
50	SANFORD 3	139	1,731	1.7	97.9	77.8	11,264	Gas MCF ->	19,500	1,000,000	19,500	218,000	12.5924
52	SANFORD 4	909	292,729	44.7	86.5	97.9	7,199	Gas MCF ->	2,107,616	1,000,000	2,107,616	23,275,000	7.9510
54	SANFORD 5	905	581,577	89.3	83.5	89.3	7,070	Gas MCF ->	4,112,025	1,000,000	4,112,025	45,531,000	7.8289
56	PUTNAM 1	239	42,297	24.6	79.0	77.3	9,571	Gas MCF ->	404,833	1,000,000	404,833	4,536,000	10.7241
58	PUTNAM 2	240	43,334	25.1	98.4	76.5	9,513	Gas MCF ->	412,243	1,000,000	412,243	4,618,000	10.6568
60	MANATEE 1	798	129,033	44.2	96.6	53.9	10,315	Heavy Oil BBLS ->	206,757	6,399,986	1,323,242	22,555,000	17.4800
61			124,656					Gas MCF ->	1,293,585	1,000,000	1,293,585	14,402,000	11.5534

Company: Florida Power & Light

Estimated For The Period of : Sep-09

Line	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 2	772	179,041	60.6	95.6	71.4	10,244	Heavy Oil BBLS ->	283,644	6,400,001	1,815,322	30,943,000	17.2826
64			157,606					Gas MCF ->	1,633,521	1,000,000	1,633,521	18,216,000	11.5579
66	MANATEE 3	1,061	538,631	70.5	79.4	70.5	7,138	Gas MCF ->	3,844,922	1,000,000	3,844,922	41,258,000	7.6598
68	MARTIN 1	796	73,513	60.5	96.2	66.8	10,331	Heavy Oil BBLS ->	113,149	6,399,995	724,153	12,342,000	16.7889
69			273,008					Gas MCF ->	2,855,770	1,000,000	2,855,770	31,725,000	11.6206
71	MARTIN 2	799	32,879	33.3	56.9	63.1	10,405	Heavy Oil BBLS ->	50,712	6,399,965	324,555	5,532,000	16.8253
72			158,588					Gas MCF ->	1,667,755	1,000,000	1,667,755	18,529,000	11.6837
74	MARTIN 3	417	100,962	33.6	50.3	74.3	7,607	Gas MCF ->	768,075	1,000,000	768,075	8,407,000	8.3269
76	MARTIN 4	431	230,752	74.4	94.7	80.4	7,477	Gas MCF ->	1,725,440	1,000,000	1,725,440	18,892,000	8.1872
78	MARTIN 8	1,049	640,158	84.8	94.1	84.8	7,079	Gas MCF ->	4,532,189	1,000,000	4,532,189	49,683,000	7.7611
80	FORT MYERS 1-12	588		0.0	98.4		0						
82	LAUDERDALE 1-24	678		0.0	91.7		0						
84	EVERGLADES 1-12	339		0.0	88.3		0						
86	ST JOHNS 1O	125	84,026	93.4	96.8	93.4	9,937	Coal TONS ->	33,322	25,060,140	835,054	3,058,000	3.6393
88	ST JOHNS 2O	124	83,097	93.1	97.1	93.1	9,948	Coal TONS ->	32,988	25,060,052	826,681	3,027,000	3.6427
90	SCHERER 4	624	435,404	96.9	97.1	96.9	10,605	Coal TONS ->	263,867	17,500,006	4,617,674	10,300,000	2.3656
92	WCEC_01	1,219	719,733	82.0	96.1	82.0	6,684	Gas MCF ->	4,810,809	1,000,000	4,810,809	51,622,000	7.1724

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Estimated For The Period of : Sep-09

	(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)
94	WCEC_02	1,219		0.0	0.0		0						
95													
96	TOTAL	23,472	9,320,256				8,768				81,717,637	639,277,000	6.8590

Company: Florida Power & Light

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Estimated For The Period of : Oct-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	43,242	19.2	91.2	96.4	9,673	Heavy Oil BBLS ->	62,706	6,400,010	401,319	6,811,000	15.7509
2			10,676					Gas MCF ->	120,237	1,000,000	120,237	1,383,000	12.9540
3													
4	TURKEY POINT 2	376	16,754	9.3	92.8	95.8	9,838	Heavy Oil BBLS ->	24,505	6,399,918	156,830	2,662,000	15.8887
5			9,182					Gas MCF ->	98,349	1,000,000	98,349	1,133,000	12.3394
6													
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,077,000	0.6121
8													
9	TURKEY POINT 4	693	389,192	75.5	75.5	97.5	11,330	Nuclear Othr ->	4,409,894	1,000,000	4,409,894	2,174,000	0.5586
10													
11	TURKEY POINT 5	1,062	761,748	96.4	94.1	96.4	6,801	Gas MCF ->	5,181,355	1,000,000	5,181,355	57,282,000	7.5198
12													
13	LAUDERDALE 4	440	103,428	31.6	94.5	98.4	8,098	Gas MCF ->	837,638	1,000,000	837,638	9,586,000	9.2683
14													
15	LAUDERDALE 5	437	74,406	22.9	67.1	98.4	8,036	Gas MCF ->	597,930	1,000,000	597,930	6,850,000	9.2063
16													
17	PT EVERGLADES 1	203		0.0	95.3		0						
18													
19	PT EVERGLADES 2	203		0.0	0.0		0						
20													
21	PT EVERGLADES 3	380	14,428	5.1	92.0	94.9	10,369	Gas MCF ->	149,619	1,000,000	149,619	1,726,000	11.9625
22													
23	PT EVERGLADES 4	380	11,478	4.1	92.7	94.4	10,406	Gas MCF ->	119,441	1,000,000	119,441	1,378,000	12.0061
24													
25	RIVIERA 3	272	4,422	3.1	91.6	96.8	10,092	Heavy Oil BBLS ->	6,628	6,399,970	42,419	719,000	16.2596
26			1,895					Gas MCF ->	21,339	1,000,000	21,339	245,000	12.9267
27													
28	RIVIERA 4	281		0.0	92.7		0						
29													
30	ST LUCIE 1	839	608,613	97.5	97.5	97.5	10,986	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	3,459,000	0.5683
31													

Company: Florida Power & Light

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Estimated For The Period of : Oct-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 2	714	517,926	97.5	97.5	97.5	10,986	Nuclear	Othr ->	5,690,445	1,000,000	5,690,445	3,512,000	0.6781
33														
34	CAPE CANAVERAL 1	380	37,652	13.3	94.5	95.3	10,116	Gas	MCF ->	380,909	1,000,000	380,909	4,394,000	11.6700
35														
36	CAPE CANAVERAL 2	376	17,110	6.1	94.1	94.8	10,279	Gas	MCF ->	175,881	1,000,000	175,881	2,029,000	11.8588
37														
38	CUTLER 5	64		0.0	99.3		0							
39														
40	CUTLER 6	137		0.0	0.0		0							
41														
42	FORT MYERS 2	1,389	680,567	65.9	94.7	92.4	7,069	Gas	MCF ->	4,811,457	1,000,000	4,811,457	54,469,000	8.0035
43														
44	FORT MYERS 3A_B	304	30,791	13.6	93.8	96.5	10,855	Gas	MCF ->	334,261	1,000,000	334,261	3,814,000	12.3868
45														
46	SANFORD 3	139		0.0	97.9		0							
47														
48	SANFORD 4	909	389,711	57.6	47.2	97.9	7,126	Gas	MCF ->	2,777,414	1,000,000	2,777,414	31,438,000	8.0670
49														
50	SANFORD 5	905	382,324	56.8	94.5	83.7	7,280	Gas	MCF ->	2,783,519	1,000,000	2,783,519	31,571,000	8.2576
51														
52	PUTNAM 1	239	46,737	26.3	98.7	97.8	9,049	Gas	MCF ->	422,944	1,000,000	422,944	4,826,000	10.3258
53														
54	PUTNAM 2	240	27,394	15.3	52.4	52.8	10,650	Gas	MCF ->	291,750	1,000,000	291,750	3,335,000	12.1743
55														
56	MANATEE 1	798	174,130	53.3	96.6	56.9	10,098	Heavy Oil	BBLS ->	270,166	6,399,991	1,729,060	29,323,000	16.8397
57			142,303					Gas	MCF ->	1,466,522	1,000,000	1,466,522	16,799,000	11.8051
58														
59	MANATEE 2	772	236,872	73.2	95.6	75.9	10,051	Heavy Oil	BBLS ->	364,904	6,400,009	2,335,389	39,605,000	16.7200
60			183,716					Gas	MCF ->	1,892,096	1,000,000	1,892,096	21,728,000	11.8270
61														

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Estimated For The Period of : Oct-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 3	1,061	761,624	96.5	87.5	96.5	6,796	Gas	MCF ->	5,176,368	1,000,000	5,176,368	57,373,000	7.5330
63														
64	MARTIN 1	796	64,545	68.2	96.2	68.2	10,177	Heavy Oil	BBLS ->	98,506	6,399,996	630,438	10,691,000	16.5636
65			339,112					Gas	MCF ->	3,477,870	1,000,000	3,477,870	39,711,000	11.7103
66														
67	MARTIN 2	799		0.0	0.0		0							
68														
69	MARTIN 3	417	114,891	37.0	94.2	95.7	7,551	Gas	MCF ->	867,553	1,000,000	867,553	9,772,000	8.5054
70														
71	MARTIN 4	431	120,824	37.7	62.6	89.6	7,519	Gas	MCF ->	908,588	1,000,000	908,588	10,242,000	8.4768
72														
73	MARTIN 8	1,049	222,789	28.6	30.3	96.1	6,946	Gas	MCF ->	1,547,541	1,000,000	1,547,541	17,592,000	7.8963
74														
75	FORT MYERS 1-12	588		0.0	98.4		0							
76														
77	LAUDERDALE 1-24	678		0.0	91.7		0							
78														
79	EVERGLADES 1-12	339		0.0	88.3		0							
80														
81	ST JOHNS 1O	125	91,407	98.3	96.8	98.3	9,905	Coal	TONS ->	36,130	25,060,089	905,421	3,187,000	3.4866
82														
83	ST JOHNS 2O	124	90,043	97.6	97.1	97.6	9,916	Coal	TONS ->	35,632	25,059,918	892,935	3,143,000	3.4906
84														
85	SCHERER 4	624	453,790	97.8	97.1	97.8	10,601	Coal	TONS ->	274,910	17,500,025	4,810,932	10,744,000	2.3676
86														
87	WCEC_01	1,219	839,738	92.6	96.2	92.6	6,638	Gas	MCF ->	5,574,858	1,000,000	5,574,858	61,632,000	7.3394
88														
89	WCEC_02	1,219		0.0	0.0		0							
90														
91	TOTAL	23,472	8,518,166				8,735					74,403,496	569,415,000	6.6847

Company: Florida Power & Light

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Estimated For The Period of : Nov-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380		0.0	91.2		0						
2													
3	TURKEY POINT 2	378		0.0	92.8		0						
4													
5	TURKEY POINT 3	717	503,332	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,703,297	1,000,000	5,703,297	3,070,000	0.6099
6													
7	TURKEY POINT 4	717		0.0	0.0		0						
8													
9	TURKEY POINT 5	1,113	659,910	82.4	94.1	83.3	6,925	Gas MCF ->	4,570,002	1,000,000	4,570,002	54,037,000	8.1885
10													
11	LAUDERDALE 4	450	22,041	6.8	94.5	75.4	8,252	Gas MCF ->	181,894	1,000,000	181,894	2,144,000	9.7274
12													
13	LAUDERDALE 5	447	46,955	14.6	94.5	74.5	8,170	Gas MCF ->	383,661	1,000,000	383,661	4,515,000	9.6156
14													
15	PT EVERGLADES 1	204		0.0	95.3		0						
16													
17	PT EVERGLADES 2	204		0.0	0.0		0						
18													
19	PT EVERGLADES 3	382		0.0	92.0		0						
20													
21	PT EVERGLADES 4	382		0.0	92.7		0						
22													
23	RIVIERA 3	274		0.0	91.6		0						
24													
25	RIVIERA 4	283		0.0	92.7		0						
26													
27	ST LUCIE 1	853	598,803	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,579,119	1,000,000	6,579,119	3,391,000	0.5663
28													
29	ST LUCIE 2	726	509,586	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,598,761	1,000,000	5,598,761	3,443,000	0.6756
30													

Company: Florida Power & Light

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Estimated For The Period of : Nov-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	CAPE CANAVERAL 1	382		0.0	94.5		0							
32														
33	CAPE CANAVERAL 2	378		0.0	94.1		0							
34														
35	CUTLER 5	65		0.0	99.3		0							
36														
37	CUTLER 6	138		0.0	0.0		0							
38														
39	FORT MYERS 2	1,471	553,771	52.3	94.7	80.4	7,121	Gas	MCF ->	3,943,608	1,000,000	3,943,608	45,942,000	8.2962
40														
41	FORT MYERS 3A_B	332	849	0.4	93.8	63.9	12,212	Gas	MCF ->	10,367	1,000,000	10,367	122,000	14.3715
42														
43	SANFORD 3	141		0.0	97.9		0							
44														
45	SANFORD 4	967	300,623	43.2	84.9	95.4	7,160	Gas	MCF ->	2,152,628	1,000,000	2,152,628	24,997,000	8.3151
46														
47	SANFORD 5	963	291,753	42.1	83.5	82.8	7,325	Gas	MCF ->	2,137,329	1,000,000	2,137,329	24,807,000	8.5028
48														
49	PUTNAM 1	249	4,319	2.4	98.7	72.3	9,645	Gas	MCF ->	41,656	1,000,000	41,656	491,000	11.3692
50														
51	PUTNAM 2	250	8,266	4.6	72.2	82.7	9,241	Gas	MCF ->	76,394	1,000,000	76,394	903,000	10.9237
52														
53	MANATEE 1	806		0.0	96.6		0							
54														
55	MANATEE 2	780		0.0	95.6		0							
56														
57	MANATEE 3	1,112	699,205	87.3	94.4	87.3	6,875	Gas	MCF ->	4,807,304	1,000,000	4,807,304	55,091,000	7.8791
58														
59	MARTIN 1	807	4,862	0.8	96.2	31.7	10,899	Gas	MCF ->	52,988	1,000,000	52,988	619,000	12.7324
60														

Company: Florida Power & Light

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Estimated For The Period of : Nov-09

	(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)
61	MARTIN 2	812		0.0	25.3		0							
62														
63	MARTIN 3	448	98,547	30.6	94.2	84.9	7,563	Gas	MCF ->	745,354	1,000,000	745,354	8,626,000	8.7532
64														
65	MARTIN 4	462	109,142	32.8	94.7	80.1	7,561	Gas	MCF ->	825,255	1,000,000	825,255	9,551,000	8.7510
66														
67	MARTIN 8	1,112	565,970	70.7	94.1	86.7	7,046	Gas	MCF ->	3,988,252	1,000,000	3,988,252	46,811,000	8.2709
68														
69	FORT MYERS 1-12	617		0.0	98.4		0							
70														
71	LAUDERDALE 1-24	684		0.0	91.7		0							
72														
73	EVERGLADES 1-12	342		0.0	88.3		0							
74														
75	ST JOHNS 1O	128	87,916	95.4	96.8	95.4	9,823	Coal	TONS ->	34,463	25,059,803	863,636	3,162,000	3.5966
76														
77	ST JOHNS 2O	127	87,078	95.2	97.1	95.2	9,831	Coal	TONS ->	34,163	25,059,802	856,118	3,135,000	3.6002
78														
79	SCHERER 4	628	441,847	97.8	97.1	97.8	10,491	Coal	TONS ->	264,897	17,500,013	4,635,701	10,366,000	2.3461
80														
81	WCEC_01	1,335	767,275	79.8	96.1	79.8	6,632	Gas	MCF ->	5,088,861	1,000,000	5,088,861	58,235,000	7.5898
82														
83	WCEC_02	1,335	703,766	73.2	97.0	74.0	6,678	Gas	MCF ->	4,699,792	1,000,000	4,699,792	53,783,000	7.6422
84														
85	TOTAL	24,381	7,065,814				8,200					57,941,975	417,241,000	5.9051

Company: Florida Power & Light

Estimated For The Period of : Dec-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380		0.0	91.2		0						
2													
3	TURKEY POINT 2	378		0.0	92.8		0						
4													
5	TURKEY POINT 3	717	520,110	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	3,161,000	0.6078
6													
7	TURKEY POINT 4	717	469,777	88.1	88.1	97.5	11,331	Nuclear Othr ->	5,323,070	1,000,000	5,323,070	3,866,000	0.8229
8													
9	TURKEY POINT 5	1,113	611,157	73.8	94.1	81.3	6,960	Gas MCF ->	4,253,735	1,000,000	4,253,735	52,082,000	8.5219
10													
11	LAUDERDALE 4	450		0.0	94.5		0						
12													
13	LAUDERDALE 5	447	4,350	1.3	94.5	74.9	8,077	Gas MCF ->	35,137	1,000,000	35,137	433,000	9.9538
14													
15	PT EVERGLADES 1	204		0.0	95.3		0						
16													
17	PT EVERGLADES 2	204		0.0	54.8		0						
18													
19	PT EVERGLADES 3	382		0.0	92.0		0						
20													
21	PT EVERGLADES 4	382		0.0	92.7		0						
22													
23	RIVIERA 3	274		0.0	91.6		0						
24													
25	RIVIERA 4	283		0.0	92.7		0						
26													
27	ST LUCIE 1	853	618,763	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,798,424	1,000,000	6,798,424	3,491,000	0.5642
28													
29	ST LUCIE 2	726	526,572	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,785,382	1,000,000	5,785,382	3,545,000	0.6732
30													

Estimated For The Period of : Dec-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	CAPE CANAVERAL 1	382		0.0	94.5		0						
32													
33	CAPE CANAVERAL 2	378		0.0	94.1		0						
34													
35	CUTLER 5	65		0.0	99.3		0						
36													
37	CUTLER 6	138		0.0	74.8		0						
38													
39	FORT MYERS 2	1,471	551,436	50.4	94.7	76.0	7,149	Gas MCF ->	3,942,467	1,000,000	3,942,467	47,786,000	8.6657
40													
41	FORT MYERS 3A_B	332		0.0	93.8		0						
42													
43	SANFORD 3	141		0.0	97.9		0						
44													
45	SANFORD 4	967	228,651	31.8	94.4	90.9	7,172	Gas MCF ->	1,639,976	1,000,000	1,639,976	19,826,000	8.6708
46													
47	SANFORD 5	963	197,467	27.6	94.5	81.4	7,327	Gas MCF ->	1,446,900	1,000,000	1,446,900	17,488,000	8.8562
48													
49	PUTNAM 1	249		0.0	98.7		0						
50													
51	PUTNAM 2	250		0.0	98.4		0						
52													
53	MANATEE 1	806		0.0	96.6		0						
54													
55	MANATEE 2	780		0.0	95.6		0						
56													
57	MANATEE 3	1,112	697,796	84.3	94.4	86.6	6,891	Gas MCF ->	4,808,849	1,000,000	4,808,849	57,447,000	8.2326
58													
59	MARTIN 1	807		0.0	96.2		0						
60													

Company: Florida Power & Light

Estimated For The Period of : Dec-09

	(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)
61	MARTIN 2	812		0.0	94.9		0							
63	MARTIN 3	448	4,762	1.4	94.2	75.9	7,746	Gas	MCF ->	36,889	1,000,000	36,889	446,000	9.3652
65	MARTIN 4	462	27,263	7.9	94.7	78.7	7,603	Gas	MCF ->	207,288	1,000,000	207,288	2,503,000	9.1809
67	MARTIN 8	1,112	502,306	60.7	94.1	83.7	7,098	Gas	MCF ->	3,565,402	1,000,000	3,565,402	43,446,000	8.6493
69	FORT MYERS 1-12	617		0.0	98.4		0							
71	LAUDERDALE 1-24	684		0.0	91.7		0							
73	EVERGLADES 1-12	342		0.0	88.3		0							
75	ST JOHNS 1O	128	89,157	93.6	96.8	93.6	9,834	Coal	TONS ->	34,990	25,059,789	876,842	3,474,000	3.8965
77	ST JOHNS 2O	127	88,448	93.6	97.1	93.6	9,842	Coal	TONS ->	34,740	25,060,046	870,586	3,450,000	3.9006
79	SCHERER 4	628	456,160	97.7	97.1	97.7	10,491	Coal	TONS ->	273,481	17,500,016	4,785,922	10,716,000	2.3492
81	WCEC_01	1,335	757,521	76.3	96.2	76.3	6,658	Gas	MCF ->	5,044,268	1,000,000	5,044,268	60,257,000	7.9545
83	WCEC_02	1,335	653,207	65.8	97.0	65.8	6,755	Gas	MCF ->	4,412,505	1,000,000	4,412,505	52,710,000	8.0694
85	TOTAL	24,381	7,004,904	0.0			8,526					59,727,051	386,127,000	5.5122

Company: Florida Power & Light

Estimated For The Period of : Jan-09 Thru Dec-09

Line	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	379	492,012	15.8	74.7	77.2	9,682	Heavy Oil BBLS ->	717,446	6,400,005	4,591,658	77,441,000	15.7397
2			75,600					Gas MCF ->	903,975	1,000,000	903,975	10,275,000	13.5913
3			0						0		0	0	0.0000
4													
5	TURKEY POINT 2	377	315,362	14.5	92.8	77.7	9,911	Heavy Oil BBLS ->	463,942	6,399,983	2,969,221	49,195,000	15.5995
6			162,412					Gas MCF ->	1,765,794	1,000,000	1,765,794	20,115,000	12.3852
7			0						0		0	0	0.0000
8													
9	TURKEY POINT 3	703	5,418,764	88.0	88.1	97.3	11,331	Nuclear Othr ->	61,399,945	1,000,000	61,399,945	32,162,000	0.5935
10													
11													
12	TURKEY POINT 4	703	5,336,560	86.7	86.8	97.3	11,331	Nuclear Othr ->	60,468,468	1,000,000	60,468,468	31,522,000	0.5907
13													
14													
15	TURKEY POINT 5	1,083	7,971,818	84.0	89.5	85.2	6,921	Gas MCF ->	55,175,447	1,000,000	55,175,447	612,338,000	7.6813
16													
17	LAUDERDALE 4	444	1,607,744	41.3	88.0	81.7	8,149	Gas MCF ->	13,101,006	1,000,000	13,101,006	147,568,000	9.1786
18													
19													
20	LAUDERDALE 5	441	2,238,838	57.9	92.2	79.4	8,037	Gas MCF ->	17,993,696	1,000,000	17,993,696	204,114,000	9.1170
21													
22	PT EVERGLADES 1	203	2,981	0.4	95.3	94.4	10,749	Gas MCF ->	33,069	1,000,000	33,069	372,000	12.4782
23			4,701					Heavy Oil BBLS ->	7,735	6,400,517	49,508	833,000	17.7196
24			0						0		0	0	0.0000
25													
26	PT EVERGLADES 2	203	0	0.0	70.3	0.0	0		0		0	0	0.0000
27													
28	PT EVERGLADES 3	381	129,435	7.3	86.5	75.2	10,281	Gas MCF ->	1,409,974	1,000,000	1,409,974	16,128,000	12.4604
29			115,740					Heavy Oil BBLS ->	173,533	6,399,964	1,110,605	18,805,000	16.2476
30			0						0		0	0	0.0000
31													

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Estimated For The Period of : Jan-09 Thru Dec-09

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	PT EVERGLADES 4	381	134,047	6.2	92.7	74.7	10,360	Gas MCF ->	1,439,696	1,000,000	1,439,696	16,405,000	12.2383
33			71,334					Heavy Oil BBLS ->	107,515	6,399,972	688,093	11,631,000	16.3050
34			0						0		0	0	0.0000
35													
36	RIVIERA 3	273	94,992	5.7	86.3	80.5	10,164	Heavy Oil BBLS ->	143,442	6,399,967	918,024	15,297,000	16.1035
37			42,308					Gas MCF ->	477,564	1,000,000	477,564	5,419,000	12.8083
38			0						0		0	0	0.0000
39													
40	RIVIERA 4	282	107,700	4.4	92.7	69.2	10,635	Gas MCF ->	1,145,382	1,000,000	1,145,382	12,904,000	11.9814
41			0						0		0	0	0.0000
42													
43	ST LUCIE 1	845	7,215,367	97.5	97.5	97.5	10,987	Nuclear Othr ->	79,275,611	1,000,000	79,275,611	41,530,000	0.5756
44													
45	ST LUCIE 2	719	5,538,813	87.9	87.9	97.6	10,987	Nuclear Othr ->	60,854,595	1,000,000	60,854,595	33,859,000	0.6113
46													
47													
48	CAPE CANAVERAL 1	381	468,791	18.2	94.5	76.0	10,097	Gas MCF ->	4,837,236	1,000,000	4,837,236	55,256,000	11.7869
49			137,284					Heavy Oil BBLS ->	200,313	6,399,999	1,282,003	21,762,000	15.8518
50			0						0		0	0	0.0000
51													
52	CAPE CANAVERAL 2	377	267,134	10.5	94.1	66.6	10,354	Gas MCF ->	2,833,947	1,000,000	2,833,947	32,414,000	12.1340
53			79,467					Heavy Oil BBLS ->	117,943	6,400,015	754,837	12,814,000	16.1249
54			0						0		0	0	0.0000
55													
56	CUTLER 5	64	16,143	2.9	88.9	98.7	14,932	Gas MCF ->	241,052	1,000,000	241,052	2,632,000	16.3044
57			0						0		0	0	0.0000
58													
59	CUTLER 6	137	130,245	10.8	77.3	88.3	13,148	Gas MCF ->	1,712,467	1,000,000	1,712,467	18,876,000	14.4927
60			0						0		0	0	0.0000
61													

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Estimated For The Period of : Jan-09 Thru Dec-09

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)		(I)	(J)	(K)	(L)	(M)
	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)
62	FORT MYERS 2	1,423	9,034,764	72.5	92.9	81.8	7,102	Gas	MCF ->	64,162,622	1,000,000	64,162,622	722,336,000	7.9951
63														
64	FORT MYERS 3A_B	316	458,936	16.6	93.8	91.3	10,876	Gas	MCF ->	4,991,411	1,000,000	4,991,411	56,193,000	12.2442
65														
66														
67	SANFORD 3	140	1,731	0.1	81.0	77.4	11,264	Gas	MCF ->	19,500	1,000,000	19,500	218,000	12.5924
68			0							0		0	0	0.0000
69														
70	SANFORD 4	933	4,025,790	49.2	89.0	92.3	7,187	Gas	MCF ->	28,934,417	1,000,000	28,934,417	328,304,000	8.1550
71														
72	SANFORD 5	929	5,711,006	70.2	90.9	86.5	7,133	Gas	MCF ->	40,735,894	1,000,000	40,735,894	458,110,000	8.0215
73														
74	PUTNAM 1	243	551,691	25.9	97.1	80.2	9,419	Gas	MCF ->	5,196,617	1,000,000	5,196,617	58,626,000	10.6266
75														
76														
77	PUTNAM 2	244	374,687	17.5	77.2	65.1	9,883	Gas	MCF ->	3,703,101	1,000,000	3,703,101	42,003,000	11.2102
78			0							0		0	0	0.0000
79														
80	MANATEE 1	801	675,328	18.7	96.6	53.0	10,322	Heavy Oil	BBLS ->	1,083,552	6,399,993	6,934,725	117,663,000	17.4231
81			640,076					Gas	MCF ->	6,643,461	1,000,000	6,643,461	74,016,000	11.5636
82			0							0		0	0	0.0000
83														
84	MANATEE 2	775	949,225	26.0	76.5	71.2	10,235	Heavy Oil	BBLS ->	1,502,389	6,400,000	9,615,290	163,211,000	17.1941
85			816,988					Gas	MCF ->	8,461,608	1,000,000	8,461,608	94,526,000	11.5701
86			0							0		0	0	0.0000
87														
88	MANATEE 3	1,082	8,081,501	85.2	92.5	85.5	6,911	Gas	MCF ->	55,851,740	1,000,000	55,851,740	618,041,000	7.6476
89														
90	MARTIN 1	801	402,920	28.9	98.2	65.9	10,371	Heavy Oil	BBLS ->	618,965	6,400,000	3,961,376	67,216,000	16.6822
91			1,621,122					Gas	MCF ->	17,030,567	1,000,000	17,030,567	190,190,000	11.7320
92			0							0		0	0	0.0000
93														

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Estimated For The Period of : Jan-09 Thru Dec-09

	(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)
94	MARTIN 2	804	157,818	17.1	78.0	60.5	10,514	Heavy Oil BBLS ->	243,171	6,399,974	1,556,288	26,407,000	16.7326
95			1,043,863					Gas MCF ->	11,078,052	1,000,000	11,078,052	122,574,000	11.7423
96			0						0		0	0	0.0000
97													
98	MARTIN 3	430	1,867,322	49.6	90.6	85.3	7,530	Gas MCF ->	14,061,558	1,000,000	14,061,558	155,916,000	8.3497
99													
100	MARTIN 4	444	2,141,865	55.1	92.0	84.0	7,466	Gas MCF ->	15,991,502	1,000,000	15,991,502	177,565,000	8.2902
101													
102	MARTIN 8	1,075	7,018,056	74.5	86.8	84.2	7,077	Gas MCF ->	49,664,960	1,000,000	49,664,960	555,787,000	7.9194
103													
104	FORT MYERS 1-12	600	0	0.0	97.5	0.0	0		0		0	0	0.0000
105													
106	LAUDERDALE 1-24	681	0	0.0	91.7	0.0	0		0		0	0	0.0000
107													
108	EVERGLADES 1-12	340	0	0.0	88.3	0.0	0		0		0	0	0.0000
109													
110	ST JOHNS 1O	126	882,280	79.8	81.1	95.2	9,886	Coal TONS ->	348,037	25,060,068	8,721,831	29,632,000	3.3586
111													
112													
113	ST JOHNS 2O	125	1,039,711	94.8	97.1	94.8	9,894	Coal TONS ->	410,471	25,059,953	10,286,384	34,858,000	3.3527
114													
115	SCHERER 4	625	5,345,971	97.6	97.1	97.6	10,557	Coal TONS ->	3,224,885	17,500,009	56,435,515	125,477,000	2.3471
116													
117	WCEC_01	1,267	5,279,769	82.2	96.1	81.1	6,666	Gas MCF ->	35,196,541	1,000,000	35,196,541	387,596,000	7.3412
118													
119	WCEC_02	1,267	1,356,974	69.5	97.0	73.5	6,715	Gas MCF ->	9,112,297	1,000,000	9,112,297	106,493,000	7.8478
120													
121	TOTAL	23,851	97,654,984				8,661				845,780,127	6,214,625,000	6.3639

Company: Florida Power & Light

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System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2009 thru June 2009

			January 2009	February 2009	March 2009	April 2009	May 2009	June 2009
	Heavy Oil							
1	Purchases:							
2	Units	(BBLS)	97,466	41,049	295,136	467,717	1,069,484	1,011,841
3	Unit Cost	($/BBLS)	108.1813	109.3327	107.4318	107.1994	107.7286	108.0328
4	Amount	($)	10,544,000	4,488,000	31,707,000	50,139,000	115,214,000	109,312,000
5								
6	Burned:							
7	Units	(BBLS)	87,466	1,050	25,136	222,716	642,484	611,841
8	Unit Cost	($/BBLS)	102.2719	-365.8528	89.4127	106.9733	107.6398	107.9647
9	Amount	($)	8,945,311	-384,145	2,247,477	23,824,659	69,156,869	66,057,242
10								
11	Ending Inventory:							
12	Units	(BBLS)	3,120,000	3,160,000	3,430,000	3,675,000	4,102,000	4,501,997
13	Unit Cost	($/BBLS)	104.5744	104.6354	104.8560	105.0150	105.3084	105.5498
14	Amount	($)	326,272,000	330,648,000	359,656,000	385,930,000	431,975,000	475,185,000
15								
16	Light Oil							
17								
18								
19	Purchases:							
20	Units	(BBLS)	0	0	0	0	0	0
21	Unit Cost	($/BBLS)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
22	Amount	($)	0	0	0	0	0	0
23								
24	Burned:							
25	Units	(BBLS)	0	0	0	0	0	0
26	Unit Cost	($/BBLS)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
27	Amount	($)	0	0	0	0	0	0
28								
29	Ending Inventory:							
30	Units	(BBLS)	756,762	756,762	756,762	756,762	756,762	756,762
31	Unit Cost	($/BBLS)	148.8566	148.8566	148.8566	148.8566	148.8566	148.8566
32	Amount	($)	112,649,000	112,649,000	112,649,000	112,649,000	112,649,000	112,649,000
33								
34	Coal - SJRPP							
35								
36								
37	Purchases:							
38	Units	(Tons)	71,967	61,358	35,978	35,634	69,225	66,301
39	Unit Cost	($/Tons)	79.1474	79.1421	85.4689	81.8039	79.1477	79.1391
40	Amount	($)	5,696,000	4,856,000	3,075,000	2,915,000	5,479,000	5,247,000
41								
42	Burned:							
43	Units	(Tons)	71,967	61,368	35,978	35,634	69,225	66,301
44	Unit Cost	($/Tons)	79.1474	79.1421	85.4689	81.8039	79.1477	79.1391
45	Amount	($)	5,696,000	4,856,000	3,075,000	2,915,000	5,479,000	5,247,000
46								
47	Ending Inventory:							
48	Units	(Tons)	57,502	57,501	57,500	57,500	57,501	57,501
49	Unit Cost	($/Tons)	57.8241	57.8251	57.8261	57.8261	57.8251	57.8251
50	Amount	($)	3,325,000	3,325,000	3,325,000	3,325,000	3,325,000	3,325,000
51								
52	Coal - SCHERER							
53								
54								
55	Purchases:							
56	Units	(MBTU)	4,790,223	4,323,165	4,790,223	4,634,156	4,807,268	4,618,968
57	Unit Cost	($/MBTU)	2.2074	2.2104	2.2133	2.2162	2.2189	2.2219
58	Amount	($)	10,574,000	9,556,000	10,602,000	10,270,000	10,667,000	10,263,000
59								
60	Burned:							
61	Units	(MBTU)	4,790,223	4,323,165	4,790,223	4,634,156	4,807,268	4,618,968
62	Unit Cost	($/MBTU)	2.2074	2.2104	2.2133	2.2162	2.2189	2.2219
63	Amount	($)	10,574,000	9,556,000	10,602,000	10,270,000	10,667,000	10,263,000
64								
65	Ending Inventory:							
66	Units	(MBTU)	4,629,450	4,629,450	4,629,450	4,629,433	4,629,433	4,629,433
67	Unit Cost	($/MBTU)	2.1273	2.1273	2.1273	2.1273	2.1273	2.1273
68	Amount	($)	9,848,000	9,848,000	9,848,000	9,848,000	9,848,000	9,848,000
69								
70	Gas							
71								
72								
73	Burned:							
74	Units	(MCF)	31,700,096	28,726,508	36,031,375	37,366,304	43,841,163	46,121,887
75	Unit Cost	($/MCF)	11.6776	11.6799	11.4243	11.0068	10.8179	10.8268
76	Amount	($)	370,182,207	335,546,279	411,634,930	411,282,184	474,271,215	499,352,422
77								
78	Nuclear							
79								
80								
81	Burned:							
82	Units	(MBTU)	24,370,626	22,012,169	18,477,216	21,533,546	18,079,121	22,819,234
83	Unit Cost	($/MBTU)	0.4827	0.4810	0.4946	0.5077	0.5263	0.5482
84	Amount	($)	11,764,000	10,567,000	9,137,000	10,932,000	9,515,000	12,510,000

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : July 2009 thru December 2009

Line	Item	Unit	July 2009	August 2009	September 2009	October 2009	November 2009	December 2009	Total
	Heavy Oil								
1	Purchases:								
2	Units	(BBLS)	1,034,141	1,031,163	627,230	622,280	0	0	6,297,507
3	Unit Cost	($/BBLS)	108.3421	108.6433	108.7464	108.7163	0.0000	0.0000	108.1912
4	Amount	($)	112,041,000	112,029,000	68,209,000	67,652,000	0	0	681,335,000
5									
6	Burned:								
7	Units	(BBLS)	1,034,141	1,031,163	896,525	827,414	0	0	5,379,936
8	Unit Cost	($/BBLS)	108.7210	108.9834	109.1008	108.5440	0.0000	0.0000	108.1648
9	Amount	($)	112,432,885	112,379,694	97,811,563	89,810,805	-167,086	-195,424	581,919,849
10									
11	Ending Inventory:								
12	Units	(BBLS)	4,501,999	4,501,998	4,232,702	4,027,568	4,027,571	4,027,571	4,027,571
13	Unit Cost	($/BBLS)	105.5498	105.5498	105.3476	105.1769	105.1768	105.1768	105.1768
14	Amount	($)	475,186,000	475,185,000	445,905,000	423,607,000	423,607,000	423,607,000	423,607,000
15									
16	Light Oil								
17									
18									
19	Purchases:								
20	Units	(BBLS)	0	0	0	0	0	0	0
21	Unit Cost	($/BBLS)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
22	Amount	($)	0	0	0	0	0	0	0
23									
24	Burned:								
25	Units	(BBLS)	0	0	0	0	0	0	0
26	Unit Cost	($/BBLS)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
27	Amount	($)	0	0	0	0	0	0	0
28									
29	Ending Inventory:								
30	Units	(BBLS)	756,762	756,762	756,762	756,762	756,762	756,762	756,762
31	Unit Cost	($/BBLS)	148.8566	148.8566	148.8566	148.8566	148.8566	148.8566	148.8566
32	Amount	($)	112,649,000	112,649,000	112,649,000	112,649,000	112,649,000	112,649,000	112,649,000
33									
34	Coal - SJRPP								
35									
36									
37	Purchases:								
38	Units	(Tons)	70,055	71,568	66,311	71,762	68,627	69,731	758,517
39	Unit Cost	($/Tons)	81.8072	81.8103	91.7495	88.2082	91.7569	99.2959	85.0198
40	Amount	($)	5,731,000	5,855,000	6,084,000	6,330,000	6,297,000	6,924,000	64,489,000
41									
42	Burned:								
43	Units	(Tons)	70,055	71,568	66,311	71,762	68,627	69,731	758,517
44	Unit Cost	($/Tons)	81.8072	81.8103	91.7495	88.2082	91.7569	99.2959	85.0198
45	Amount	($)	5,731,000	5,855,000	6,084,000	6,330,000	6,297,000	6,924,000	64,489,000
46									
47	Ending Inventory:								
48	Units	(Tons)	57,501	57,501	57,501	57,501	57,501	57,501	57,501
49	Unit Cost	($/Tons)	57.8251	57.8251	57.8251	57.8251	57.8251	57.8251	57.8251
50	Amount	($)	3,325,000	3,325,000	3,325,000	3,325,000	3,325,000	3,325,000	3,325,000
51									
52	Coal - SCHERER								
53									
54									
55	Purchases:								
56	Units	(MBTU)	4,810,348	4,810,925	4,617,673	4,810,925	4,635,698	4,785,918	56,435,488
57	Unit Cost	($/MBTU)	2.2248	2.2276	2.2306	2.2333	2.2361	2.2391	2.2234
58	Amount	($)	10,702,000	10,717,000	10,300,000	10,744,000	10,366,000	10,716,000	125,477,000
59									
60	Burned:								
61	Units	(MBTU)	4,810,348	4,810,925	4,617,673	4,810,925	4,635,698	4,785,918	56,435,488
62	Unit Cost	($/MBTU)	2.2248	2.2276	2.2306	2.2333	2.2361	2.2391	2.2234
63	Amount	($)	10,702,000	10,717,000	10,300,000	10,744,000	10,366,000	10,716,000	125,477,000
64									
65	Ending Inventory:								
66	Units	(MBTU)	4,629,433	4,629,433	4,629,433	4,629,433	4,629,450	4,629,450	4,629,450
67	Unit Cost	($/MBTU)	2.1273	2.1273	2.1273	2.1273	2.1273	2.1273	2.1273
68	Amount	($)	9,848,000	9,848,000	9,848,000	9,848,000	9,848,000	9,848,000	9,848,000
69									
70	Gas								
71									
72									
73	Burned:								
74	Units	(MCF)	49,862,992	50,461,891	46,699,161	40,015,439	33,705,342	29,393,416	473,907,574
75	Unit Cost	($/MCF)	10.8736	10.9206	10.9771	11.2534	11.5908	12.0580	11.1907
76	Amount	($)	542,079,269	550,966,700	512,622,140	450,310,037	390,671,148	354,425,114	5,303,343,644
77									
78	Nuclear								
79									
80									
81	Burned:								
82	Units	(MBTU)	23,769,566	23,769,566	23,002,796	22,483,316	17,861,177	23,800,286	261,998,619
83	Unit Cost	($/MBTU)	0.5468	0.5449	0.5429	0.5436	0.5539	0.5909	0.5308
84	Amount	($)	12,997,000	12,953,000	12,488,000	12,222,000	9,904,000	14,063,000	139,072,000

Company: Florida Power & Light

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POWER SOLD

Estimated for the Period of : January 2009 thru December 2009

(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	254,095		254,095	6.836	8.401	17,370,970	21,347,408	3,434,011
2009	St.Lucie Rel.		46,084		46,084	0.587	0.587	270,380	270,380	0
Total			300,180	0	300,180	5.877	7.202	17,641,350	21,617,788	3,434,011
February		OS	255,749		255,749	5.423	7.018	13,870,449	17,948,708	3,547,385
2009	St.Lucie Rel.		41,625		41,625	0.585	0.585	243,300	243,300	0
Total			297,373	0	297,373	4.746	6.118	14,113,749	18,192,008	3,547,385
March		OS	171,796		171,796	7.346	8.575	12,619,435	14,731,902	1,767,209
2009	St.Lucie Rel.		46,084		46,084	0.582	0.582	268,355	268,355	0
Total			217,881	0	217,881	5.915	6.885	12,887,790	15,000,257	1,767,209
April		OS	97,896		97,896	9.395	10.632	9,197,642	10,408,493	912,002
2009	St.Lucie Rel.		43,866		43,866	0.581	0.581	254,954	254,954	0
Total			141,761	0	141,761	6.668	7.522	9,452,595	10,663,447	912,002
May		OS	64,004		64,004	10.726	12.141	6,865,212	7,770,571	765,451
2009	St.Lucie Rel.		45,332		45,332	0.579	0.579	262,456	262,456	0
Total			109,336	0	109,336	6.519	7.347	7,127,668	8,033,027	765,451
June		OS	69,716		69,716	9.756	11.141	6,801,655	7,767,121	811,740
2009	St.Lucie Rel.		43,866		43,866	0.577	0.577	253,026	253,026	0
Total			113,582	0	113,582	6.211	7.061	7,054,681	8,020,146	811,740

Company: Florida Power & Light

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POWER SOLD

Estimated for the Period of : January 2009 thru December 2009

(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	61,278		61,278	9.912	11.137	6,073,579	6,824,337	634,111
2009	St.Lucie Rel.		45,332		45,332	0.575	0.575	260,464	260,464	0
Total			106,610	0	106,610	5.941	6.646	6,334,043	7,084,801	634,111
August		OS	123,601		123,601	11.304	12.870	13,972,395	15,907,998	1,653,071
2009	St.Lucie Rel.		45,332		45,332	0.572	0.572	259,468	259,468	0
Total			168,934	0	168,934	8.425	9.570	14,231,863	16,167,466	1,653,071
September		OS	37,821		37,821	10.577	11.735	4,000,155	4,438,379	353,664
2009	St.Lucie Rel.		43,866		43,866	0.570	0.570	250,134	250,134	0
Total			81,687	0	81,687	5.203	5.740	4,250,289	4,688,513	353,664
October		OS	49,117		49,117	10.618	11.804	5,215,165	5,797,590	478,138
2009	St.Lucie Rel.		45,332		45,332	0.568	0.568	257,476	257,476	0
Total			94,449	0	94,449	5.794	6.411	5,472,641	6,055,066	478,138
November		OS	112,199		112,199	5.757	7.014	6,458,734	7,869,565	1,204,331
2009	St.Lucie Rel.		44,598		44,598	0.566	0.566	252,348	252,348	0
Total			156,796	0	156,796	4.280	5.180	6,711,083	8,121,913	1,204,331
December		OS	194,229		194,229	5.433	7.120	10,552,095	13,829,597	2,886,686
2009	St.Lucie Rel.		46,084		46,084	0.565	0.565	260,254	260,254	0
Total			240,314	0	240,314	4.499	5.863	10,812,349	14,089,850	2,886,686
Period		OS	1,491,500	0	1,491,500	7.576	9.027	112,997,486	134,641,669	18,447,799
	St.Lucie Rel.		537,402	0	537,402	0.575	0.575	3,092,615	3,092,615	0
Total			2,028,902	0	2,028,902	5.722	6.789	116,090,101	137,734,284	18,447,799

Company: Florida Power & Light

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Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2009 thru December 2009

(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)
2009 January	Sou. Co. (UPS + R)		691,300			691,300	2.709		18,727,000
	St. Lucie Rel.		39,221			39,221	0.488		191,321
	SJRPP		277,075			277,075	3.100		8,589,000
	PPAs		20,352			20,352	9.032		1,838,221
Total			1,027,948			1,027,948	2.855		29,345,542
2009 February	Sou. Co. (UPS + R)		614,819			614,819	2.709		16,655,000
	St. Lucie Rel.		35,425			35,425	0.486		172,028
	SJRPP		237,333			237,333	3.106		7,371,000
	PPAs		40,704			40,704	9.048		3,682,950
Total			928,281			928,281	3.004		27,880,979
2009 March	Sou. Co. (UPS + R)		691,904			691,904	2.709		18,743,000
	St. Lucie Rel.		39,221			39,221	0.485		190,029
	SJRPP		138,131			138,131	3.349		4,626,000
	PPAs		42,000			42,000	8.906		3,740,353
Total			911,256			911,256	2.996		27,299,381
2009 April	Sou. Co. (UPS + R)		643,607			643,607	2.709		17,435,000
	St. Lucie Rel.		32,355			32,355	0.482		156,053
	SJRPP		135,637			135,637	3.248		4,406,000
	PPAs		52,049			52,049	9.246		4,812,538
Total			863,648			863,648	3.104		26,809,590
2009 May	Sou. Co. (UPS + R)		681,847			681,847	2.709		18,471,000
	St. Lucie Rel.		0			0	0.100		0
	SJRPP		264,076			264,076	3.135		8,280,000
	PPAs		32,224			32,224	8.314		2,679,031
Total			978,147			978,147	3.009		29,430,031
2009.000000 June	Sou. Co. (UPS + R)		647,277			647,277	2.709		17,534,000
	St. Lucie Rel.		36,088			36,088	0.688		248,202
	SJRPP		251,611			251,611	3.139		7,899,000
	PPAs		22,048			22,048	8.397		1,851,411
Total			957,024			957,024	2.877		27,532,613
Period Total	Sou. Co. (UPS + R)		3,970,754			3,970,754	2.709		107,565,000
	St. Lucie Rel.		182,311			182,311	0.525		957,634
	SJRPP		1,303,863			1,303,863	3.158		41,171,000
	PPAs		209,377			209,377	8.886		18,604,503
Total			5,666,305			5,666,305	2.970		168,298,137

Company: Florida Power & Light

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Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2009 thru December 2009

(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)
2009 July	Sou. Co. (UPS + R)		685,647			685,647	2.709		18,574,000
	St. Lucie Rel.		38,577			38,577	0.686		264,458
	SJRPP		267,149			267,149	3.239		8,652,000
	PPAs		42,400			42,400	8.489		3,599,442
Total			1,033,773			1,033,773	3.007		31,089,900
2009 August	Sou. Co. (UPS + R)		691,809			691,809	2.709		18,741,000
	St. Lucie Rel.		38,577			38,577	0.683		263,610
	SJRPP		271,704			271,704	3.236		8,791,000
	PPAs		39,008			39,008	8.552		3,335,981
Total			1,041,098			1,041,098	2.990		31,131,591
2009 September	Sou. Co. (UPS + R)		650,666			650,666	2.709		17,626,000
	St. Lucie Rel.		37,333			37,333	0.680		253,890
	SJRPP		253,235			253,235	3.638		9,212,000
	PPAs		30,528			30,528	8.584		2,620,528
Total			971,762			971,762	3.058		29,712,418
2009 October	Sou. Co. (UPS + R)		691,915			691,915	2.709		18,743,000
	St. Lucie Rel.		38,577			38,577	0.678		261,491
	SJRPP		272,175			272,175	3.488		9,494,000
	PPAs		27,136			27,136	8.664		2,351,161
Total			1,029,803			1,029,803	2.996		30,849,652
2009 November	Sou. Co. (UPS + R)		665,554			665,554	2.709		18,029,000
	St. Lucie Rel.		37,956			37,956	0.676		256,458
	SJRPP		265,082			265,082	3.596		9,532,000
	PPAs		25,440			25,440	8.998		2,288,988
Total			994,032			994,032	3.029		30,106,446
2009 December	Sou. Co. (UPS + R)		679,185			679,185	2.709		18,399,000
	St. Lucie Rel.		39,221			39,221	0.673		264,144
	SJRPP		270,295			270,295	3.895		10,527,000
	PPAs		10,176			10,176	9.350		951,456
Total			998,877			998,877	3.018		30,141,600
Period Total	Sou. Co. (UPS + R)		8,035,530			8,035,530	2.709		217,677,000
	St. Lucie Rel.		412,552			412,552	0.611		2,521,684
	SJRPP		2,903,503			2,903,503	3.354		97,379,000
	PPAs		384,065			384,065	8.788		33,752,059
Total			11,735,650			11,735,650	2.994		351,329,743

Company: Florida Power & Light

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Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2009 thru December 2009

(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)
2009 January	Qual. Facilities		530,208			530,208	3.923	3.923	20,800,000
Total			530,208			530,208	3.923	3.923	20,800,000
2009 February	Qual. Facilities		472,451			472,451	3.779	3.779	17,852,000
Total			472,451			472,451	3.779	3.779	17,852,000
2009 March	Qual. Facilities		534,811			534,811	4.002	4.002	21,403,000
Total			534,811			534,811	4.002	4.002	21,403,000
2009 April	Qual. Facilities		247,750			247,750	3.917	3.917	9,704,000
Total			247,750			247,750	3.917	3.917	9,704,000
2009 May	Qual. Facilities		512,664			512,664	4.160	4.160	21,327,100
Total			512,664			512,664	4.160	4.160	21,327,100
2009 June	Qual. Facilities		505,009			505,009	4.189	4.189	21,154,893
Total			505,009			505,009	4.189	4.189	21,154,893
Period Total	Qual. Facilities		2,802,893			2,802,893	4.004	4.004	112,240,993
Total			2,802,893			2,802,893	4.004	4.004	112,240,993

Company: Florida Power & Light

Schedule: E8
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Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2009 thru December 2009

(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)
2009 July	Qual. Facilities		523,352			523,352	4.360	4.360	22,820,000
Total			523,352			523,352	4.360	4.360	22,820,000
2009 August	Qual. Facilities		507,387			507,387	4.569	4.569	23,183,000
Total			507,387			507,387	4.569	4.569	23,183,000
2009 September	Qual. Facilities		464,994			464,994	4.662	4.662	21,679,000
Total			464,994			464,994	4.662	4.662	21,679,000
2009 October	Qual. Facilities		396,984			396,984	4.961	4.961	19,694,000
Total			396,984			396,984	4.961	4.961	19,694,000
2009 November	Qual. Facilities		399,498			399,498	3.994	3.994	15,956,000
Total			399,498			399,498	3.994	3.994	15,956,000
2009 December	Qual. Facilities		477,174			477,174	4.271	4.271	20,380,000
Total			477,174			477,174	4.271	4.271	20,380,000
Period Total	Qual. Facilities		5,572,282			5,572,282	4.234	4.234	235,952,993
Total			5,572,282			5,572,282	4.234	4.234	235,952,993

Company: Florida Power & Light

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Economy Energy Purchases

Estimated For the Period of : January 2007 Thru December 2007

(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	OS	14,482	7.454	1,079,432	8.610	1,246,837	167,405
2009	Non-Florida	OS	58,322	7.664	4,469,948	8.634	5,035,283	565,335
Total			72,804	7.622	5,549,380	8.629	6,282,120	732,740
February	Florida	OS	16,189	5.029	814,143	6.882	1,114,059	299,916
2009	Non-Florida	OS	36,000	5.785	2,082,599	6.865	2,471,360	388,760
Total			52,189	5.550	2,896,743	6.870	3,585,419	688,676
March	Florida	OS	23,272	8.333	1,939,249	9.796	2,279,848	340,599
2009	Non-Florida	OS	76,800	8.390	6,443,596	9.782	7,512,507	1,068,912
Total			100,072	8.377	8,382,845	9.785	9,792,355	1,409,511
April	Florida	OS	20,288	11.172	2,266,577	12.584	2,553,046	286,469
2009	Non-Florida	OS	79,017	11.070	8,747,132	12.566	9,929,363	1,182,231
Total			99,305	11.091	11,013,710	12.570	12,482,410	1,468,700
May	Florida	OS	24,681	11.502	2,838,760	13.354	3,296,051	457,291
2009	Non-Florida	OS	89,640	12.165	10,904,960	13.237	11,865,766	960,806
Total			114,321	12.022	13,743,720	13.262	15,161,816	1,418,097
June	Florida	OS	15,858	11.679	1,852,000	13.441	2,131,463	279,463
2009	Non-Florida	OS	41,269	12.662	5,225,432	13.494	5,568,966	343,534
Total			57,127	12.389	7,077,431	13.479	7,700,429	622,997
Period	Florida	OS	114,770	9.402	10,790,161	10.997	12,621,303	1,831,142
Total	Non-Florida	OS	381,049	9.939	37,873,667	11.123	42,383,245	4,509,578
Total			495,819	9.815	48,663,828	11.094	55,004,548	6,340,720

Company: Florida Power & Light

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Economy Energy Purchases

Estimated For the Period of : January 2007 Thru December 2007

(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	OS	28,697	12.560	3,604,245	14.237	4,085,533	481,289
2009	Non-Florida	OS	48,579	13.050	6,339,793	14.330	6,961,591	621,798
Total			77,276	12.868	9,944,038	14.296	11,047,125	1,103,087
August	Florida	OS	19,175	13.159	2,523,228	14.154	2,714,019	190,791
2009	Non-Florida	OS	49,735	12.916	6,423,754	13.830	6,878,439	454,685
Total			68,910	12.984	8,946,982	13.920	9,592,458	645,476
September	Florida	OS	67,695	13.565	9,182,954	14.516	9,826,698	643,744
2009	Non-Florida	OS	64,196	12.681	8,140,843	14.045	9,016,321	875,479
Total			131,891	13.135	17,323,797	14.287	18,843,020	1,519,223
October	Florida	OS	55,711	12.421	6,919,682	14.055	7,829,936	910,253
2009	Non-Florida	OS	85,322	11.850	10,110,311	13.964	11,914,281	1,803,970
Total			141,033	12.075	17,029,993	14.000	19,744,216	2,714,223
November	Florida	OS	46,917	5.525	2,592,346	6.633	3,112,147	519,801
2009	Non-Florida	OS	97,696	5.415	5,290,714	6.611	6,459,112	1,168,399
Total			144,613	5.451	7,883,060	6.619	9,571,260	1,688,199
December	Florida	OS	44,830	4.879	2,187,275	6.451	2,891,984	704,710
2009	Non-Florida	OS	91,628	4.696	4,302,972	6.454	5,913,771	1,610,799
Total			136,458	4.756	6,490,247	6.453	8,805,755	2,315,508
Period	Florida	OS	377,794	10.005	37,799,891	11.403	43,081,621	5,281,730
Total	Non-Florida	OS	818,206	9.592	78,482,053	10.942	89,526,761	11,044,708
Total			1,196,000	9.723	116,281,945	11.088	132,608,382	16,326,437

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	CURRENT AUG 08 - DEC 08	PRELIMINARY JAN 09 - MAY 09	DIFFERENCE $	DIFFERENCE %	PRELIMINARY JUNE 09 - OCT 09	DIFFERENCE $	DIFFERENCE %	PRELIMINARY NOV 09 - DEC 09	DIFFERENCE $	DIFFERENCE %
BASE	$39.37	$39.31	($0.06)	-0.15%	$40.72	$1.41	3.59%	$42.00	$1.28	3.14%
FUEL	$60.21	$64.13	$3.92	6.51%	$62.72	($1.41)	-2.20%	$61.44	($1.28)	-2.04%
CONSERVATION	$1.45	$2.04	$0.59	40.69%	$2.04	$0.00	0.00%	$2.04	$0.00	0.00%
CAPACITY PAYMENT	$5.46	$8.55	$3.09	56.59%	$8.55	$0.00	0.00%	$8.55	$0.00	0.00%
ENVIRONMENTAL	$0.40	$0.94	$0.54	135.00%	$0.94	$0.00	0.00%	$0.94	$0.00	0.00%
STORM RESTORATION SURCHARGE	$1.11	$1.45 *	$0.34	30.63%	$1.45	$0.00	0.00%	$1.45	$0.00	0.00%
SUBTOTAL	$108.00	$116.42	$8.42	7.80%	$116.42	$0.00	0.00%	$116.42	$0.00	0.00%
GROSS RECEIPTS TAX	$2.77	$2.99	$0.22	7.94%	$2.99	$0.00	0.00%	$2.99	$0.00	0.00%
TOTAL	$110.77	$119.41	$8.64	7.80%	$119.41	$0.00	0.00%	$119.41	$0.00	0.00%

* Storm Charge effective November 1, 2008

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL	ACTUAL	ESTIMATED/ACTUAL	PROJECTED			
		JAN - DEC 2006 - 2006 (COLUMN 1)	JAN - DEC 2007 - 2007 (COLUMN 2)	JAN - DEC 2008 - 2008 (COLUMN 3)	JAN - DEC 2009-2009 (COLUMN 4)	(COLUMN 2) / (COLUMN 1)	(COLUMN 3) / (COLUMN 2)	(COLUMN 4) / (COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	792,923,918	924,098,845	663,091,982	617,755,849	16.5	(28.2)	(6.8)
2	LIGHT OIL	3,022,019	5,521,841	2,832,929	0	82.7	(48.7)	(100.0)
3	COAL	130,166,710	149,683,170	156,818,588	190,200,000	15.0	4.8	21.3
4	GAS	3,988,536,281	4,473,222,671	5,307,779,635	5,310,555,644	12.2	18.7	0.1
5	NUCLEAR	96,843,144	91,245,401	111,653,216	141,654,000	(5.8)	22.4	26.9
6	OTHER	0	0	0	0	0.0	0.0	0.0
7	TOTAL ($)	5,011,482,072	5,643,771,728	6,242,178,330	6,260,165,493	12.6	10.6	0.3
	SYSTEM NET GENERATION							
8	HEAVY OIL	9,585,826	9,651,216	5,900,534	3,715,276	0.7	(38.9)	(37.0)
9	LIGHT OIL	25,951	27,033	14,410	0	4.2	(46.7)	(100.0)
10	COAL	6,168,129	6,855,626	6,599,540	7,277,030	11.1	(3.7)	10.3
11	GAS	56,965,272	59,300,494	61,380,716	63,290,754	4.1	3.5	3.1
12	NUCLEAR	23,532,578	21,899,288	23,804,145	24,010,237	(6.9)	8.7	0.9
13	OTHER	0	0	0	0	0.0	0.0	0.0
14	TOTAL (MWH)	96,297,756	97,733,657	97,699,445	98,293,297	1.5	(0.04)	0.6
	UNITS OF FUEL BURNED							
15	HEAVY OIL (Bbl)	15,296,754	15,523,650	9,025,279	5,710,861	1.5	-41.86	(36.7)
16	LIGHT OIL (Bbl)	39,600	114,332	31,379	0	188.7	-72.55	(100.0)
17	COAL (TON)	749,567	803,110	765,182	760,629	7.1	-4.72	(0.6)
18	GAS (MCF)	437,700,179	447,353,401	468,525,901	474,579,592	2.2	4.73	1.3
19	NUCLEAR (MMBTU)	257,691,698	240,216,287	259,208,670	267,643,738	(6.8)	7.91	3.3
20	OTHER (TONS)	0	0	0	0	0.0	0.0	0.0
	BTU'S BURNED (MMBTU)							
21	HEAVY OIL	97,243,909	99,303,877	60,591,637	36,549,503	2.1	(39.0)	(39.7)
22	LIGHT OIL	217,781	381,540	180,303	0	75.2	(52.7)	(100.0)
23	COAL	64,066,268	70,529,786	68,253,838	75,530,252	10.1	(3.2)	10.7
24	GAS	452,949,944	461,001,723	475,966,620	474,579,592	1.8	3.2	(0.3)
25	NUCLEAR	257,691,698	240,216,287	259,208,670	267,643,738	(6.8)	7.9	3.3
26	OTHER	0	0	0	0	0.0	0.0	0.0
27	TOTAL (MMBTU)	872,169,620	871,433,213	864,201,068	854,303,085	(0.1)	(0.8)	(1.2)
	GENERATION MIX (%MWH)							
28	HEAVY OIL	9.95	9.88	6.04	3.78%	-	-	-
29	LIGHT OIL	0.03	0.03	0.01	0.00%	-	-	-
30	COAL	6.41	7.01	6.75	7.40%			
31	GAS	59.16	60.68	62.83	64.39%	-	-	-
32	NUCLEAR	24.44	22.41	24.36	24.43%	-	-	-
33	OTHER	-	-	-	0.00%	-	-	-
34	TOTAL (%)	100.00	100.00	100.00	100.00%	-	-	-
	FUEL COST PER UNIT							
35	HEAVY OIL ($/Bbl)	51.8361	59.5285	73.4705	108.1721	14.8	23.4	47.2
36	LIGHT OIL ($/Bbl)	76.3139	48.2949	90.2810	0.0000	(36.7)	86.9	(100.0)
37	COAL ($/TON)	47.8288	52.4253	72.2637	47.7000	9.6	37.8	(34.0)
38	GAS ($/MCF)	9.1125	9.9993	11.3287	11.1900	9.7	13.3	(1.2)
39	NUCLEAR ($/MMBTU)	0.3758	0.3798	0.4307	0.5293	1.1	13.4	22.9
40	OTHER ($/TON)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL	8.1540	9.3058	10.9436	16.9019	14.1	17.6	54.5
42	LIGHT OIL	13.8764	14.472	15.7120	0.0000	4.3	8.6	(100.0)
43	COAL	2.0310	2.1223	2.2976	2.5182	4.5	8.3	9.6
44	GAS	8.8057	9.7033	11.1516	11.1900	10.2	14.9	0.3
45	NUCLEAR	0.3758	0.3798	0.4307	0.5293	1.1	13.4	22.9
46	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
47	TOTAL ($/MMBTU)	5.7459	6.4764	7.2231	7.3278	12.7	11.5	1.5
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	10,145	10,289	10,269	9,838	1.4	(0.2)	(4.2)
49	LIGHT OIL	8,392	14,114	12,512	0	68.2	(11.3)	(100.0)
50	COAL	10,390	10,288	10,342	10,379	(1.0)	0.5	0.4
51	GAS	7,949	7,774	7,754	7,498	(2.2)	(0.3)	(3.3)
52	NUCLEAR	10,950	10,969	10,889	11,147	0.2	(0.7)	2.4
53	OTHER	0	0	0	0	0.0	0.0	0.0
54	TOTAL (BTU/KWH)	9,057	8,916	8,846	8,691	(1.6)	(0.8)	(1.8)
	GENERATED FUEL COST PER KWH (c/KWH)							
55	HEAVY OIL	8.2718	9.5749	11.2378	16.6275	15.8	17.4	48.0
56	LIGHT OIL	11.6453	20.4256	19.6595	0.0000	75.4	(3.8)	(100.0)
57	COAL	2.1101	2.1834	2.3762	2.6137	3.5	8.8	10.0
58	GAS	6.9992	7.5433	8.6473	8.3907	7.8	14.6	(3.0)
59	NUCLEAR	0.4115	0.4167	0.4690	0.5900	1.3	12.6	25.8
60	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
61	TOTAL (c/KWH)	5.2042	5.7746	6.3892	6.3689	11.0	10.6	(0.3)

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

(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 .0048¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1, 2008 – March 31, 2009	8.20	6.42	6.96
April 1, 2009 – September 30, 2009	11.68	10.91	11.14
October 1, 2009 – March 31, 2010	7.89	6.47	6.91
April 1, 2010 – September 30, 2010	11.86	10.68	11.04

A MW block size ranging from 58 MW to 65 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	1.0204
Secondary Voltage Delivery	1.0444

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
2009	20	3	57	6	14	.63	13.35	10.24	2.30
2010	18	4	61	6	11	.71	14.54	9.71	2.31
2011	18	1	67	6	8	.77	12.43	8.54	2.16
2012	19	1	66	5	8	.79	12.46	8.58	2.15
2013	20	0	66	5	8	.81	11.62	7.81	2.18
2014	19	0	68	5	8	.83	11.90	8.21	2.23
2015	18	0	69	5	8	.85	12.17	8.52	2.74
2016	18	0	73	5	3	.88	12.89	8.93	2.78
2017	18	0	74	5	3	.90	12.32	9.32	2.82
2018	21	1	71	4	3	.91	14.10	9.72	2.86

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

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.102)

Customer Rate Schedule	Charge($)	Customer Rate Schedule	Charge($)
GS-1	8.51	CST-1	104.04
GST-1	11.64	GSLD-2	160.77
GSD-1	33.10	GSLDT-2	160.77
GSDT-1	39.24	CS-2	160.77
RS-1	5.34	CST-2	160.77
RST-1	8.47	GSLD-3	378.28
GSLD-1	38.78	CS-3	378.28
GSLDT-1	38.78	CST-3	378.28
CS-1	104.04	GSLDT-3	378.28

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	0.171%
Distribution Equipment	0.237%
Transmission Equipment	0.123%

D. **Taxes and Assessments**

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

TERMS OF SERVICE

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

(Continue on Sheet No. 10.104)

APPENDIX III

CAPACITY COST RECOVERY

KMD-6
DOCKET NO. 080001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT ________
PAGES 1-7
SEPTEMBER 2, 2008

APPENDIX III
CAPACITY COST RECOVERY

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FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
JANUARY 2009 THROUGH DECEMBER 2009

	PROJECTED												
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. CAPACITY PAYMENTS TO NON-COGENERATORS	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$223,732,036
2. SHORT TERM CAPACITY PAYMENTS	3,933,560	4,117,810	3,490,284	3,643,864	3,495,364	4,454,740	4,454,740	4,454,740	4,454,740	3,495,364	3,495,364	3,829,060	$47,319,630
3. CAPACITY PAYMENTS TO COGENERATORS	$27,667,653	$27,667,653	$27,667,653	$27,667,653	$27,667,653	$27,667,653	$27,667,653	$25,419,531	$25,419,531	$25,419,531	$25,419,531	$25,419,531	$320,771,227
4. SJRPP SUSPENSION ACCRUAL	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$2,405,832
5. RETURN REQUIREMENTS ON SJRPP SUSPENSION LIABILITY	($463,915)	($465,769)	($467,623)	($469,477)	($471,331)	($473,186)	($475,040)	($476,894)	($478,748)	($480,602)	($482,456)	($484,310)	($5,689,352)
6. INCREMENTAL PLANT SECURITY COSTS	$ 2,615,962	$ 2,618,791	$ 2,622,187	$ 2,619,644	$ 2,616,826	$ 2,617,190	$ 2,616,746	$ 2,617,210	$ 2,622,330	$ 2,617,683	$ 2,618,111	$ 2,636,580	$31,439,262
7. TRANSMISSION OF ELECTRICITY BY OTHERS	207,880	219,336	206,670	192,819	599,562	600,275	590,775	591,986	584,863	177,681	185,181	197,626	$4,354,655
8. TRANSMISSION REVENUES FROM CAPACITY SALES	(542,427)	(530,874)	(345,258)	(298,850)	(139,908)	(153,726)	(116,647)	(282,532)	(84,560)	(104,287)	(206,499)	(390,816)	($3,196,384)
9. SYSTEM TOTAL	$52,263,536	$52,471,771	$52,018,735	$52,200,475	$52,612,988	$53,557,770	$53,583,049	$51,168,863	$51,362,979	$49,970,193	$49,874,054	$50,052,493	$621,136,906
10. JURISDICTIONAL % *													98.76729%
11. JURISDICTIONALIZED CAPACITY PAYMENTS													$613,480,089
12. SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
13. 2007 FINAL TRUE-UP -- overrecovery/(underrecovery) ($3,707,455)			2008 EST \ ACT TRUE-UP -- overrecovery/(underrecovery) ($26,832,716)										($30,540,170)
14. NUCLEAR COST RECOVERY - TOTAL COST													$258,406,183
15. Turkey Point Unit 5 GBRA True-Up													($9,296,089)
16. TOTAL (Lines 10+11+12+13+14)													$836,184,761
17. REVENUE TAX MULTIPLIER													1.00072
18. TOTAL RECOVERABLE CAPACITY PAYMENTS													$836,786,814

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN.(MW)	%
FPSC	18,436	98.76729%
FERC	230	1.23271%
TOTAL	18,666	100.00000%

* BASED ON 2007 ACTUAL DATA

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2008

LINE NO.		(1) ACTUAL JAN 2008	(2) ACTUAL FEB 2008	(3) ACTUAL MAR 2008	(4) ACTUAL APR 2008	(5) ACTUAL MAY 2008	(6) ACTUAL JUN 2008
1.	Payments to Non-cogenerators (UPS & SJRPP)	$16,441,906	$15,931,274	$17,621,045	$17,557,000	$17,177,245	$16,300,100
2.	Short-Term Capacity Purchases CCR	4,023,700	4,023,700	3,550,815	3,572,590	3,572,590	4,513,750
3.	QF Capacity Charges	27,397,913	26,863,012	27,042,396	26,627,952	27,067,859	27,436,774
4a.	SJRPP Suspension Accrual	294,744	106,228	200,486	200,486	200,486	200,486
4b.	Return on SJRPP Suspension Liability	(442,101)	(443,955)	(445,373)	(447,227)	(449,081)	(450,935)
5.	Okeelanta Settlement (Capacity)	0	0	0	0	0	0
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	1,452,104	1,932,592	2,453,342	1,926,590	1,877,587	2,015,843
7.	Transmission of Electricity by Others	529,163	539,869	720,134	619,914	612,094	600,189
8.	Transmission Revenues from Capacity Sales	(583,059)	(477,977)	(275,441)	(135,249)	(171,448)	(296,626)
9.	Total (Lines 1 through 8)	$ 49,114,371	$ 48,474,744	$ 50,867,403	$ 49,922,055	$ 49,887,332	$ 50,319,580
10.	Jurisdictional Separation Factor (a)	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%
11.	Jurisdictional Capacity Charges	48,505,588	47,873,889	50,236,891	49,303,262	49,268,969	49,695,859
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)
13.	Jurisdictional Capacity Charges Authorized	$ 43,760,122	$ 43,128,423	$ 45,491,425	$ 44,557,796	$ 44,523,503	$ 44,950,393
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 41,500,197	$ 37,558,428	$ 37,683,136	$ 38,849,864	$ 42,225,337	$ 48,534,965
15.	Prior Period True-up Provision	(1,632,608)	(1,632,608)	(1,632,608)	(1,632,608)	(1,632,608)	(1,632,608)
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 39,867,590	$ 35,925,820	$ 36,050,529	$ 37,217,256	$ 40,592,729	$ 46,902,357
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(3,892,533)	(7,202,603)	(9,440,896)	(7,340,539)	(3,930,773)	1,951,964
18.	Interest Provision for Month	(82,039)	(73,077)	(83,863)	(95,795)	(101,289)	(92,692)
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(19,591,292)	(21,933,256)	(27,576,328)	(35,468,480)	(41,272,207)	(43,671,662)
20.	Deferred True-up - Over/(Under) Recovery	(3,707,455)	(3,707,455)	(3,707,455)	(3,707,455)	(3,707,455)	(3,707,455)
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	1,632,608	1,632,608	1,632,608	1,632,608	1,632,608	1,632,608
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (25,640,711)	$ (31,283,783)	$ (39,175,935)	$ (44,979,662)	$ (47,379,117)	$ (43,887,237)
		(2,341,963.83)	(5,643,072.50)	(7,892,152.01)	(5,803,726.31)	(2,399,455.11)	3,491,880.19

Notes: **(a) Per K. M. Dubin's Testimony Appendix III Page 3, filed September 1, 2006**
(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.

3a

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2008

LINE NO.		(7) ACTUAL JUL 2008	(8) ESTIMATED AUG 2008	(9) ESTIMATED SEP 2008	(10) ESTIMATED OCT 2008	(11) ESTIMATED NOV 2008	(12) ESTIMATED DEC 2008	(13) TOTAL	LINE NO.
1.	Payments to Non-cogenerators (UPS & SJRPP)	$15,841,542	$17,003,360	$17,003,360	$17,003,360	$17,003,360	$17,003,360	$201,886,913	1.
2.	Short-Term Capacity Purchases CCR	4,464,250	4,554,010	4,554,010	3,441,144	3,441,144	3,884,330	47,596,033	2.
3.	QF Capacity Charges	27,462,232	26,968,428	26,968,428	26,968,428	26,968,428	26,968,428	324,740,277	3.
4a.	SJRPP Suspension Accrual	200,486	200,486	200,486	200,486	200,486	200,486	2,405,832	4a.
4b.	Return on SJRPP Suspension Liability	(452,790)	(454,644)	(456,498)	(458,352)	(460,206)	(462,060)	(5,423,221)	4b.
5.	Okeelanta Settlement (Capacity)	0	0	0	0	0	0	0	5.
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	1,637,559	3,294,566	3,294,566	3,294,566	3,294,566	3,294,566	29,768,444	6.
7.	Transmission of Electricity by Others	582,872	490,600	478,989	490,561	498,061	510,506	6,672,953	7.
8.	Transmission Revenues from Capacity Sales	(80,521)	(273,580)	(83,690)	(113,906)	(251,705)	(573,519)	(3,316,722)	8.
9.	Total (Lines 1 through 8)	$ 49,655,630	$ 51,783,226	$ 51,959,651	$ 50,826,287	$ 50,694,134	$ 50,826,097	$ 604,330,509	9.
10.	Jurisdictional Separation Factor (a)	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	N/A	10.
11.	Jurisdictional Capacity Charges	49,040,139	51,141,363	51,315,601	50,196,285	50,065,770	50,196,097	596,839,712	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(56,945,592)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 44,294,673	$ 46,395,897	$ 46,570,135	$ 45,450,819	$ 45,320,304	$ 45,450,631	$ 539,894,120	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 48,367,588	$ 52,796,672	$ 51,343,319	$ 48,893,886	$ 43,695,958	$ 42,122,639	$ 533,571,989	14.
15.	Prior Period True-up Provision	(1,632,608)	(1,632,608)	(1,632,608)	(1,632,608)	(1,632,608)	(1,632,608)	(19,591,292)	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 46,734,980	$ 51,164,064	$ 49,710,711	$ 47,261,278	$ 42,063,350	$ 40,490,031	$ 513,980,697	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	2,440,307	4,768,168	3,140,577	1,810,460	(3,256,953)	(4,960,600)	(25,913,423)	17.
18.	Interest Provision for Month	(85,271)	(74,620)	(63,412)	(55,188)	(53,451)	(58,595)	(919,293)	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(40,179,782)	(36,192,138)	(29,865,983)	(25,156,211)	(21,768,332)	(23,446,129)	(19,591,292)	19.
20.	Deferred True-up - Over/(Under) Recovery	(3,707,455)	(3,707,455)	(3,707,455)	(3,707,455)	(3,707,455)	(3,707,455)	(3,707,455)	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	1,632,608	1,632,608	1,632,608	1,632,608	1,632,608	1,632,608	19,591,292	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (39,899,593)	$ (33,573,438)	$ (28,863,666)	$ (25,475,787)	$ (27,153,584)	$ (30,540,170)	$ (30,540,170)	22.
		3,987,643.72	6,326,154.97	4,709,772.18	3,387,879.13	(1,677,797.04)	(3,386,586.70)		

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, filed September 4, 2007.
(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.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2009 THROUGH DECEMBER 2009

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	65.077%	55,403,306,419	9,718,567	1.08663620	1.06901375	59,226,896,463	10,560,547	52.33820%	56.97040%
GS1/GST1	64.480%	6,219,248,803	1,101,055	1.08663620	1.06901375	6,648,462,497	1,196,446	5.87518%	6.45440%
GSD1/GSDT1/HLFT1 (21-499 kW)	76.435%	24,942,068,687	3,725,073	1.08655195	1.06894858	26,661,788,803	4,047,485	23.56075%	21.83474%
OS2	95.627%	18,498,130	2,208	1.05506701	1.04443473	19,320,090	2,330	0.01707%	0.01257%
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	81.083%	11,220,287,833	1,579,680	1.08535318	1.06805030	11,983,831,786	1,714,511	10.58999%	9.24918%
GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	89.478%	2,133,689,890	272,215	1.07696203	1.06151341	2,264,940,431	293,165	2.00150%	1.58152%
GSLD3/GSLDT3/CS3/CST3	93.476%	261,545,665	31,941	1.02836156	1.02355239	267,705,691	32,847	0.23657%	0.17720%
ISST1D	111.786%	0	0	1.05506701	1.04443473	0	0	0.00000%	0.00000%
ISST1T	111.422%	0	0	1.02836156	1.02355239	0	0	0.00000%	0.00000%
SST1T	111.422%	87,048,226	8,918	1.02836156	1.02355239	89,098,420	9,171	0.07874%	0.04947%
SST1D1/SST1D2/SST1D3	111.786%	5,382,413	550	1.05506701	1.04443473	5,621,580	580	0.00497%	0.00313%
CILC D/CILC G	92.489%	3,419,610,773	422,070	1.07580614	1.06089603	3,627,851,508	454,065	3.20589%	2.44952%
CILC T	93.565%	1,493,300,492	182,193	1.02836156	1.02355239	1,528,471,292	187,360	1.35069%	1.01074%
MET	72.366%	91,941,054	14,503	1.05506701	1.04443473	96,026,431	15,302	0.08486%	0.08255%
OL1/SL1/PL1	653.334%	584,472,455	10,212	1.08663620	1.06901375	624,809,092	11,097	0.55214%	0.05986%
SL2, GSCU1	113.244%	109,513,160	11,039	1.08663620	1.06901375	117,071,074	11,995	0.10345%	0.06471%
TOTAL		105,989,914,000	17,080,224			113,161,895,158	18,536,901	100.00%	100.00%

(1) AVG 12 CP load factor based on actual calendar data.
(2) Projected kwh sales for the period January 2009 through December 2009.
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 2007 demand losses.
(5) Based on 2007 energy losses.
(6) Col(2) * Col(5).
(7) Col(3) * Col(4).
(8) Col(6) / total for Col(6)
(9) Col(7) / total for Col(7)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
JANUARY 2009 THROUGH DECEMBER 2009

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	52.33820%	56.97040%	$33,689,164	$440,049,979	$473,739,143	55,403,306,419	-	-	-	0.00855
GS1/GST1/WIES1	5.87518%	6.45440%	$3,781,747	$49,854,997	$53,636,744	6,219,248,803	-	-	-	0.00862
GSD1/GSDT1/HLFT1 (21-499 kW)	23.56075%	21.83474%	$15,165,633	$168,655,628	$183,821,261	24,942,068,687	47.36064%	72,142,643	2.55	-
OS2	0.01707%	0.01257%	$10,990	$97,089	$108,079	18,498,130	-	-	-	0.00584
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	10.58999%	9.24918%	$6,816,587	$71,442,372	$78,258,959	11,220,287,833	62.66433%	24,527,921	3.19	-
GSLD2/GSLDT2/CS2/CST2/HLFT3 (2,000+ kW)	2.00150%	1.58152%	$1,288,333	$12,215,963	$13,504,296	2,133,689,890	68.48888%	4,267,646	3.16	-
GSLD3/GSLDT3/CS3/CST3	0.23657%	0.17720%	$152,275	$1,368,710	$1,520,985	261,545,665	76.00256%	471,407	3.23	-
ISST1D	0.00000%	0.00000%	$0	$0	$0	0	41.32527%	0	**	-
ISST1T	0.00000%	0.00000%	$0	$0	$0	0	11.39886%	0	**	-
SST1T	0.07874%	0.04947%	$50,681	$382,149	$432,830	87,048,226	11.39886%	1,046,106	**	-
SST1D1/SST1D2/SST1D3	0.00497%	0.00313%	$3,198	$24,168	$27,368	5,382,413	41.32527%	17,842	**	-
CILC D/CILC G	3.20589%	2.44952%	$2,063,577	$18,920,544	$20,984,121	3,419,610,773	74.45869%	6,291,271	3.34	-
CILC T	1.35069%	1.01074%	$869,418	$7,807,149	$8,676,567	1,493,300,492	75.82759%	2,697,721	3.22	-
MET	0.08486%	0.08255%	$54,621	$637,623	$692,244	91,941,054	60.06395%	209,688	3.30	-
OL1/SL1/PL1	0.55214%	0.05986%	$355,401	$462,404	$817,805	584,472,455	-	-	-	0.00140
SL2/GSCU1	0.10345%	0.06471%	$66,592	$499,823	$566,415	109,513,160	-	-	-	0.00517
TOTAL			$64,368,217	$772,418,597	$836,786,814	105,989,914,000		111,672,245		

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 2009 through December 2009
(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) = (Total col 5)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

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

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
ISST1D	$0.40	$0.19
ISST1T	$0.39	$0.18
SST1T	$0.39	$0.18
SST1D1/SST1D2/SST1D3	$0.40	$0.19

Florida Power & Light Company
Schedule E12 - Capacity Costs

For the Year 2009

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
Palm Beach Solid Waste Authority	50	4/1/1992	3/31/2010	QF
Broward North - 1987 Agreement	45	4/1/1992	12/31/2010	QF
Broward North - 1991 Agreement	11	1/1/1993	12/31/2026	QF
Broward South - 1987 Agreement	50.6	4/1/1991	8/1/2009	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF
Southern Co. - UPS	931	7/20/1988	5/31/2010	UPS
JEA - SJRPP	375	4/2/1982	9/30/2021	JEA

QF = Qualifying Facility
UPS= Unit Power Sales Agreement with Southern Company
JEA = SJRPP Purchased Power Agreements

2009 Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	10,413,958	10,413,958	10,413,958	10,413,958	10,413,958	10,413,958	10,413,958	10,413,958	10,413,958	10,413,958	10,413,958	10,413,958	124,967,500
ICL	10,417,923	10,417,923	10,417,923	10,417,923	10,417,923	10,417,923	10,417,923	10,417,923	10,417,923	10,417,923	10,417,923	10,417,923	125,015,074
SWAPBC	2,298,750	2,298,750	2,298,750	2,298,750	2,298,750	2,298,750	2,298,750	2,298,750	2,298,750	2,298,750	2,298,750	2,298,750	27,585,000
BN-SOC	2,018,138	2,018,138	2,018,138	2,018,138	2,018,138	2,018,138	2,018,138	2,018,138	2,018,138	2,018,138	2,018,138	2,018,138	24,217,650
BN-NEG	292,600	292,600	292,600	292,600	292,600	292,600	292,600	292,600	292,600	292,600	292,600	292,600	3,511,200
BS-SOC	2,248,122	2,248,122	2,248,122	2,248,122	2,248,122	2,248,122	2,248,122	0	0	0	0	0	15,736,853
BS-NEG	93,100	93,100	93,100	93,100	93,100	93,100	93,100	93,100	93,100	93,100	93,100	93,100	1,117,200
SoCo	11,965,552	11,965,552	11,965,552	11,965,552	11,965,552	11,965,552	11,965,552	11,965,552	11,965,552	11,965,552	11,965,552	11,965,552	143,586,622
SJRPP	6,678,785	6,678,785	6,678,785	6,678,785	6,678,785	6,678,785	6,678,785	6,678,785	6,678,785	6,678,785	6,678,785	6,678,785	80,145,414
Total	46,426,927	46,426,927	46,426,927	46,426,927	46,426,927	46,426,927	46,426,927	44,178,805	44,178,805	44,178,805	44,178,805	44,178,805	545,882,513

Florida Power & Light Company
Docket No. 080001-EI
Schedule E12
Page 2 of 2

Contract	Counterparty	Identification	Contract End Date
1	Southern Company (Oleander)	Other Entity	May 31, 2012
2	Reliant Energy Services (Indian River)	Other Entity	December 31, 2009
3	Bear Energy, LP	Other Entity	December 31, 2009
4	Constellation Energy Commodities Group, Inc.	Other Entity	April 30, 2009

Capacity in MW

Contract	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
1	158	158	158	158	158	158	158	158	158	158	158	158
2	567	567	567	567	567	567	567	567	567	567	567	567
3	106	106	105	106	106	106	106	106	106	106	106	106
4	38	105	-	54	-	-	-	-	-	-	-	-
Total	869	936	830	885	831	831	831	831	831	831	831	831

Capacity in Dollars

Contract	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
1	[redacted]											
2	[redacted]											
3	[redacted]											
4	[redacted]											
Total	3,933,560	4,117,810	3,490,284	3,643,864	3,495,364	4,454,740	4,454,740	4,454,740	4,454,740	3,495,364	3,495,364	3,829,060

Total Short Term Capacity Payments for 2009	47,319,630	(1)

(1) September 2, 2008 Projection Filing, Appendix III, page 3, line 2

APPENDIX IV

FUEL COST RECOVERY –
NON-LEVELIZED BILL

E SCHEDULES

KMD-7
DOCKET NO. 080001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT ________
PAGES 1-8
SEPTEMBER 2, 2008

APPENDIX IV

FUEL COST RECOVERY – NON-LEVELIZED BILL

E SCHEDULES
January 2009 – December 2009

TABLE OF CONTENTS

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2009 -DECEMBER 2009

		(a)	(b)	(c)
		DOLLARS	MWH	¢/KWH
1	Fuel Cost of System Net Generation (E3)	$6,214,273,493	97,654,973	6.3635
2	Nuclear Fuel Disposal Costs (E2)	21,828,572	23,509,501	0.0929
3	Fuel Related Transactions (E2)	2,611,519	0	0.0000
4	Incremental Hedging Costs (E2)	694,510	0	
5	Fuel Cost of Sales to FKEC / CKW (E2)	(76,920,848)	(1,046,781)	7.3483
6	TOTAL COST OF GENERATED POWER	$6,162,487,245	96,608,192	6.3788
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	351,329,743	11,735,650	2.9937
8	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	37,799,891	377,794	10.0054
9	Energy Cost of Other Econ Purch (Non-Florida) (E9)	78,482,053	818,206	9.5920
10	Payments to Qualifying Facilities (E8)	235,952,993	5,572,282	4.2344
11	TOTAL COST OF PURCHASED POWER	$703,564,680	18,503,933	3.8022
12	TOTAL AVAILABLE KWH (LINE 6 + LINE 11)		115,112,124	
13	Fuel Cost of Economy Sales (E6)	(112,997,486)	(1,491,500)	7.5761
14	Gain on Economy Sales (E6)	(18,447,799)	(2,028,902)	0.9093
15	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(3,092,615)	(537,402)	0.5755
16	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
17	TOTAL FUEL COST AND GAINS OF POWER SALES	($134,537,900)	(2,028,902)	6.6311
18	Net Inadvertent Interchange	0	0	
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 6 + 11 + 17)	$6,731,514,025	113,083,222	5.9527
20	Net Unbilled Sales	(43,628,792) **	(732,923)	(0.0411)
21	Company Use	20,194,542 **	339,250	0.0190
22	T & D Losses	437,548,412 **	7,350,409	0.4123
23	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$6,731,514,025	106,126,486	6.3429
24	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$8,662,785	136,572	6.3429
25	Jurisdictional MWH Sales	$6,722,851,240	105,989,914	6.3429
26	Jurisdictional Loss Multiplier	-	-	1.00056
27	Jurisdictional MWH Sales Adjusted for Line Losses	$6,726,616,037	105,989,914	6.3465
28	FINAL TRUE-UP Jan 07- Dec 07 (a) — EST/ACT TRUE-UP Jan 08 - Dec 08 $296,048.402 underrecovery	296,048,402	105,989,914	0.2793
29	TOTAL JURISDICTIONAL FUEL COST	$7,022,664,439	105,989,914	6.6258
30	Revenue Tax Factor			1.00072
31	Fuel Factor Adjusted for Taxes	7,027,720,757		6.6306
32	GPIF ***	$5,383,572	105,989,914	0.0051
33	Fuel Factor including GPIF (Line 32 + Line 33)	7,033,104,329	105,989,914	6.6357
34	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			6.636

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

(a) 2007 Final True-Up under-recovery of $121,036,106 included in August -December 2008 mid-course correction factor

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2009 - DECEMBER 2009

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	31.07	34.90
OFF PEAK	68.93	65.10
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$6,731,514,025	$2,349,379,583	$4,382,134,442
2	MWH SALES	106,126,486	32,978,092	73,148,394
3	COST PER KWH SOLD	6.3429	7.1241	5.9907
4	JURISDICTIONAL LOSS FACTOR	1.00056	1.00056	1.00056
5	JURISDICTIONAL FUEL FACTOR	6.3465	7.1281	5.9941
6	TRUE-UP	0.2793	0.2793	0.2793
7				
8	TOTAL	6.6258	7.4074	6.2734
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	6.6306	7.4127	6.2779
11	GPIF	0.0051	0.0051	0.0051
12	RECOVERY FACTOR including GPIF	6.6357	7.4178	6.2830
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	6.636	7.418	6.283

HOURS:		
	ON-PEAK	24.74 %
	OFF-PEAK	75.26 %

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E
Page 1 of 2

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

JANUARY 2009 - DECEMBER 2009

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh		6.636	1.00183	6.305
	all additional kWh		6.636	1.00183	7.305
A	GS-1, SL-2, GSCU-1, WIES-1		6.636	1.00183	6.648
A-1*	SL-1, OL-1, PL-1		6.465	1.00183	6.477
B	GSD-1		6.636	1.00178	6.648
C	GSLD-1 & CS-1		6.636	1.00078	6.641
D	GSLD-2, CS-2, OS-2 & MET		6.636	0.99318	6.590
E	GSLD-3 & CS-3		6.636	0.95923	6.365
A	RST-1, GST-1	ON-PEAK	7.418	1.00183	7.431
		OFF-PEAK	6.283	1.00183	6.295
B	GSDT-1, CILC-1(G),	ON-PEAK	7.418	1.00177	7.431
	HLFT-1 (21-499 kW)	OFF-PEAK	6.283	1.00177	6.294
C	GSLDT-1, CST-1,	ON-PEAK	7.418	1.00093	7.425
	HLFT-2 (500-1,999 kW)	OFF-PEAK	6.283	1.00093	6.289
D	GSLDT-2, CST-2,	ON-PEAK	7.418	0.99481	7.379
	HLFT-3 (2,000+)	OFF-PEAK	6.283	0.99481	6.250
E	GSLDT-3,CST-3,	ON-PEAK	7.418	0.95923	7.115
	CILC -1(T) & ISST-1(T)	OFF-PEAK	6.283	0.95923	6.027
F	CILC -1(D) &	ON-PEAK	7.418	0.99371	7.371
	ISST-1(D)	OFF-PEAK	6.283	0.99371	6.243

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

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2009 - DECEMBER 2009

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$407,161,518	$360,159,134	$436,696,407	$459,222,843	$569,090,084	$593,429,664	$2,825,759,649	A1
1a	NUCLEAR FUEL DISPOSAL	2,029,287	1,832,904	1,546,366	1,793,384	1,498,625	1,900,150	10,600,716	1a
1b	COAL CAR INVESTMENT	227,871	226,008	224,145	222,283	220,420	218,558	1,339,285	1b
1c	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1c
1d	INCREMENTAL HEDGING COSTS	51,942	51,942	88,438	53,520	53,520	53,520	352,882	1d
2	FUEL COST OF POWER SOLD	(17,641,350)	(14,113,749)	(12,887,790)	(9,452,595)	(7,127,668)	(7,054,681)	(68,277,834)	2
2a	GAIN ON ECONOMY SALES	(3,434,011)	(3,547,385)	(1,767,209)	(912,002)	(765,451)	(811,740)	(11,237,798)	2a
3	FUEL COST OF PURCHASED POWER	29,345,542	27,880,979	27,299,381	26,809,590	29,430,031	27,532,613	168,298,137	3
3a	QUALIFYING FACILITIES	20,800,000	17,852,000	21,403,000	9,704,000	21,327,100	21,154,893	112,240,993	3a
4	ENERGY COST OF ECONOMY PURCHASES	5,549,380	2,896,743	8,382,845	11,013,710	13,743,720	7,077,431	48,663,828	4
4a	FUEL COST OF SALES TO FKEC / CKW	(5,540,213)	(5,576,844)	(5,474,473)	(5,821,752)	(6,168,880)	(6,637,259)	(35,219,419)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$438,549,965	$387,661,732	$475,511,110	$492,632,981	$621,301,501	$636,863,150	$3,052,520,438	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,394,330	7,536,675	7,664,649	7,603,911	8,491,409	9,526,718	49,217,692	6
7	COST PER KWH SOLD (¢/KWH)	5.2244	5.1437	6.2040	6.4787	7.3168	6.6850	6.2021	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	7a
7b	JURISDICTIONAL COST (¢/KWH)	5.2273	5.1466	6.2074	6.4823	7.3209	6.6888	6.2056	7b
9	TRUE-UP (¢/KWH)	0.2941	0.3276	0.3221	0.3247	0.2907	0.2593	0.3010	9
10	TOTAL	5.5214	5.4742	6.5295	6.8070	7.6116	6.9481	6.5066	10
11	REVENUE TAX FACTOR 0.00072	0.0040	0.0039	0.0047	0.0049	0.0055	0.0050	0.0047	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	5.5254	5.4781	6.5342	6.8119	7.6171	6.9531	6.5113	12
13	GPIF (¢/KWH)	0.0053	0.0060	0.0059	0.0059	0.0053	0.0047	0.0055	13
14	RECOVERY FACTOR *including* GPIF	5.5307	5.4841	6.5401	6.8178	7.6224	6.9578	6.5168	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	5.531	5.484	6.540	6.818	7.622	6.958	6.517	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2009 - DECEMBER 2009

LINE NO.		(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$683,941,154	$692,871,394	$639,279,703	$569,416,842	$417,071,062	$385,933,690	$6,214,273,493	A1
1a	NUCLEAR FUEL DISPOSAL	1,979,519	1,979,519	1,915,663	1,874,120	1,496,482	1,982,553	$21,828,572	1a
1b	COAL CAR INVESTMENT	216,695	214,833	212,970	211,108	209,245	207,383	$2,611,519	1b
1c	DOE DECONTAMINATION AND	0	0	0	0	0	0	$0	1c
	DECOMMISSIONING COSTS							$0	
1d	INCREMENTAL HEDGING COSTS	53,520	74,028	53,520	53,520	53,520	53,520	$694,510	1d
2	FUEL COST OF POWER SOLD	(6,334,043)	(14,231,863)	(4,250,289)	(5,472,641)	(6,711,083)	(10,812,349)	($116,090,101)	2
2a	GAIN ON ECONOMY SALES	(634,111)	(1,653,071)	(353,664)	(478,138)	(1,204,331)	(2,886,686)	($18,447,799)	2a
3	FUEL COST OF PURCHASED POWER	31,089,900	31,131,591	29,712,418	30,849,652	30,106,446	30,141,600	$351,329,743	3
3a	QUALIFYING FACILITIES	22,820,000	23,183,000	21,679,000	19,694,000	15,956,000	20,380,000	$235,952,993	3a
4	ENERGY COST OF ECONOMY PURCHASES	9,944,038	8,946,982	17,323,797	17,029,993	7,883,060	6,490,247	$116,281,945	4
4a	FUEL COST OF SALES TO FKEC / CKW	(7,212,596)	(7,338,510)	(7,468,260)	(7,252,161)	(6,511,495)	(5,918,406)	($76,920,848)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$735,864,076	$735,177,902	$698,104,857	$625,926,294	$458,348,906	$425,571,552	$6,731,514,025	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	10,261,393	10,257,659	10,640,511	8,965,734	8,658,115	8,125,387	106,126,486	6
7	COST PER KWH SOLD (¢/KWH)	7.1712	7.1671	6.5608	6.9813	5.2939	5.2376	6.3429	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	1.00056	7a
7b	JURISDICTIONAL COST (¢/KWH)	7.1752	7.1711	6.5645	6.9852	5.2968	5.2405	6.3465	7b
9	TRUE-UP (¢/KWH)	0.2409	0.2410	0.2323	0.2758	0.2852	0.3038	0.2793	9
10	TOTAL	7.4161	7.4121	6.7968	7.2610	5.5820	5.5443	6.6258	10
11	REVENUE TAX FACTOR 0.00072	0.0053	0.0053	0.0049	0.0052	0.0040	0.0040	0.0048	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	7.4214	7.4174	6.8017	7.2662	5.5860	5.5483	6.6306	12
13	GPIF (¢/KWH)	0.0044	0.0044	0.0042	0.0050	0.0052	0.0055	0.0051	13
14	RECOVERY FACTOR including GPIF	7.4258	7.4218	6.8059	7.2712	5.5912	5.5538	6.6357	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	7.426	7.422	6.806	7.271	5.591	5.554	6.636	15

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	CURRENT AUG 08 - DEC 08	PRELIMINARY JAN 09 - MAY 09	DIFFERENCE $	DIFFERENCE %	PRELIMINARY JUNE 09 - OCT 09	DIFFERENCE $	DIFFERENCE %	PRELIMINARY NOV 09 - DEC 09	DIFFERENCE $	DIFFERENCE %
BASE	$39.37	$39.31	($0.06)	-0.15%	$40.72	$1.41	3.59%	$42.00	$1.28	3.14%
FUEL	$60.21	$63.05	$2.84	4.72%	$63.05	$0.00	0.00%	$63.05	$0.00	0.00%
CONSERVATION	$1.45	$2.04	$0.59	40.69%	$2.04	$0.00	0.00%	$2.04	$0.00	0.00%
CAPACITY PAYMENT	$5.46	$8.55	$3.09	56.59%	$8.55	$0.00	0.00%	$8.55	$0.00	0.00%
ENVIRONMENTAL	$0.40	$0.94	$0.54	135.00%	$0.94	$0.00	0.00%	$0.94	$0.00	0.00%
STORM RESTORATION SURCHARGE	$1.11	$1.45 *	$0.34	30.63%	$1.45	$0.00	0.00%	$1.45	$0.00	0.00%
SUBTOTAL	$108.00	$115.34	$7.34	6.80%	$116.75	$1.41	1.22%	$118.03	$1.28	1.10%
GROSS RECEIPTS TAX	$2.77	$2.96	$0.19	6.86%	$2.99	$0.03	1.01%	$3.03	$0.04	1.34%
TOTAL	$110.77	$118.30	$7.53	6.80%	$119.74	$1.44	1.22%	$121.06	$1.32	1.10%

* Storm Charge effective November 1, 2008