BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 030001-EI

In the Matter of

FUEL AND PURCHASED POWER COST
RECOVERY CLAUSE WITH GENERATING
PERFORMANCE INCENTIVE FACTOR.
_______________________________________/

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VOLUME 2

Pages 200b through 397

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN LILA A. JABER
COMMISSIONER J. TERRY DEASON
COMMISSIONER BRAULIO L. BAEZ
COMMISSIONER RUDOLPH BRADLEY
COMMISSIONER CHARLES M. DAVIDSON

DATE: Wednesday, November 12, 2003

TIME: Commenced at 9:30 a.m.
Adjourned at 5:34 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: JANE FAUROT, RPR
Chief, Office of Hearing Reporter Services
FPSC Division of Commission Clerk and
Administrative Services
(850) 413-6732

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
13	KMD-1 through KMD-6	296	341
14	WTW-1	344	444
15	Hemrich Memo, 8/7/02	376	444
16	OPA Document 3/12/03	376	444
17	Buddy Maye Deposition Transcript May 13, 2003	376	444
18	William Whale Depo Transcript October 28, 2003	378	444
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P R O C E E D I N G S

(Transcript continues in sequence from Volume 1.)

(REPORTER NOTE: Continuation of prefiled testimony inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 030001-EI

SEPTEMBER 12, 2003

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 Manager of Regulated Wholesale Power Trading 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, petroleum coke, and natural gas, (2) the availability of natural gas to FPL, (3) generating unit heat rates and availabilities, (4) the quantities and costs of wholesale (off-system) power and purchased power transactions, (5) new projects for which FPL is seeking recovery through the Fuel Clause in 2004, (6) FPL's hedging activities in 2003, and (7) FPL's Risk Management Plan for fuel procurement in 2004. The projected values for (1) through (4) were used as input data to the POWRSYM model that FPL uses to calculate the fuel costs to be included in the proposed fuel cost recovery factors for the period of January through December 2004.

Q. **How is your testimony organized?**

A. My testimony first describes the basis for the fuel price forecast for oil, coal and petroleum coke, and natural gas, as well as, the projection for natural gas availability. A description of FPL's forecast methodology change for 2004 is also included in this part of the testimony. The second part of the testimony addresses plant heat rates, outage factors, planned outages, and changes in generation capacity. This is followed by a description of projected wholesale (off-system) power and purchased power transactions. Next, the testimony describes a new project for which FPL is seeking recovery through the Fuel Clause in 2004: the acquisition of additional railcars for Scherer Unit No. 4. The testimony concludes with a presentation of FPL's 2004 Risk Management Plan for fuel procurement, as outlined in Order PSC- 02-1484-FOF-EI issued on

October 30, 2002. Included in this section is an overview of FPL's fuel hedging objectives and an itemization of projected, prudently-incurred incremental operating and maintenance expenses for maintaining FPL's expanded, non-speculative financial and physical hedging program for the projected period. Lastly, the testimony provides a discussion of FPL's hedging activities and fuel cost mitigation strategies for 2003.

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

A. Yes, I have. It consists of the entire Appendix I and Schedules E2, E3, E4, E5, E6, E7, E8 and E9 of Appendix II of this filing.

FUEL PRICE FORECAST

Q. Has FPL's forecast methodology changed for the 2004-recovery period?

A. Yes, in part. For natural gas commodity prices, the forecast methodology has changed to a weighted average of the NYMEX Natural Gas Futures contract (forward curve) and the most likely forecasts from The PIRA Energy Group, Global Insights (formerly DRI-WEFA) and Cambridge Energy Research Associates, Inc. (CERA). The forecasts for heavy and light fuel oil commodity prices and transportation costs, natural gas transportation costs, natural gas availability and delivered coal and petroleum coke prices continue to be developed by FPL. FPL implemented this change for its natural gas price forecast primarily because of the volatility of this commodity. Utilizing the forward curve for natural gas and the expertise of these three energy industry consultants incorporates a range of interpretations of natural gas data into the forecast.

The forward curve for natural gas is a representation of expected future prices at any given point in time. The basic assumption made with respect to the forward curve for natural gas is that all available natural gas data that could impact the price of natural gas in the future is incorporated into the curve at all times. The forward curve that FPL incorporated into the natural gas forecast is from the close of business on the latest possible date in August 2003 that still allowed FPL the necessary time to complete its filing requirements. The three consulting firms that FPL utilized for natural gas price projections are well equipped and have ample resources available to obtain and analyze the data necessary to develop a price forecast for natural gas. These three consulting firms are among the leaders in the energy industry. For example, The PIRA Energy Group is retained by more than 350 companies located in 34 countries. FPL's reason for calculating projections based on a weighted average of price forecasts was to incorporate as much interpretation of gas data as possible into its forecast, while moderating the impact of one individual forecast (primarily one of the three consultants) that could be markedly different than that of the others due to a strong difference of opinion with regard to the relevant data. FPL is also considering the use of these three consultants for its fuel oil price forecasts in the future. At this time, FPL is evaluating the performance of these three consultants with respect to the fuel oil markets, particularly the residual fuel oil market. FPL will continue to constantly monitor the fundamentals of the fuel oil and natural gas markets in order to respond to rapidly changing market conditions and adjust its hedging strategies accordingly, in a timely manner.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2004 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 production, (3) the extent to which OPEC production matches actual demand for OPEC crude oil, (4) the price relationship between heavy fuel oil and crude oil, (5) the price relationship between heavy oil and natural gas and (6) the terms of FPL's heavy fuel oil supply and transportation contracts.

World demand for crude oil and petroleum products is projected to increase moderately in 2004 from projected 2003 levels, primarily due to increases in demand in the U.S. and Pacific Rim countries. Although crude oil production and worldwide refining capacity will be more than adequate to meet the projected increase in crude oil and petroleum product demand, general adherence by OPEC members to its most recent production accord should prevent significant overproduction of crude oil. When coupled with the continuation of historically low domestic crude oil and petroleum product inventory levels, the supply of crude oil and petroleum products will remain somewhat tight during most of 2004.

Q. What is the projected relationship between heavy fuel oil and crude oil prices during the January through December 2004 period?

A. The price of heavy fuel oil on the U. S. Gulf Coast (1.0% sulfur) is projected to be approximately 92% of the price of West Texas Intermediate (WTI) crude oil during this period.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2004 period.

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by sulfur grade and 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 that could affect the price of light fuel oil are similar to those described above for heavy fuel oil.

Q. **Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2004 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 for St. Johns' River Power Park (SJRPP) and Scherer Plant?**

A. FPL's projected dispatch cost for SJRPP is based on FPL's price projection for spot coal and petroleum coke delivered to SJRPP. The dispatch cost for Scherer is based on FPL's price projection for spot coal delivered to Scherer Plant.

For SJRPP, annual coal volumes delivered under long-term contracts are fixed on October 1st of the previous year. For Scherer Plant, the annual volume of coal delivered under long-term contracts is set by the terms of the contracts. Therefore, the price of coal delivered under long-term contracts does not affect the daily dispatch decision.

In the case of SJRPP, FPL will continue to blend petroleum coke with coal in order to reduce fuel costs. It is anticipated that petroleum coke will represent 17% of the fuel blend at SJRPP during 2004. The lower price of petroleum coke is reflected in the projected dispatch cost for SJRPP, which is based on this projected fuel blend.

Q. **Please provide FPL's projection for the dispatch cost of SJRPP and Scherer Plant for the January through December 2004 period.**

A. FPL's projection for the system average dispatch cost of "solid fuel" 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 2004 period?**

A. In general, the key 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 dominant factors influencing the projected price of natural gas in 2004 are: (1) projected natural gas demand in North America will continue to grow moderately in 2004, primarily in the electric generation sector; and (2) domestic natural gas production in 2004 is projected to be slightly below average 2003 levels. The balance of the supply to meet demand will come from increased Canadian and LNG imports.

Q. What are the factors that affect the availability of natural gas to FPL during the January through December 2004 period?

A. The key factors are (1) the existing capacity of the Florida Gas Transmission (FGT) pipeline system into Florida, (2) the existing capacity of the Gulfstream natural gas pipeline system into Florida, (3) the limited number of receipt points into the Gulfstream natural gas pipeline system, (4) the portion of FGT capacity that is contractually allocated 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. FPL currently has firm natural gas transportation capacity on FGT ranging from 750,000 to 874,000 million BTU per day, depending on the month. Total demand for natural gas in the state during the January through December 2004 period (including FPL's firm allocation) is projected to be between 700,000 and 850,000 million BTU per day below the total pipeline capacity into the state. FPL projects that it could acquire, if economic, an additional 510,000 to 650,000 million BTU per day of natural gas transportation beyond FPL's 750,000 to 874,000 million BTU per day of firm allocation. This projection is based on the current capability of the two interconnections between Gulfstream and FGT pipeline systems and 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 2004 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.

ALTERNATIVE PRICE FORECASTS FOR FUEL OIL AND

NATURAL GAS SUPPLY

Q. Has FPL prepared alternative fuel price forecasts?

A. No. FPL has not prepared alternative fuel price forecasts. For the 2004 Fuel Cost Recovery Filing, FPL did not believe that it was necessary to produce alternative fuel price forecasts. The primary reasons for this change are the implementation of FPL's expanded hedging program and its methodology change for the natural gas price forecast.

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

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

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

Q. Are you providing the outage factors projected for the period

January through December 2004?

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 January through December 2004 period.

Q. Please describe the significant planned outages for the January through December 2004 period.

A. Turkey Point Unit No. 3 is scheduled to be out of service for refueling and replacement of the reactor vessel head from September 25, 2004, until November 29, 2004 or 65 days during the projected period. St. Lucie Unit No. 2 will be out of service for refueling from November 22, 2004 until December 22, 2004 or 30 days during the projected period. St. Lucie Unit No. 1 will be out of service for refueling from March 22, 2004 until April 16, 2004 or 25 days during the projected period. Scherer Unit No. 4 will be out of service for a steam turbine and boiler overhaul from February 28, 2004 until April 11, 2004 or 44 days during the projected period. St.

Johns River Unit No. 2 will be out of service for a steam turbine overhaul and scrubber maintenance from February 28, 2004 until April 25, 2004 or 58 days during the projected period. Lauderdale Unit No. 4 will be out of service for a steam turbine/generator and CT A/B major overhaul from February 20, 2004 until April 15, 2004 or 56 days. Manatee Unit No. 2 will be out of service for a generator and boiler overhaul from February 14, 2004 until April 28, 2004 or 75 days during the projected period.

Q. Please list any changes to FPL's generation capacity projected to take place during the January through December 2004 period.

A. There is no significant change to FPL's generation capacity projected to take place during the January through December 2004 period.

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power and purchased power transactions forecasted for January through December 2004?

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 as all savings and gains 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. 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. 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 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. Additionally, FPL has a 50 MW purchase of firm capacity and energy from Florida Power Corporation for 2004. FPL has also purchased exclusive dispatch rights for the output of 6 combustion turbines totaling approximately 950 MW (the output varies depending on the season). The agreements for the combustion turbines are with Progress Energy Ventures, Reliant Energy Services, and Oleander Power Project L.P. FPL provides natural gas for the operation of each of these three facilities as well as light fuel oil for two of the facilities. 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 2004 period.**

A. Under the UPS agreement, FPL's capacity entitlement during the projected period is 931 MW from January through December 2004.

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. For the period, FPL projects the purchase of 7,641,267 MWh of UPS Energy at a cost of $143,352,000. The total UPS Energy projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of the St. Johns River Power Park generation are projected to be 2,800,455 MWh for the period at an energy cost of $41,053,000. 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 494,279 MWh at a cost of $1,471,163. These projections are shown on Schedule E7 of Appendix II.

Energy purchases from Florida Power Corporation, under the 50 MW purchase agreement, are projected to be 439,150 MWh at a cost of $8,730,202. These projections are shown on Schedule E7 of Appendix II.

FPL projects to dispatch 1,497,254 MWh from its combustion turbine agreements at a cost of $94,180,393. 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 7,115,665 MWh at a cost to FPL of $148,266,648.

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

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 mechanism prescribed in the contract is used to project monthly energy costs.

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 and expected market conditions.

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

A. FPL has projected 1,301,000 MWh of wholesale (off-system) power sales for the period of January through December 2004. The projected fuel cost related to these sales is $52,502,900. The projected transaction revenue from these sales is $63,863,750. The projected gain for these sales is $7,048,624 and is credited to our customers.

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 cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

A. FPL projects the sale of 502,068 MWh of energy at a cost of $1,435,065. These projections are shown on Schedule E6 of Appendix II.

Q. What are the forecasted amounts and costs of wholesale (off-

system) power purchases for the January to December 2004 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 1,477,135 MWh at a cost of $52,338,486. If generated, FPL estimates that this energy would cost $59,905,035. Therefore, these purchases are projected to result in savings of $7,566,549.

ACQUISITION OF ADDITIONAL RAILCARS FOR SCHERER UNIT NO. 4 IN 2004

Q. Is FPL seeking recovery of any new projects through the Fuel Cost Recovery Clause in 2004?

A. Yes. FPL is seeking recovery of the cost of additional railcars that will be used to haul coal from Wyoming's Powder River Basin (PRB) to Plant Scherer.

Q. Why does FPL need additional railcars to haul PRB coal to Plant Scherer?

A. FPL has been relying on the surplus capacity of railcars in the existing Plant Scherer railcar pool. The upcoming conversion of Scherer Unit No. 1 and Unit No. 2 to PRB coal by the owners of those units will erase the railcar pool surplus and, in turn, will require three of the Plant Scherer co-owners, including FPL, to contribute additional railcar resources to the pool.

Q. When are the additional FPL railcars needed at Plant Scherer?

A. The additional railcars are needed at Plant Scherer by the end of the first quarter of 2004.

Q. How many additional railcars are required by FPL?

A. FPL needs to acquire 137 additional railcars.

Q. What is the cost of the 137 additional railcars?

A. The current cost estimate for the additional railcars is approximately $7.7 million.

Q. Please explain how FPL determined that it needed 137 additional railcars.

A. The decision to convert Scherer Unit No. 1 and Unit No. 2 to PRB coal caused the operating agent for Plant Scherer, Georgia Power Company/Southern Company Services, to prepare a transportation analysis. The plan that resulted was submitted to the Scherer co-owners at the July 23, 2002 meeting of the Fuels Committee for consideration. The plan was finalized on August 29, 2002, based on key logistic parameters including estimated unit train cycle times and current coal burn projections. The process indicated a need for 937 additional railcars in the pool, 137 of which would service the needs of FPL.

Q. How was the cost of the new railcars determined?

A. The cost of the new railcars was based on competitive bids.

Q. Will FPL lease or buy the 137 railcars?

A. For purposes of this filing, FPL projected the purchase of 137 additional railcars, however a lease/buy analysis will be completed approximately 45 days before construction of the railcars to determine the least-cost alternative. If the lease/buy analysis shows that leasing is the least-cost alternative, FPL will reflect any differences through the normal true-up mechanisms.

2004 RISK MANAGEMENT PLAN

Q. Has FPL completed its risk management plan as outlined in Order PSC- 02-1484-FOF-EI issued on October 30, 2002?

A. Yes. FPL's 2004 Risk Management Plan is provided on pages 5 and 6 of Appendix I.

Q. Please describe FPL's hedging objectives.

A. FPL's fuel hedging objectives are to effectively execute a well-disciplined and independently controlled fuel procurement strategy to manage fuel price stability (volatility minimization), to potentially achieve fuel cost minimization and to achieve asset optimization. FPL's fuel procurement strategy aims to mitigate fuel price increases and reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL's customers.

Q. Does FPL's hedging plan for 2004 include strategies to mitigate the replacement fuel costs associated with the extended outage of Turkey Point Unit No. 3 due to the reactor vessel head replacement?

A. Yes. FPL's fuel hedging strategies incorporate all of FPL's planned unit outages for a given time period. FPL takes mitigation steps to lower the impact of all plant outages, through the procurement of fuel and purchased power.

Q. Does FPL project to incur incremental operating and maintenance expenses with respect to maintaining an expanded, non-speculative financial and/or physical hedging program for which it is seeking recovery in the January through December 2004 period?

A. Yes. FPL projects to incur incremental expenses of $400,257 for its Trading and Operations group and $27,600 for its Systems Group.

The expenses projected for the Trading and Operations Group are composed of the salaries of two additional personnel that were added in 2003 to support the enhanced hedging program and one "open" position that FPL projects it will fill in 2004. This position will also support the enhanced hedging program. The expense projected for the Systems Group is for incremental annual license fees for FPL's volume forecasting software. Volume forecasting is done on a continuous basis to help FPL manage its hedge positions by adjusting those positions according to updated fuel volume forecasts on an ongoing basis. The incremental expense for an annual license fee was necessary to fully support FPL's expanded hedging program.

Q. Are these projected hedging expenses prudent?

A. Yes, for the reasons just described.

2003 HEDGING SUMMARY

Q. Were FPL's actions through July 31, 2003, to mitigate fuel and purchased power price volatility through implementation of its non-speculative financial and/or physical hedging programs prudent?

A. Yes. FPL's hedging strategies throughout 2003 were consistent with its market view throughout the period. In late 2002 and early

2003, FPL's focus was on the fuel oil markets and protecting its customers from the high level of uncertainty in the Middle East, as well as the Venezuelan oil workers strike. FPL considered the possible impact a war in the Middle East could have on fuel oil prices and took the appropriate action. Therefore, consistent with that view, FPL hedged a greater percentage of residual fuel oil for the first quarter of 2003. This included fixed price transactions, as well as, building fuel oil inventories at the end of 2002. Given the record high storage levels of natural gas and a longer-term view that the market would be stable throughout the year, FPL's hedges across all commodities were representative of FPL's market view.

The fundamentals that existed in the gas market at the time FPL's hedges were put in place did not predict the significant change that took place in the first quarter of 2003. The severe spike in natural gas prices and cooling degree-days that coincided in the month of March were unanticipated by the market and were deemed as short-term occurrences. Given this information, FPL would not have hedged additional natural gas volumes during the price spike. Subsequent to the spike in natural gas prices, it became clear that the original fundamentals FPL used to execute its hedges had changed dramatically. Record low levels of storage at the end of the withdrawal season, below expected production levels and extended cold weather completely changed the natural gas market. With these fundamental changes, FPL began increasing its hedging activity for the balance of 2003 and for 2004. FPL has taken advantage of market opportunities at specific times to help protect its customers from the volatility that exists in the natural gas and fuel oil markets. Consistent with FPL's presentation that was given to the parties on June 30, 2003, FPL is moving forward with its expanded hedging program. FPL will continue to hedge around its market view and continues to make changes to its hedging plan as its market view is updated.

In addition to the long-term hedges described above, FPL continuously worked to lower fuel costs on a day-to-day basis. From re-dispatching its system around gas-fired generation during the natural gas spike, to constantly seeking and executing on market opportunities for wholesale power; FPL has made every effort to mitigate the impact of highly volatile fuel prices. Through July 31, 2003, FPL has been able to achieve gains on its wholesale power sales of approximately $10.4 million and savings from its wholesale power purchases of approximately $16.2 million. These gains and savings are directly passed through to FPL's customers and help to lower overall fuel costs.

FPL constantly monitors the fundamentals of the energy markets and as conditions change, FPL will make further adjustments to its hedging program to meet FPL's objective of reduced volatility to its customers. FPL will continue to utilize the additional resources (both systems and personnel) it acquired as a result of Order PSC-02-1484-FOF-EI issued on October 30, 2002, to meet its goals and the goals of its customers.

Q. Does this conclude your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Terry A. Davis
Docket No. 030001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: April 1, 2003

Q. Please state your name, business address and occupation.

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated in activities related to the cost recovery clauses, the rate case, budgeting, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes, I have.

Counsel: We ask that Ms. Davis' Exhibit consisting of four schedules be marked as Exhibit No. _____ (TAD-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) true-up calculations for the period of January 2002 through December 2002 and the Purchased Power Capacity Cost true-up calculations for the period of January 2002 through December 2002 set forth in your exhibit?

A. Yes. These documents were prepared under my direction.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Q. What is the amount to be refunded or collected through the fuel cost recovery factor in the period January 2004 through December 2004?

A. A net amount to be refunded of $1,056,921 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $1,056,921 was calculated by taking the difference in the estimated January 2002 through December 2002 under-recovery of $16,703,076 and the actual under-recovery of $15,646,155, which is the sum of the Period-to-Date amounts on lines 7, 8, and 12 shown on Schedule A-2, page 2, of the monthly filing for December 2002. The estimated true-up amount for this period was approved in Order No. PSC-02-1761-FOF-EI dated December 13, 2002. Additional details supporting the approved estimated true-up amount are included on Schedule E1-A filed August 20, 2002.

Q. Ms. Davis has the estimated benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for 2003?
A. Yes, it has.

Q. What is the actual threshold for 2003?
A. Based on actual data for 2000, 2001, and now 2002, the threshold is calculated to be $1,405,575.

Q. What incremental hedging support costs related to administering Gulf's recently approved hedging program is Gulf seeking to recover for 2002?
A. Gulf is not seeking to recover any incremental hedging support costs related to administering its recently approved hedging program for the 2002 recovery period.

Q. Is Gulf seeking to recover any gains or losses from hedging settlements in the 2002 recovery period?
A. Yes. On the December 2002 Fuel Schedule A-1, Period to Date, Gulf has recorded a net gain of $238,750 related to hedging activities in 2002. Mr. Ball will address the details of those hedging activities in his testimony.

Q. Ms. Davis, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedules CCA-1, CCA-2, and CCA-3 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation for the period January 2002 through December 2002.

Q. What is the amount to be refunded or collected in the period January 2004 through December 2004?

A. An amount to be refunded of $193,696 was calculated as shown in Schedule CCA-1, of my exhibit.

Q. How was this amount calculated?

A. The $193,696 was calculated by taking the difference in the estimated January 2002 through December 2002 over-recovery of $353,333 and the actual over-recovery of $547,029, which is the sum of lines 12 and 13 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in Order No. PSC-02-1761-FOF-EI dated December 13, 2002. Additional details supporting the approved estimated true-up amount are included on Schedule CCE-1A filed August 20, 2002.

Q. Please describe Schedules CCA-2 and CCA-3 of your exhibit.

A. Schedule CCA-2 shows the calculation of the actual over-recovery of purchased power capacity costs for the period January 2002 through December 2002. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the over-recovery for the period January 2002 through December 2002. This is the same method of calculating interest that is used in the Fuel and Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

Q. Ms. Davis, does this complete your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Terry A. Davis
Docket No. 030001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: August 12, 2003

Q. Please state your name, business address and occupation.

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys, in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts

Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated in activities related to the cost recovery clauses, budgeting, a retail rate case, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and/or coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Ms. Davis' Exhibit consisting of five schedules be marked as Exhibit No. _____ (TAD-2).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2003 through December 2003 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2003 through December 2003 set forth in your exhibit?

A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Q. How were the estimated true-ups for the current period calculated for both fuel and purchased power capacity?

A. In each case the estimated true-up calculations include seven months of actual data and five months of estimated data.

Q. Ms. Davis, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2004 through December 2004?

A. The fuel cost recovery true-up for this period is an increase of .1877¢/kwh. As shown on Schedule E-1A, this includes an estimated under-recovery for the January through December 2003 period of $20,963,299, plus a final over-recovery for the January through December 2002 period of $1,056,921 (see Schedule 1 of Exhibit TAD-1 in this docket filed on April 1, 2003). The resulting net under-recovery is $19,906,378.

Q. Ms. Davis, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?
A. Schedules CCE-1a and CCE-1b of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2004 through December 2004 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2004 through December 2004?
A. The true-up for this period is a decrease of .0118¢ as shown on Schedule CCE-1a. This includes an estimated over-recovery of $1,058,876 for January 2003 through December 2003. It also includes a final true-up over-recovery of $193,696 for the period of January 2002 through December 2002 (see Schedule CCA-1 filed April 1, 2003). The resulting over-recovery is $1,252,572.

Q. Ms. Davis, does this complete your testimony?
A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Terry A. Davis
Docket No. 030001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: September 12, 2003

Q. Please state your name, business address and occupation.

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for seven years with a seismic survey firm, Geophysical Field Surveys, in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in

Accounts Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated in activities related to the cost recovery clauses, the rate case, budgeting, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and/or coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

Q. Have you previously filed testimony before this Commission in this on-going docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 2004 through December 2004. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2004 through December 2004.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of January 2004 through December 2004?

A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Counsel: We ask that Ms. Davis's Exhibit consisting of fourteen schedules, be marked as Exhibit No. _____(TAD-3).

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2002 through December 2002?

A. The GPIF result is shown on Line 33 of Schedule E-1 as an increase of .0041¢/kwh, thereby rewarding Gulf $431,920.

Q. Has there been any change that would affect the estimated true-up for 2003 filed by Gulf on August 12, 2003?

A. Yes. The actual fuel over/under recovery calculation for August 2003 resulted in an under-recovery of

$3,806,123.03 as shown on revised Schedule E-1b, page 2, of my exhibit. This amount is $2,945,593.11 more than projected on the original version of this schedule filed on August 12, 2003. I have revised this schedule and included the new estimated true-up amount on Schedule E-1b and in the resulting calculations on the other schedules in the E-1 series.

Q. What is the appropriate revenue tax factor to be applied in calculating the levelized fuel factor?

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs as shown on Line 31 of Schedule E-1.

Q. Ms. Davis, what is the levelized projected fuel factor for the period January 2003 through December 2003?

A. Gulf has proposed a levelized fuel factor of 2.459¢/kwh. It includes projected fuel and purchased power energy expenses for January 2004 through December 2004 and projected kwh sales for the same period, as well as the true-up and GPIF amount. The levelized fuel factor has not been adjusted for line losses.

Q. How does the levelized fuel factor for the projection period compare with the levelized fuel factor for the current period?

A. The projected levelized fuel factor for 2004 is .111 cents/kwh more or 4.7 percent higher than the levelized fuel factor for 2003 upon which current fuel factors are based.

Q. Ms. Davis, how were the line loss multipliers used on Schedule E-1E calculated?

A. They were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest mwh Load Flow Allocators.

Q. Ms. Davis, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, OSIII, and OSIV?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 2.472¢/kwh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. Ms. Davis, how were the time-of-use fuel factors calculated?

A. These were calculated based on projected loads and system lambdas for the period January 2004 through December 2004. These factors included the GPIF and true-up, and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2003 and how would the change affect the cost of 1000 kwh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2003 is 2.359¢/kwh compared with the proposed factor of 2.472¢/kwh. For a residential customer who uses 1000 kwh in January 2004, the fuel portion of the bill would increase from $23.59 to $24.72.

Q. Has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my Exhibit TAD-3. These costs represent the estimated averages for the period from January 2004 through December 2005.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2004 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-AAA-EI, a benchmark level of $2,016,185 has been calculated for 2004. The actual gains for 2001, 2002, and the estimated gains for 2003 on all non-separated sales have been averaged to determine the minimum projected threshold for 2004 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2003. The estimated gains on all non-separated sales are projected to be $383,000, whereas the threshold is estimated at $2,016,185.

Q. You stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1a and CCE-1b, and Schedule CCE-2 of my exhibit relate to the calculation of the PPCC recovery factors for the period January 2004 through December 2004.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Bell has provided me with Gulf's projected purchased power capacity transactions. Gulf's total projected net capacity expense which includes a credit for transmission revenue for the period January 2004 through December 2004 is $19,542,907. The jurisdictional amount is $18,859,271. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

Q. What methodology was used to allocate the capacity payments to rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology used in Gulf's last full requirements rate case and approved by the Commission in Order No. PSC-02-0787-FOF-EI issued

June 10, 2002, in Docket No. 010949-EI. For purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs to rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study used in Gulf's last rate case.

Q. How were the allocation factors calculated for use in the PPCC Recovery Clause?

A. The allocation factors used in the PPCC Recovery Clause have been calculated using the 2001 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on Page 1 of Schedule CCE-2.

Q. Please describe the calculation of the cents/kwh factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, the 12/13th of the jurisdictional capacity cost to be recovered is allocated to rate class based on the demand allocator, with the remaining 1/13th allocated based on energy. The total revenue requirement assigned to each rate class shown in column E is then divided by that class's projected kwh sales for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each customer's total kwh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1000 kwh?
A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1000 kwh will be $1.94.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?
A. The fuel and capacity factors will be effective beginning with the first Bill Group for January 2004 and continuing through the last Bill Group for December 2004.

Q. Ms. Davis, does this complete your testimony?
A. Yes, it does.

CHAIRMAN JABER: And, Staff, I think we can then just get to the issues that have proposed stipulations so that parties are comfortable leaving the rest of the proceeding if they want to leave.

MS. KAUFMAN: Chairman, I don't want to interrupt, but before you do that, there is an error, I think, in the prehearing order on Issue 30 that reflects FIPUG's position as no position. And I had discussed that with Mr. Keating previously, so I don't believe that Issue 30 is going to be stipulated. And this may relate to Ms. Welch, as well.

CHAIRMAN JABER: Do we have your revised position, Ms. Kaufman, or can you get it to us?

MS. KAUFMAN: I can tell you what it is.

CHAIRMAN JABER: Go ahead.

MS. KAUFMAN: And our position would be the Commission should ensure that any costs included in base rates are not included in the clause for recovery.

CHAIRMAN JABER: Read it one more time.

MS. KAUFMAN: The Commission should ensure that any costs included in base rates are not included in the clause for recovery.

CHAIRMAN JABER: Okay. Let the record reflect FIPUG's position on Issue 30 has been revised. Staff, take us issue-by-issue, what you believe has a proposed stipulation, we will rule on it.

MR. KEATING: We discussed earlier perhaps going through and handling just the companies, all of whose issues were stipulated. Do you want to go just through all of those companies or through all the companies' stipulated issues?

CHAIRMAN JABER: I want to do it the most efficient way possible. So let's just -- what might that be?

MR. KEATING: I think it might be easier for us to go through just Gulf and FPC right now since all their issues are stipulated. I don't know that staff is going to be able to -- it may be more difficult for us to go through the other companies' issues at this point in time, because there are some fallouts that may be stipulated as a result, and we just haven't had the time to give it that thought.

CHAIRMAN JABER: Let's start with Gulf.

MR. KEATING: For Gulf Power, Issue 11 would agree with -- we would agree with Gulf Power's position as stated on Issue 1 in the prehearing order.

CHAIRMAN JABER: So what you need from the Commission is a motion to accept the proposed stipulation between -- is it all the parties and Gulf, or is it staff and Gulf?

MR. KEATING: The other parties have simply, as I understand, taken no position on that issue.

CHAIRMAN JABER: Okay. Commissioners, can I have a motion to accept Gulf's proposed stipulation on Issue 1?

COMMISSIONER DEASON: Let me ask a question. Do we need to go issue-by-issue on all of these or can you just review all of the Gulf stipulations and we can do them at one time.

MR. KEATING: I can do that just as well. We can go through and give you all the issue numbers. For Gulf Power that would be Issues 1 through 11, Issue 12, Issues 16A and 16B, and Issues 24 through 29.

MR. BADDERS: And on Issue 29 there is an error in the table. It shows a dollar per kWh, it should be cents.

MR. KEATING: And with that clarification, I believe staff can recommend approval of Gulf Power's position, or what is shown as the stipulated position in the prehearing order on those issues.

CHAIRMAN JABER: Mr. Badders, you said the error is in Issue 29, Page 40 of the prehearing order, and what is the change?

MR. BADDERS: There is a dollar sign. If you look over under capacity cost-recovery factors, it is dollars per kWh. It should be cents.

CHAIRMAN JABER: Okay. Commissioners, again, it looks like a stipulation has been reached with Gulf as it relates to Issues 1 through 12, 16A, 16B, 24 through 29, recognizing the change to Issue 29.

COMMISSIONER DEASON: Move approval as revised for 29, and 1 through 12, 16A, 16B, and 24 through 28; 29 as revised.

CHAIRMAN JABER: And a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Those issues as it relates to Gulf have been approved unanimously.

And, Mr. Badders, was there anything else we needed to address as it relates to your company?

MR. BADDERS: No, that just leaves us with Issue 30. We do not have testimony on that, but I may reserve the right to cross-examine witnesses.

CHAIRMAN JABER: Oh. So you are not excusable. You have to be here, okay.

Mr. Keating, you said Gulf was the first company. What was the second one?

MR. KEATING: The second was Florida Public Utilities Company.

CHAIRMAN JABER: Okay.

MR. KEATING: And on Issues -- for Issues 1 through 9, and Issue 15A, staff can recommend approval of the position shown for Florida Public Utilities Company, both the Fernandina Beach and Marianna divisions.

CHAIRMAN JABER: Are there any changes to any of the positions, Florida Public Utilities Company? Any changes, Mr. Horton?

MR. HORTON: No, ma'am. No.

CHAIRMAN JABER: Commissioners?

COMMISSIONER DEASON: Madam Chairman, I can move approval of the stipulations for FPUC, Marianna, and Fernandina on Issues 1 through 9 and 15A.

COMMISSIONER BRADLEY: Second.

CHAIRMAN JABER: And a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: The proposed stipulations related to 1 through 9 and 15A for FPUC have been approved unanimously. What else, Mr. Keating?

MR. KEATING: Those are the only two companies whose issues are entirely stipulated at this point in time.

CHAIRMAN JABER: Okay.

MR. HORTON: And, Madam Chairman, with that, may I be excused?

CHAIRMAN JABER: Absolutely.

MR. HORTON: Thank you.

CHAIRMAN JABER: Thank you.

Mr. Keating, does that take us to a point where we can put the first witness on the stand?

MR. McGEE: Madam Chairman.

CHAIRMAN JABER: Yes.

MR. McGEE: I have a correction that I need to make to Progress Energy issues, one of which I hope will result in a stipulation. The first one is Issue 30 on Page 43. In the second of line that position, as that stated there, the words that refer to the last sentence of staff's position, staff's position has been reworded since the time that position was written. So if I may, I would like to strike three words, "last sentence which," and insert in its place, "position of Staff Witness Brinkley who," so that the beginning of the issue would read, "Progress Energy agrees with staff's position, except for the position of Staff Witness Brinkley, who proposes an adjustment."

CHAIRMAN JABER: And you believe that results in a stipulation, Mr. McGee?

MR. McGEE: That would be the next issue. On Issue 31A on Page 45, I would like to change Progress Energy's position to agree with staff. And I believe that does result in a stipulation.

CHAIRMAN JABER: Okay. Let's take it issue-by-issue. With regard to Issue 30, let the record reflect the change in Progress Energy's position as articulated by Mr. McGee. For Issue 31A, let the record reflect that Progress's position is now agree with staff. And, Mr. Keating, do you all have a stipulation with that change?

MR. KEATING: From staff's perspective, we definitely agree with the company on Issue 31A.

CHAIRMAN JABER: And I see that the parties had taken no position on this issue, is that right?

MR. KEATING: That is my understanding. And Ms. Kaufman and Mr. Vandiver may have something to add.

MS. KAUFMAN: Right. We had changed our position on Issue 30, that is what I had just referenced earlier, that there was an error.

CHAIRMAN JABER: Right. But what about Issue 31A?

MS. KAUFMAN: We have had this discussion before. I'm not clear how Issue 31A can be stipulated with Issue 30 still in contention.

CHAIRMAN JABER: Okay.

MS. KAUFMAN: And I'm open to understanding that, absolutely.

CHAIRMAN JABER: Okay. We will leave it an open question. I'm sure we will be taking a break in the very near future, you all can talk about it a little bit more. Anything else?

MR. KEATING: Other preliminary matters?

CHAIRMAN JABER: Uh-huh.

MR. KEATING: There are a couple of other things on my list. One was just to point out that Public Counsel's witnesses, as I understand, would not be present until tomorrow, and I don't think that is going to be a problem. I think we probably won't get to those witnesses until tomorrow.

If we do get to a point today where we are ready for them, I think we could, if necessary, take some staff witnesses out of order and come back to Public Counsel's witnesses, because I don't think we will get through everything today regardless.

CHAIRMAN JABER: Okay. Let's cross that bridge when we come to it. But the question, I think, that is on the table is will anyone have any objection to taking staff witnesses up today if we get to that point?

Go ahead, Mr. Keating, what's next on your list? It looks like no one has any objection to taking staff witnesses out of order.

MR. KEATING: The next things on my list is Tampa Electric filed a notice of intent to request official recognition of two Commission orders and one Florida Supreme Court order. I think our recent practice has been that we felt there was no need to officially recognize those orders. I don't see that there is any harm in doing so, but that is one of the preliminary matters that I felt I needed to bring up.

MR. BEASLEY: Madam Chairman, we have the two Commission decisions and the Supreme Court opinion. They were officially noticed by the Commission in your proceeding two years ago when an issue was raised by the Florida Industrial Power Users Group concerning transactions with Hardee Power Partners. The same issues have arisen in this proceeding. We have these and can distribute them to you. The first order is your order on need determination back in 1989, where the Commission determined that the transactions in question would bring approximately $90 million worth of benefits to Tampa Electric's customers.

The second order is the one entered after the fuel adjustment hearing two years ago where the Commission heard similar arguments from FIPUG, their challenge to the reasonableness of the power purchase agreement between Tampa Electric and Hardee Power Partners. You rejected that argument unanimously.

The third order is the opinion of the Supreme Court of Florida affirming your decision two years ago. This order was issued last November. I would be happy to distribute these to you if you would find them useful and convenient to have.

CHAIRMAN JABER: Mr. Keating, it's my understanding as it relates to the orders -- I have received a copy of your request for official recognition through staff, as well. And it is my understanding, Mr. Keating, that as it relates to Commission orders, there is no need to officially recognize the agency decisions. You all are free to cite to whatever Commission orders you want in your briefs. So I won't take any action with regard to those orders.

Now, tell me what to do as it relates to the request for the Supreme Court case?

MR. KEATING: As it relates to that particular request, and staff has no objection to the Commission officially recognizing that. And, I guess, my thinking had always been that we could consider that and parties could rely on those types of orders, as well. It is an appeal of one of our own orders.

CHAIRMAN JABER: Parties, I tend to agree. It is my understanding that any district court of appeal case on point, Supreme Court case as long as you all have notice and an opportunity to respond in briefs, that there is no need to take action as it relates to the Florida case.

MR. McWHIRTER: FIPUG has no objection to the Commission taking administrative notice of these orders and the Supreme Court decision. We do object to Mr. Beasley's characterization of the current issue being the same as the issues in those cases, and if he will withdraw that comment, we won't fuss about it.

CHAIRMAN JABER: Well, you know, Mr. McWhirter, I think that your objection is noted. I think you have an opportunity to address it in your briefs. And I don't intend to take any other action as it relates to this request.

MR. BEASLEY: Madam Chairman, the reason I did this was out of convenience, because this is usually a bench-decision type proceeding, and I just wanted to have these available for you to refer to in the event you wanted to. And I can distribute them, or just put them back here on the --

CHAIRMAN JABER: Mr. McWhirter, do you have a copy of the case? Do you need a copy?

MR. McWHIRTER: No I don't, Madam Chairman.

CHAIRMAN JABER: Okay. Pass out the copies, Mr. Beasley, when we take a break. But something you said with regard to the bench decision, we always decide that issue on an issue-by-issue basis. So to the degree there is an issue as it relates to your application or argument of the case, I will entertain objections at that point.

MR. BEASLEY: That's fine.

CHAIRMAN JABER: Mr. Keating, what else?

MR. KEATING: That is all that I have on my list for preliminary matters. I do, at some point, and perhaps I could suggest it after the break, hope to get back to potentially excusing Staff Witness Kathy Welch, and we will have to talk to the parties about that.

CHAIRMAN JABER: I would like to take up all the preliminary matters at this point, take a break, and get the first witness up on the stand. So, parties, do you have preliminary matters you want to bring to our attention?

Mr. Beasley.

MR. BEASLEY: We have one further matter. Mr. Hart will address that for you.

MR. HART: Tampa Electric has filed a motion to compel discovery with regard to a document that was produced and entered into evidence at one of the depositions we took. We filed a motion to compel that. We have not seen it, but we have understood that the motion has been denied. We would like to address the Commission regarding our motion to compel.

CHAIRMAN JABER: What haven't you seen? You haven't seen the order denying your motion to compel?

MR. HART: We haven't seen the order denying the motion to compel. We would like to address the Commission even if we had seen the order. We haven't, but we would like to address the Commission regarding our motion to compel.

CHAIRMAN JABER: Okay. Let me make sure I understand. There is an order denying your motion to compel, so are you asking for reconsideration?

MR. HART: Yes, if there is an order. We have heard there is. If there is one, we would like a motion for reconsideration. If not, we would like to address the full Commission with regard to the motion.

CHAIRMAN JABER: I can tell you there is an order. And I can tell you, you need to get your hands on the order. Because if you are going to argue a motion for reconsideration, it seems to me you need the order.

MR. HART: We couldn't agree more.

CHAIRMAN JABER: Staff, let's make sure all the parties have a copy of that order during the break, and we will entertain whatever motion you may have after the break. Any other preliminary matters?

MR. BUTLER: Chairman Jaber, I believe that -- I'm not sure, Cochran, did you cover the additional stipulations on issues like 14A, which is FPL's issue on the hedging activities in 2002? And I think there is a stipulation. There had been a question about some language FIPUG wanted to have inserted into a common position that would ensure that, to the extent things are audited, there is attention to affiliate issues. I think that has been resolved. And if it has, we would like to add 14A. And I think there are some other issues like it that would be added to the stipulated issues.

MR. KEATING: Right. I did bring that up earlier, and indicated that the Commissioners were provided copies of a two-page document that included those stipulations that were reached after the prehearing order was issued. And I think we may have some additional copies here, as well, that includes the language that was agreed to on Monday. And it was our intent to go through that issue in the course of going through all the FPL issues at the close of evidence at the end of the hearing in terms of making recommendations on those issues.

CHAIRMAN JABER: Okay. Mr. Butler, that may be more efficient, since this doesn't excuse the rest of your witnesses, does it?

MR. BUTLER: No, it does not. No.

CHAIRMAN JABER: Okay. Parties, any other preliminary matters before we take a break?

MS. KAUFMAN: No, ma'am.

CHAIRMAN JABER: Okay. Here is what we are going to do. We are going to take a thirty-minute break. And during that break, Mr. Hart, Mr. Beasley, get with staff. Get a copy of the order you are referring to. We will entertain your motion when we get back on the record.

Ms. Kaufman, you indicated there were a couple of issues you wanted to understand positions further. Get with staff, please.

Staff, take advantage of that thirty-minute break, because the next break we take will be around lunch. Thank you.

(Recess.)

CHAIRMAN JABER: Let's get back on the record. Mr. Hart, where we left it last, you had an order. There is an order denying your motion to compel discovery from FIPUG.

MR. HART: Yes.

CHAIRMAN JABER: And you said you wanted the Commission to entertain that motion. Do you want to clarify what you --

MR. HART: We would like for the Commission to reconsider this order.

CHAIRMAN JABER: What is the basis for your motion for reconsideration?

MR. HART: That it overlooks pertinent Florida law, misapprehends what the nature of the document is.

CHAIRMAN JABER: Okay. Why don't you -- for the benefit of all the Commissioners, why don't you tell us more about the underlying motion, what is in the order, and then all of the appropriate argument you have got for the motion for reconsideration. FIPUG, I will ask you to respond, and then I will ask for a staff recommendation.

MR. HART: Yes, Madam Chairman, I will be happy to do that. This document was produced by an expert witness during the course of a deposition. We were given the document to read, we did, we spent some time reading it before the deposition. We asked specifically if we could look at the document before the deposition, we were told we could. We looked at it, we identified it during the course of the deposition. Counsel clearly knew what the document was. We took a recess and went and read the document, came back and had it marked as an exhibit to the deposition. We would have spent longer with the document, but it wasn't controversial at that point in time as to whether or not we were going to have possession of it.

There was an objection raised, an evidentiary objection, but since there was no objection to our physical possession of it, we assumed that they were making an objection to preserve it for the record, that it wouldn't be admissible at the hearing. We then had the document, looked at it, it sat on the table with the other exhibits. It was available to look at for an extended period of time. Right before the deposition was closed, we took a break to see if we had any additional questions, went out of the room, talked among ourselves, came back to conclude the deposition, and found out that counsel had taken the deposition exhibit from the pile of exhibits and refused to return it. That is how this document came into being.

The witness was asked about the document --

COMMISSIONER DAVIDSON: Let me ask a question there. I assume there is a copy somewhere produced if it was marked as an exhibit with the depo, somewhere with an original deposition.

MR. HART: There wasn't. Counsel physically took the document from the court reporter and refused to return it.

COMMISSIONER DAVIDSON: Was the document marked as confidential during the course of the deposition? Was there agreement that it --

MR. HART: No.

CHAIRMAN JABER: Go ahead.

MR. HART: The document that the witness produced, and the witness described it in her deposition as an analysis of Ms. Jordon's rebuttal testimony, was a ten-page single-spaced typed document entitled -- it is in FIPUG's, I don't want to misstate what they titled this, but it was for the purpose of the deposition, cross-examination, and a motion to strike. It was an analysis prepared by the witness of how the witness intended to testify in her deposition on cross-examination. And I believe it said the witness' -- the witness made the statement that my testimony may be subject to a motion to strike.

COMMISSIONER DAVIDSON: Who was the lawyer on the other side?

MR. HART: There are a number of them. Mr. McWhirter was at the deposition.

COMMISSIONER DAVIDSON: Well, let me just jump in and ask a question now. I mean, I have never witnessed such a thing. I mean, I would view it as highly improper, if I was in a deposition, to actually take a document that was marked as an exhibit and identified at the deposition, hand it to the court reporter to distribute to the other side. I mean, that strikes me as highly improper. I don't have any reference to any sort of rules regulating attorney conduct there, but help me understand why we are in this stage, what transpired?

MR. McWHIRTER: Mr. Davidson, what transpired was there was a subpoena duces tecum to produce all information prepared by the witness in preparation for this hearing. The witness brought two very large blue plastic containers, about 12 cubic feet of documents containing all the evidence she had and everything she had relied upon. At the outset of the hearing, counsel for Tampa Electric went through the documents, and they pulled up this one document which was entitled, "TECO fuel hearing preparation for deposition and cross motions to strike." And I said, "It looks to me like that may be part of attorney/client work product, Mr. Hart." And he said, "Oh, no, with an expert witness we are entitled to get that information." And I said, "Well, you're a smart lawyer, Mr. Hart, and I will rely on what you have to say, but I am going to look up the law while we are proceeding with this deposition."

And during the course he takes this exhibit, he puts a tab on it, and says we will mark this as -- asked the court reporter to mark it as Exhibit 3. At that point I objected because it was attorney privileged information. And during the course of the deposition I read the law. And I found the section cited by Mr. Hart, the Evidence Code Section 90.57, and also the rule he didn't cite, which was 1.280(b)(3), and that clearly distinguishes when an expert witness is there and in possession of attorney work product that that is not subject to discovery.

And there were two documents, one were notes she had taken in a conversation with me, and the typewritten documents were notes she had taken in a telephone conversation with Ms. Kaufman. I read the law, I perceived that what Ms. Hart (sic) had told me was the correct law was not the correct law, and so I took this document which belonged to our witness, not to Tampa Electric, which was not in evidence, but had merely had the court reporter's label on it and it was objected to, back into my possession until the matter could be resolved.

COMMISSIONER DAVIDSON: Well, is it incorrect then to state that if attorney work product is given to an expert and an expert relies on that in the preparation of his or her opinion that that information is still not discoverable, even if it has been relied upon by the expert?

MR. McWHIRTER: We brought our brains over here. Mr. Perry is going to argue the law, but my understanding of the law is even if the witness has in his possession attorney work product, that is not discoverable. And I think that is the precise reading of Section Rule 1.280(b)(3).

COMMISSIONER DAVIDSON: I apologize, I didn't mean to cut TECO off from his argument, but I wanted to sort of jump in and understand the exact circumstances as to how this document got pulled from the stack.

CHAIRMAN JABER: FIPUG, let me let you hold onto that. I do want to get through. The motion we have in front of us today is a motion for reconsideration. But as Commissioner Davidson said, the history is important to bring us up to speed.

MR. HART: It is. And I don't want to belabor small points that don't determine the outcome of the case, but I placed no sticker on the document. The court reporter did. And I cited no authority for Mr. McWhirter, and those were not the provisions that I would have relied on, had I cited authority to him. I believe that I cited to him the well-known general principle that work product given to a testifying expert is not -- that any privilege that attached to it is waived. And I will discuss that in more detail in just a moment. But I think we have about three sort of significant questions, and I actually think --

CHAIRMAN JABER: Hang on, Mr. Hart. So where we are today is the prehearing officer has issued an order denying your motion to compel.

MR. HART: Yes.

CHAIRMAN JABER: And under the reconsideration standard, you need to show a mistake of fact or law.

MR. HART: The mistake of fact is that it was ever work product in the first place. The mistake of law is that it doesn't cite either the cases or the provision of the statute for production of expert witness testimony. And I want to address, first of all, whether or not it is work product. That has been sort of -- it's not addressed in the order.

I would assume that TECO's assertions of what the document are are accepted as true unless we are going to have some review of the document for an independent authority to decide. We have seen it, we have read it, this is not one that we are guessing about. We had suggested that the Hearing Officer or legal counsel for the Commission review this document because, first of all, it is just not work product period. There may be some sections of it that people can argue about work product. We are talking about a ten-page single-spaced document about how the witness is going to testify. It deals with mathematical calculations, and a number of other things, and it is not work product, large portions of it.

The correct procedure, if counsel wanted to assert a privilege, was either redact or identify those portions of the document that they assert were work product and produce the rest of it. It is hard to conceive of how a witness' description of errors in her own testimony, written by her, would constitute work product. It is just not work product. So, therefore, we are entitled to large portions of the document under any circumstances without even talking about work product, we believe. And we believe the way that should be resolved is the Hearing Officer or legal counsel should look at this document. We think people knowledgable on these issues looking at this document would clearly know that it is not work product.

CHAIRMAN JABER: What does constitute work product?

MR. HART: Well, a general standard of work product has to do with mental impressions and strategies of counsel.

CHAIRMAN JABER: Okay. That is what I thought. Let me tell you why I'm asking. In your initial opening, you said the document indicates the analysis of how the witness intended to testify. These are your words, I wrote them down, and could be subject to a motion to strike. That she thought her testimony could be subject to a motion to strike. That sounds like a mental impression or a legal strategy.

MR. HART: Of the witness.

CHAIRMAN JABER: Right.

MR. HART: Not of counsel. Everything the witness -- the witness has no legal strategy. The witness has no work product. The witness -- that's the whole point. When you see work product, it is something prepared by the attorney. This was prepared by the witness. Now, I want to talk -- first of all, I think that is important as to whether or not it is work product. But, second of all, I believe that the general state of the law and the majority opinion of the law in Florida and throughout the country is that you waive work product when you give it to a testifying expert, and I think that is the correct position, and that even if this is work product, it should be produced when given to a testifying expert.

I think this is a big policy decision for the Commission. I think this is an important decision. I think to have a level playing field for all the parties, if you are going to be able to give work product to testifying experts and prevent it from being disclosed, I would hope the Commission would write a clear decision so that all parties would know that they can instruct their witnesses how to testify, tell them what positions to take, and that will not be subject to discovery.

Because if you are going to be allowed to give work product to testifying experts and then prevent discovery, it prevents effective cross-examination, and it prevents finding out the truth of the basis of people's opinions. So you just have to decide as a matter of policy. And I think that is illustrated by the fact that there is a split of opinion in this country about whether or not work product can be given to testifying experts. You can find decisions, mostly older decisions, some recent ones, where courts have held that you can protect work product given to testifying experts. But by far the majority opinion is that you cannot.

And we have cited cases in our brief. We have also given additional cases to counsel, and I would like to discuss Professor Ehrhardt's at Florida State, which is generally considered the father of Florida's Evidence Code, and writes on it frequently, has just written an article within the last few weeks on the subject of giving work product to testifying experts. And I think this addresses the policy decision. Assuming that you have work product, which trumps, the expert witness' right to disclose or requirement to disclose? What is not cited in the order in the final is that Rule 280(b)(3) describes work product, but Section 4 says discovery of facts known. Not facts they intend to use or rely on, but facts they know, that you can discover facts known and opinions held by experts. That wasn't cited in the order, the dispositive portion of the order that described why. It simply cited to Rule 3, that is the general work product protection. It doesn't rely on the exception to work product which is the preparation of trial experts.

But Professor Ehrhardt says that the majority opinion he believes is that -- and the courts are moving to this quickly because of the role of experts throughout litigation in our society, but in balancing the interest of the work product privilege and the requirement to disclose expert testimony, Professor Ehrhardt says by the time of trial it seems that the interest to be balanced are between those of a litigation strategy that is unfolding through expert testimony versus the possibility that the expert is serving as a mouthpiece for the attorney's personal view of the case. And it goes on to say putting work product material relating to the subject of testimony in the hands of a testifying expert can have only two purposes: To inform the expert regarding factual aspects of the litigation that might affect the expert's opinion, or to influence or prompt the expert to adhere to opinions that favors the counsel's legal theory. Neither act of disclosure creates or aids in the creation of legal information.

And he goes on to discuss a number of the recent cases. And we have cited one, too. We gave it to FIPUG and to counsel, a recent case out of New York. Florida's interpretation of the Rules of Civil Procedure follows the federal rules, as everyone knows, and it cites an opinion saying that -- and cites the advisory committee rules, the federal 1993 amendments to the federal rules stating that litigants should no longer be able to argue that materials furnished to their experts in forming their opinions are privileged or otherwise protected. Effective cross-examination, the efficiency of truth seeking process, and actually the maintenance of the integrity of the work product doctrine are how the issue should be decided, and that results in disclosing what the expert has been given to form the basis of their opinion. Attorneys can protect their work product by electing not to disclose it to an expert.

If it is true litigation strategy, if it is your theories of the case that you want to protect because it is developed by you as a lawyer, there is no point in giving it to a testifying expert unless you want to influence their testimony. And the question is whether or not the seeker of truth and the one making the decisions is entitled to know what influenced this witness' testimony. Why is this witness testifying this way. And that is why work product given to a testifying expert happens.

So we think that, first of all, it is not work product, large portions of it are not even arguably work product. Some portions you could argue about whether or not it is work product, if you can decide whether or not it is the witness' thought or counsel's thought. You would have to decide that to know whether or not it is work product.

CHAIRMAN JABER: Has there ever been an allegation that the attorney prepared that document?

MR. HART: No. And they have never disputed that the witness prepared it. It is not handwritten notes taken during a conversation, it is a typed single-space ten-page document. The assertion that a witness wrote down some handwritten notes while we were having a conversation does not make what the witness wrote down work product. First of all, you don't know whether the witness was telling the attorney, or the attorney was telling the witness. It doesn't make it the mental impressions of the attorney because you wrote down notes. Writing down a factual statement, writing down a mathematical calculation does not make it -- does not make it work product. And there has never been any -- in fact, the witness testified at her deposition under oath that she prepared the document.

CHAIRMAN JABER: Okay. And my second question to you is what issue does this information go to? I mean, I'm assuming you believe it is discoverable. Inherent in your argument that there has been a mistake of law is that this information is discoverable and relevant to issue number --

MR. HART: Well, it would be the issues that Ms. Brown is testifying own.

CHAIRMAN JABER: Okay. And those would be --

MR. HART: On Page 8 of the prehearing order I'm advised, not being the issue identification person for our team, she is testifying on 17I, J, K, L, M, N, and O, and Issues 3 and 5.

CHAIRMAN JABER: Okay. So it is your position that it would relate to the issues that we are entertaining this week, not to any of the issues that were deferred?

MR. HART: The majority of her testimony relates to the Gannon issues and whether or not -- how to deal with Gannons coming out of service, what the test should be.

CHAIRMAN JABER: Okay.

MR. HART: And that is what the discussion is about. We think -- so we deal with the issue of whether or not it is work product in the first place. We dealt with the second issue of whether or not if it is work product, and it is a testifying expert, how do you balance the considerations of what you do. And the third issue is waiver. There is two ways that waiver occurs. One waiver is by giving it to somebody and letting them read it, which we think has occurred in this case.

But it also -- and Professor Ehrhardt says in his same article, citing from a recent judicial decision, "We are unable identify, we are unable to perceive what interest would be served by permitting counsel to provide core work product to a testifying expert and then to deny discovery of such material to the opposing party, because any disclosure to a testifying expert in connection with his testimony assumes the privilege for protected material would be made public. Perhaps in a different form, but still made public. There is a waiver to the same extent as any other disclosure." What that means is that when the attorney decides to disclose work product to a testifying expert, they have waived it the same way they would if they gave to us.

CHAIRMAN JABER: Okay. Let me understand. Again, bringing you back. Your focus needs to be on a reconsideration. And do you agree that the prehearing officer did address the waiver issue? I understand you disagree with the result, but --

MR. HART: He addressed the waiver issue as far as it relates to the disclosure at the deposition, although it is not clear from the order that there was an understanding that we left the room with the document and were given time to read it after it was identified that they knew what it was. He does deal with the issue that the disclosure was too brief and that it did not constitute a waiver. He did not deal with the issue of waiver by giving it to a testifying expert.

The issue does not address whether or not, in fact, the underlying information is work product. It doesn't deal with our request that there be an in camera inspection of it if there is confusion about that, and doesn't really deal with the Rules of Civil Procedure having to do with giving, or facts known by testifying experts.

CHAIRMAN JABER: Okay. Any other argument, Mr. Hart?

MR. HART: That would conclude my argument.

CHAIRMAN JABER: FIPUG, your response.

MR. PERRY: Good morning, Commissioners. My name is Timothy Perry, and I will be arguing the motion on behalf of FIPUG.

The first thing I would like to call your attention, of course, is the standard on a motion for reconsideration. There has to be a mistake of fact or law, as we all know. And I believe that what we have heard from Mr. Hart has just been a mere reargument of his earlier motion. And as case law and orders of this Commission have held, mere reargument is not enough to prevail on a motion for reconsideration.

CHAIRMAN JABER: Let me stop you there, Mr. Perry, and you can help us along by addressing these questions. I heard at least two distinct arguments as it relates to mistake of law. One was that the order doesn't address whose work product, if it is a work product, whose work product was it.

So maybe you could expanded on that, whether it was the attorney's or the testifying expert. The second relates to the waiver question not addressed in the order with regard to was there a waiver that took place when the document was given to the testifying expert.

MR. PERRY: And I believe that there are two separate issues. One is whether the document is work product, and on that point I would say that the waiver issue with regards to giving it to the expert falls within the work product argument. The waiver argument is a second one -- is a different one, in my opinion. It relates only to the occurrences which happened at the deposition, and I will go into that now.

First of all, I would like to address Mr. Hart's discussion of the Ehrhardt Law Review article. First of all, there was a fax that was provided to us and to --

COMMISSIONER DEASON: Madam Chairman, I hate to interrupt, but you didn't answer the Chairman's question. And maybe I can ask it. This document, is it or is it not work product? Who prepared it?

MR. PERRY: First of all, it is work product. What it came from was discussions between counsel and the expert witness on counsel's trial strategy and mental impressions of the case. And the title of the article, or the title of the document is TECO fuel hearing, preparation for deposition and cross, motions to strike.

COMMISSIONER DAVIDSON: Let me ask one more time. I think I am very dense, maybe I just missed it. You just answered the question, it is work product, and maybe I did miss this. Who prepared it? Specifically who?

MR. PERRY: Ms. Brown prepared the document from her notes of the conversation with Ms. Kaufman. Her handwritten notes were transcribed into a typewritten document.

COMMISSIONER DAVIDSON: Ms. Brown is the witness, right?

MR. PERRY: That's correct.

COMMISSIONER DAVIDSON: I think I'm really missing something. How is that, notes prepared by a witness attorney work product?

MR. PERRY: And you have to look at Rule 1.280(b)(3). And what that rule specifically says is that the court shall protect against disclosure of the mental impressions, conclusions, opinions, or legal theories of an attorney or other representative of a party concerning the litigation. And I cited the cases in the motion which support that this should not be disclosed, and --

COMMISSIONER DAVIDSON: Ms. Brown, was she the secretary or paralegal for Ms. Kaufman? I mean, doesn't that document reflect her own characterization of what she may believe the attorney's opinions to be? I mean, I will just tell you, in ten years practicing I have never seen an expert witness' notes, a testifying expert witness' notes that relate to his or her testimony deemed to be work product. I have seen the attorney's notes deemed to be work product, but not the expert witness' notes.

MR. PERRY: And I cited to two cases in the motion which address that exact point that you just raised. The first one is the Panzer case where the court held that the expert's trial preparation materials that contained the mental impressions and notes of the attorney should be protected from disclosure. The second was a federal case, the Krisa versus Equitable Life Insurance policy case where the court there held that notes of a telephone conversation between an expert witness and an attorney that encompassed the attorney's mental impressions was not subject to discovery.

I submit to you that if that is not exactly on point, then --

COMMISSIONER DAVIDSON: Let me ask this, did you all --

CHAIRMAN JABER: Commissioner Davidson, can I follow up on that before we lose this train of thought?

COMMISSIONER DAVIDSON: Sure.

CHAIRMAN JABER: Going back to the fundamental question as it relates to a mistake of fact or law, can you agree that the discussion in the prehearing officer's order doesn't go to the point whose product was it? I mean, I keep bringing folks back to that standard, and I need you to stay there. It is a mistake of fact or law. And it seems to me that before we even get to whether there is a mistake of law, can we all agree that the order does not discuss who authored the document?

MR. PERRY: And I would say to that point I would agree that Ms. Brown authored the document.

CHAIRMAN JABER: Okay. Commissioner Davidson, go ahead. I just needed that clear in my mind.

COMMISSIONER DAVIDSON: And I appreciate that, because that is the focus. I have a question sort of outside of that focus. Did you all at least offer a copy of this document to the other side with whatever specific provisions you claim are attorney work product redacted so that the non-work product provisions were produced to the other side?

MR. PERRY: No, I don't believe that we did so.

COMMISSIONER DAVIDSON: Why not?

MR. PERRY: We are going to read you a portion of the transcript. I believe that the reason that we did not do so was because we considered the entire document to be our work product.

COMMISSIONER DAVIDSON: Even that portion that didn't contain the specific mental impressions, conclusions of the attorney?

MR. PERRY: I think the notes that are in the document are from the conversation with Ms. Kaufman, and all of it would be her mental impressions.

CHAIRMAN JABER: I'm comfortable on the mistake of fact issue. Now, let me take you back to the argument on mistake of law and the second question I asked you. With regard to waiver, TECO makes the argument that if, for the sake of argument, it is a work product, there was a waiver that occurred when your attorney allowed the testifying expert to have the information, number one, at the deposition; and, number two, to submit it in the first place. And I ask you the same question, do you agree that the order doesn't talk about that part of the waiver?

MR. PERRY: And I will address the legal analysis of that point. First of all, there is discovery, of course, of expert witnesses facts and opinions that are held. What is not discoverable is the attorney's mental impressions, or another representative's mental impressions, and there is a distinction between the two. Mr. Hart certainly could have asked Ms. Brown any question that he liked about her facts or opinions held, but that is not the core of this document. The core of this document is Ms. Kaufman's mental impressions which she shared with the expert witness. And the cases that I cited in the motion go to that point, that the mere discussion of the attorney's mental impressions or strategy of the case does not require a waiver of that knowledge. And if you look at the cases cited by --

CHAIRMAN JABER: I guess I'm not articulating the question well enough. Mr. Hart says there was a waiver in even allowing the testifying expert to have that information; and, secondly, in disclosing that information initially at the deposition. That is different from the argument in the order that the order addresses with regard to the inadvertent disclosure of the document and taking the document back. I need you to address the argument of waiver that Mr. Hart brought up today.

MR. PERRY: And I guess I'm having a hard time understanding, because I see that -- that waiver issue I see as the work product issue. Is the fact that Ms. Kaufman discussed these issues with Ms. Brown a waiver of the work product? And I would say it is not, and that is the point that I'm trying to make. That in the Rule 1.280(b)(3), an attorney's mental impressions, strategy of a case are protected from disclosure and discovery. And the cases I cited also go to that point, that the telephone conversation and notes made by the expert witness were not allowed in that federal case to be discovered, and also in the Florida case that I cited, the Panzer case, to the extent that an expert witness' trial preparation materials were required to be disclosed in discovery, the court noted specifically that the attorney's mental impressions were to be excluded from the discovery of those materials.

CHAIRMAN JABER: How do you prove that it is the attorney's mental impressions when you have a document that is typewritten and submitted by the testifying expert?

MR. PERRY: Well, I mean, I would submit that -- I mean, Ms. Brown will certainly tell you that. And as her attorney I will tell you that. I don't want to misrepresent the facts of the document. I guess --

CHAIRMAN JABER: Ms. Brown will be able to testify that those were the mental impressions of the attorney?

MR. PERRY: Hold on one second. One way that I would go back to it is if you can just look at the plain language of the rule, 1.280(b)(3).

COMMISSIONER DAVIDSON: That wasn't the Chairman's question. I'm curious about the answer to the Chairman's question before you move on to what you view to be the plain language of the rule.

MR. PERRY: With regards to how do I prove that it is the attorney's mental impression?

CHAIRMAN JABER: How is it that the decision-maker determines that it is the attorney's mental impressions, when it is the testifying expert that has custody of the document? She, apparently, at the deposition testifies that it is her preparation of the document.

MR. PERRY: I believe it's my understanding that in some instances there is an inspection of the document which is allowed, but that goes to the --

CHAIRMAN JABER: Which brings me to my last question. Do you have an objection to our legal counsel inspecting the document?

MR. PERRY: No, we don't.

CHAIRMAN JABER: Commissioners, what's your pleasure? I guess I would need to hear from staff, too. But are you done with your argument?

MR. PERRY: With regards to the inadvertent disclosure at the deposition, I would say that the case law that I cited to in my motion brings up a five-point argument. And, first of all, the document did not even fall within the scope of what they requested in their subpoena dues tecum, and really Ms. Brown was not required to bring the document at all. It was only inadvertently that she had done so.

And as Mr. McWhirter had discussed before, he had objected to the document preliminarily and accepted Mr. Hart's characterization, subject to check. He objected when the document was marked as an exhibit, and he objected at the conclusion of the deposition as well as taking back custody of the document. So it was clearly his intent to prevent the disclosure of the document, subject to check on the law, and any disclosure thereof wasn't a waiver of the work product of the document.

CHAIRMAN JABER: Staff, what's your recommendation, and then I'm sure we will have questions for you?

MR. KEATING: I'm going to give this a shot. I'm hearing a lot of this new, as well, at the same time you are hearing it, and trying to determine whether it satisfies the standard for a motion for reconsideration. I think the Commissioners have asked some good questions that I think will get to the base of the issue of whether this is discoverable work product.

And the question that has to be answered, I think, in my mind is was this material that was prepared by the expert or was it prepared by the attorney. If it is information from the attorney, I think it is our understanding of the law that if it was prepared by the attorney, and based on case law that FIPUG has cited, and it contains the -- I'm sorry, if it contains the mental impressions, conclusions, opinions, or legal theories of an attorney concerning the litigation that is contained in the expert witness trial preparation materials, it would still be considered work product.

CHAIRMAN JABER: Well, let me ask you a question in that regard. The order does not clarify whether it was prepared by the attorney or whether it was prepared by the testifying expert. But there is consensus that the document -- consensus this morning that the document was prepared by the testifying expert, as opposed to some letter she may have received from Mr. McWhirter or Ms. Kaufman. That is not what we have here. We have a ten-page typed paper, apparently, that she acknowledges was prepared by her. So how does that factor into your recommendation?

MR. KEATING: Again, I think it is my understanding of the law that if it contains the mental impressions or theories of the attorney, that at least those portions of the document would be protected as work product privilege.

CHAIRMAN JABER: Would an inspection help you give us a recommendation in that regard?

MR. KEATING: That may. But, again, I think you raised the point that it is going to be difficult to determine that simply from looking at the document. To an extent, what we had to rely upon was the word of FIPUG that this was the basis for the document.

CHAIRMAN JABER: Have you ever reviewed the document to see if there is any notation, footnote, disclaimer that portions of the document were prepared by the attorney?

MR. KEATING: I have never reviewed a document for that purpose before.

CHAIRMAN JABER: Well, that's not what I'm asking.

MR. KEATING: I'm sorry.

CHAIRMAN JABER: As we sit here today, that document, have you looked at that document to determine whether there were any notations, footnotes that indicate portions or the entire document were prepared by Ms. Kaufman or Mr. McWhirter?

MR. KEATING: No, I have not.

CHAIRMAN JABER: Commissioners, I will tell you where I am. If we have to make a decision today, I am leaning toward finding that there was a mistake of fact or law such that the document should be disclosed. But in an abundance of caution, I would like to go ahead and give staff an opportunity to look at the document and make sure that those disclosures, the disclaimers I have referenced are not there.

I heard Mr. Hart acknowledge that legal counsel's inspection of that document is sufficient. I have heard Mr. Perry say they have no objection to that kind of inspection. I would like to err on the side of caution and give staff that opportunity. Commissioner Davidson.

COMMISSIONER DAVIDSON: Thank you, Chairman. And I agree with all of your comments there. I've got a couple of additional questions for FIPUG. Were the cases that you cited pre-1993 revisions to the federal rules, or post-1993 revisions?

MR. PERRY: The federal case was a 2000 case, and the Florida case was, I believe, a 1980 case.

MR. HART: Commissioners, I might be able to help with that.

COMMISSIONER DAVIDSON: Let me go ahead and get the answer from -- it was 19 what?

MR. PERRY: '80, the Panzer case.

COMMISSIONER DAVIDSON: Do you understand the distinction in this debate between fact work product and opinion work product?

MR. PERRY: I do.

COMMISSIONER DAVIDSON: And is it your contention that everything in that document, every sentence is opinion work product and that there is no fact work product?

MR. PERRY: It is my understanding that the document contains opinion work product about the strategy of the case, and the strategy for hearing, and the strategy for deposition, and the strategy for cross-examination.

COMMISSIONER DAVIDSON: Have you seen the document?

MR. PERRY: Yes, I have.

COMMISSIONER DAVIDSON: Well, I'm asking you. In your understanding, does the document contain only opinion work product or does it contain both opinion and fact work product? And keeping in mind that we are going to have staff -- I would like staff to make that assessment, also.

MR. PERRY: Can I take a second to look at the document one more time to make that --

COMMISSIONER DAVIDSON: Sure. But prior to that, let me ask, do you agree that even in the pre-1993 line of cases that fact work product in the possession of a testifying expert was generally discoverable? That the debate in the pre-1993 revision centered upon opinion work product.

MR. PERRY: Yes, I understand that there is a distinction between the -- there is generally a more liberal treatment towards fact work product, because it has to do with the facts of the case, as opposed to opinion work product which contains the mental impressions, so on and so forth.

COMMISSIONER DAVIDSON: And I've got one more question, Chairman. Let me find it right here, and that is Professor Ehrhardt's characterization, or statement that the new Rule 1.280(b)(3) subordinates its general work product discovery language in deference to the more specific provisions of 1.280(b)(4) governing discovery of facts known and opinions held by experts, and then gives a string of citations. Is it your contention that that statement of the post-1993 revisions to the federal rules is incorrect?

MR. PERRY: First of all, I haven't seen that article before. It was not provided to me. Second of all, it was not included in counsel's motion. But to address your point of what my understanding is, if I remember, I think Mr. Hart said that Professor Ehrhardt cites to several federal cases, and that there is a split of opinion between the various federal circuits with regards to this issue, some having more liberal treatment, some having more protective treatment.

COMMISSIONER DAVIDSON: All right. And that's fine. That was my last question. I will just close my comments with a comment that I am fundamentally troubled by an attorney pulling out an exhibit that has been marked during a deposition, notwithstanding all the arguments surrounding it. In my own view, it's not proper to do that.

I understand that it was in there inadvertently and you relied on counsel, but once it is marked as a deposition exhibit, it is an exhibit to that deposition. It is part of that deposition. And no party in any case can unilaterally just remove a document like that. I mean, if there is an issue, bring it to the Commission's attention ASAP and protect your rights as much as you can with a letter to opposing counsel. But don't self-help yourself to a document that has been marked during the course of a deposition.

CHAIRMAN JABER: Commissioners, we don't get to Ms. Brown's testimony for quite awhile, I think having looked at the list of witnesses in the prehearing order, so what I would like to do is allow staff an opportunity to inspect that document, I heard for two things. One, I want you to tell me if you can base your recommendation based on some review of the document that indicates they were, in fact, the attorney's mental impressions. And, Mr. Keating, frankly, I'm looking for some sort of disclaimer, notation, footnote, something like that. And what I heard Commissioner Davidson say is he would like you to review the document also for a recommendation as to whether it looks like it is fact testimony or opinion testimony.

Commissioner Davidson, have I characterized that correctly? Okay. Do that during lunch. We will take this up as a matter right after lunch.

Mr. Hart, you had something to say?

MR. HART: The only thing I wanted to discuss very briefly was the cases cited.

CHAIRMAN JABER: We are done with argument, Mr. Hart.

MR. HART: Ma'am?

CHAIRMAN JABER: We're done with argument.

MR. HART: I was going to agree with FIPUG, but I won't.

CHAIRMAN JABER: You know, as much as I want to give you that opportunity, we are done with argument.

Staff, are you clear on what you need to do?

MR. KEATING: I believe so, yes.

CHAIRMAN JABER: Okay. And, Ms. Kaufman, you were going to take an opportunity during the last break to talk to staff about Issues 30 and 31A. (Pause.)

As I recall, Ms. Kaufman, there were some --

MS. KAUFMAN: I'm sorry, Madam Chair, I didn't know if you were waiting for me.

CHAIRMAN JABER: I am. As I recall, there were some changes in positions for 30 and 31A, and you wanted time to think about --

MS. KAUFMAN: Yes. And I think it might be more appropriate for the staff to brief you on where we are on those issues first.

CHAIRMAN JABER: Okay. Go ahead, Mr. Keating.

MR. KEATING: We mentioned earlier that since the prehearing order was issued, actually just this morning reached agreement with FPL on their position on a couple of issues that are affected by the testimony of Staff Auditor Kathy Welch.

What we discussed during the break was whether we could stipulate her testimony into the record, as well as FPL's rebuttal to her testimony. I think what we decided as far as the cleanest method to handle that would be for staff to withdraw Ms. Welch's testimony, and FPL would agree to withdraw its rebuttal testimony to Ms. Welch.

CHAIRMAN JABER: Okay. So we should acknowledge that the prefiled testimony of Kathy Welch has been withdrawn by staff. And, FPL, this affects the prefiled rebuttal testimony of Ms. Dubin?

MR. BUTLER: That's right, yes.

CHAIRMAN JABER: And you are withdrawing her prefiled rebuttal testimony?

MR. BUTLER: Yes, we would agree to withdraw it in conjunction with the rewithdrawal of Ms. Welch's testimony.

CHAIRMAN JABER: Okay. Let the record reflect acknowledgment that the prefiled rebuttal testimony of K. Dubin has been withdrawn.

MS. KAUFMAN: Chairman, I think that, again, if I'm not mistaken, Issue 30 is still pending. However, on Issue 31 with Ms. Welch's testimony withdrawn, we will just have to take no position on that issue.

CHAIRMAN JABER: Thank you, Ms. Kaufman.

Staff, 31A looks like you have a stipulation.

MR. BUTLER: Chairman Jaber, I'm sorry, I think we are talking about 32A.

MS. KAUFMAN: I'm sorry. You're correct, Mr. Butler.

CHAIRMAN JABER: And, again, on Issue 32A, then, you have a stipulation.

MR. KEATING: I believe that's correct, yes.

CHAIRMAN JABER: And we have left all of the FPL proposed stipulations until the end of the case.

MR. KEATING: Correct. And, I'm sorry, I didn't mean to interrupt, but a couple of other things before we take a break. During our break we have determined that, I believe, Staff Witness Joseph Rohrbacher could be excused as no parties have questions for Mr. Rohrbacher, and that his testimony could be moved into the record.

CHAIRMAN JABER: Have you checked with all the parties?

Mr. Twomey, come to the microphone. You have questions for Mr. Rohrbacher?

MR. TWOMEY: Yes, ma'am, I do.

CHAIRMAN JABER: Okay. You need to remember to check with all the parties.

MR. KEATING: I forgot Mr. Twomey simply because he intervened very recently on this issue.

CHAIRMAN JABER: I understand. You just need to remember to check with all the parties. What else?

MR. KEATING: I believe that's it.

CHAIRMAN JABER: Okay. If you're a witness in this case and you're in the room, please stand and raise your right hand.

(Witnesses collectively sworn.)

CHAIRMAN JABER: By my list we're got Ms. Dubin being the first witness, is that correct?

MR. BUTLER: That's right. Are we proceeding with her now?

CHAIRMAN JABER: She's the first witness. Is there anything else?

MR. BUTLER: No, there isn't. I just didn't know if you wanted to do it before lunch.

CHAIRMAN JABER: We are going to go with Ms. Dubin.

MR. BUTLER: Then I would call Ms. Dubin to the stand.

CHAIRMAN JABER: See, this is what happens when I put on the record that we're going to take a lunch break, Commissioners. Commissioner Baez already reminded me.

KOREL M. DUBIN

was called as a witness on behalf of Florida Power and Light Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BUTLER:

Q Ms. Dubin, would you please state your name and address for the record?

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

Q And, Ms. Dubin, do you have -- indulge me, Madam Chairman, there are several testimonies. It's going to take me a minute to run through what we have here.

Do you have before you, Ms. Dubin, prepared testimony in this docket dated April 1, 2003, entitled, "Levelized Fuel Cost-recovery and Capacity Cost-recovery Final True-up, January 2002 through December 2002," consisting of 9 pages?

A Yes, I do.

Q And attached to that are your documents KMD-1 and 2, correct?

A Yes.

Q And do you have before you prepared testimony dated August 12, 2003, entitled, "Estimated Actual True-up, January 2003 through December 2003," consisting of 14 pages?

A Yes.

Q And attached to it are documents identified as KMD-3 and 4, correct?

A Yes.

Q Do you have before you prepared testimony dated September 12, 2003, that is entitled, "Testimony of Korel M. Dubin," and it covers FPL's projections for 2004?

A Yes.

Q And that consists of 14 pages and has attached to it documents KMD-5 and 6, correct?

A That's correct.

Q And, finally, do you have before you prepared testimony dated November 3, 2003, entitled, "Supplemental Testimony of Korel M. Dubin," consisting of four pages with no attached exhibit?

A Yes.

Q Do you have any corrections to make to your prepared testimony or exhibits?

A No, I do not.

Q Do you adopt this prepared testimony as your testimony in this proceeding?

A Yes, I do.

Q I would ask that an exhibit number be assigned to Ms. Dubin's documents collectively. I think that would be Number 13?

CHAIRMAN JABER: It is, but it is KMD-1 through what?

MR. BUTLER: KMD-1 through 6.

CHAIRMAN JABER: Okay. KMD-1 through 6 will be identified as Composite Exhibit 13.

(Composite Exhibit 13 marked for identification.)

BY MR. BUTLER:

Q Would you please summarize your testimony, Ms. Dubin?

A Yes.

CHAIRMAN JABER: Mr. Butler, I'm sorry, let me indicate for the record that the prefiled testimony of Korel M. Dubin filed April 1st, filed August 2nd, filed September 12th, and filed November 3rd shall be inserted into the record as though read.

MR. BUTLER: Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 030001-EI

April 1, 2003

Q. **Please state your name, business address, employer and position.**

A. My name is Korel M. Dubin, and my business address is 9250 West Flagler Street, Miami, Florida, 33174. I am employed by Florida Power & Light Company (FPL) as the Manager of Regulatory Issues in the Regulatory Affairs Department.

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

A. Yes, I have.

Q. **What is the purpose of your testimony in this proceeding?**

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery Clause (FCR) and Capacity Cost Recovery Clause (CCR) Net True-Up amounts for the period January 2002 through December 2002. The Net True-Up for the FCR is an under-recovery, including interest, of $72,467,176. This FCR true-up under-recovery of $72,467,176 has been included in the Midcourse Correction FCR factors effective April 2, 2003 that were approved by the Commission on March 4,

2003. The Net True-Up for the CCR is an over-recovery, including interest, of $12,676,723. I am requesting Commission approval to include this CCR true-up over-recovery of $12,676,723 in the calculation of the CCR factor for the period January 2004 through December 2004.

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

A. Yes, I have. It consists of two appendices. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules. FCR Schedules A-1 through A-9 for the January 2002 through December 2002 period have been filed monthly with the Commission and served on all parties. These schedules are incorporated herein by reference.

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

A. Unless otherwise indicated, the data are taken from the books and records of FPL. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

FUEL COST RECOVERY CLAUSE (FCR)

Q. Please explain the calculation of the Net True-up Amount.

A. Appendix I, page 3, entitled "Summary of Net True-Up", shows the calculation of the Net True-Up for the period January 2002 through December 2002, an under-recovery of $72,467,176. The calculation of the true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision".

The actual End-of-Period under-recovery for the period January 2002 through December 2002 of $79,514,964 is shown on line 1. The estimated/actual End-of-Period under-recovery for the same period of $7,047,788 is shown on line 2. This amount was included in the calculation of the FCR factor for the period January 2003 through December 2003. Line 1 less line 2 results in the Net True-Up for the period January 2002 through December 2002 shown on line 3, an under-recovery of $72,467,176. This amount was included in the Midcourse Correction FCR factors effective April 2, 2003 approved by the Commission on March 4, 2003.

Q. Have you provided a schedule showing the variances between actuals and estimated/actuals?

A. Yes. Appendix I, page 6 shows the actual fuel costs and revenues compared to the estimated/actuals for the period January 2002 through December 2002.

Q. What was the variance in fuel costs?

A. The final under-recovery of $72,467,176 for the period January 2002 through December 2002 is primarily due to an $86.9 million or 3.6% increase in Total Fuel Costs and Net Power Transactions (Appendix I, page 6, line A7) offset by a $9.4 million or 0.4% higher than projected Jurisdictional Fuel Revenues (Appendix I, page 6, line C3).

The $86.9 million variance in Jurisdictional Fuel Costs and Net Power Transactions is primarily due to a $60.8 million or 3% increase in the Fuel Cost of System Net Generation, a $19 million increase in Fuel Cost of Purchased Power, a $4.1 million increase in Energy Payments to Qualifying Facilities, and a $5.1 million increase in the Energy Cost of Economy Purchases. These amounts are offset by a $3 million variance in the Fuel Cost of Power Sold and a $1.5 million variance in Gains from Off-System Sales.

The $60.8 million or 3% increase in the Fuel Cost of System Net Generation is primarily due to higher than projected Net Energy for Load in the months of October and November, which in turn resulted from hotter than normal weather. The higher Net Energy for Load caused FPL to use 9% more heavy oil and 11% more purchased power than projected. As reported on the December 2002 A3 Schedule, the $60.8 million variance is primarily made up of a $74 million or 12.4% heavy oil variance offset by a ($17.8 million) or

(1.5%) natural gas variance. Oil was $0.11 per MMBtu or 3.1% higher than projected. Natural gas was $0.10 per MMBtu or 2.6% higher than projected.

Q. What was the variance in retail (jurisdictional) Fuel Cost Recovery revenues?

A. As shown on Appendix I, page 6, line C1, actual jurisdictional Fuel Cost Recovery revenues, net of revenue taxes, were $9.4 million or 0.4% higher than the estimated/actual projection. This increase was due to higher than projected jurisdictional sales, which were 368,634,241 kWh or 0.4% higher than the estimated/actual projection.

Q. How is Real Time Pricing (RTP) reflected in the calculation of the Net True-up Amount?

A. In the determination of Jurisdictional kWh sales, only kWh sales associated with RTP baseline load are included, consistent with projections (Appendix I, page 6, Line C3). In the determination of Jurisdictional Fuel Costs, revenues associated with RTP incremental kWh sales are included as 100% Retail (Appendix I, page 6, Line C4c) in order to offset incremental fuel used to generate these kWh sales.

Q. What is the appropriate final benchmark level for calendar year 2003 for gains on non-separated wholesale energy sales eligible for a shareholder incentive as set forth by Order No. PSC-00-1744-PAA-EI, in

Docket No. 991779-EI?

A. For the year 2003, the three year average threshold consists of actual gains for 2000, 2001, and 2002 (see below) resulting in a three year average threshold of $21,657,720. Gains on sales in 2003 are to be measured against this three year average threshold.

2000	$37,400,076
2001	$17,846,596
2002	$9,726,487
Average threshold	$21,657,720

CAPACITY COST RECOVERY CLAUSE (CCR)

Q. Please explain the calculation of the Net True-up Amount.

A. Appendix II, page 3, entitled "Summary of Net True-Up Amount" shows the calculation of the Net True-Up for the period January 2002 through December 2002, an over-recovery of $12,676,723, which I am requesting to be included in the calculation of the CCR factors for the January 2004 through December 2004 period.

The actual End-of-Period over-recovery for the period January 2002 through December 2002 of $56,420,197 (shown on line 1) less the estimated/actual End-of-Period over-recovery for the same period of $43,743,474, (shown on line 2) results in the Net True-Up over-recovery for the period January 2002 through December 2002 (shown on line 3) of $12,676,723.

Q. Have you provided a schedule showing the calculation of the End-of-Period true-up?

A. Yes. Appendix II, pages 4 and 5, entitled "Calculation of Final True-up Amount", shows the calculation of the CCR End-of period true-up for the period January 2002 through December 2002. The End-of-Period true-up shown on page 5, column 13, line 17 plus line 18 is an over-recovery of $56,420,197.

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

A. Yes it is. The calculation of the true-up amount follows the procedures established by this Commission as set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

Q. Have you provided a schedule showing the variances between actuals and estimated/actuals?

A. Yes. Appendix II, page 6, entitled "Calculation of Final True-up Variances", shows the actual capacity charges and applicable revenues compared to the estimated/actuals for the period January 2002 through December 2002.

Q. What was the variance in net capacity charges?

A. As shown on line 7, actual net capacity charges on a Total Company basis were $9.7 million lower than the estimated/actual projection. This variance was primarily due to $6.2 million lower than expected Payments to Non-Cogenerators and $3.9 million lower than expected payments to Cogenerators. The $6.2 million lower than expected Payments to Non-Cogenerators is primarily due to lower than projected capacity payments to SJRPP during October through December 2002. JEA refinanced to obtain a lower interest rate on its callable debt of some of its outstanding bonds during the last quarter of 2002. FPL's capacity payments to JEA are based in part on JEA's cost of debt, so this caused a decrease in the capacity payments. The $3.9 million lower than expected payments to Cogenerators are primarily due to lower than projected capacity payments to Cedar Bay and Indiantown during October through December 2002. FPL's capacity payments to these Cogenerators are based in part on their achieved capacity factors, which were lower than projected.

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

A. As shown on line 12, actual Capacity Cost Recovery revenues, net of revenue taxes, were $3 million or 0.5% higher than the estimated/actual projection. This increase was due to higher than projected jurisdictional sales, which were 368,634,241 kWh or 0.4% higher than the estimated/actual projection.

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. 030001-EI

August 12, 2003

Q. Please state your name and address.

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

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

A. I am employed by Florida Power & Light Company (FPL) as Manager, Regulatory Issues in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the calculation of the Estimated/Actual True-up amounts for the Fuel Cost Recovery Clause (FCR) and the Capacity Cost Recovery Clause (CCR) for the period January 2003 through December 2003.

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

A. Yes, I have. It consists of various schedules included in Appendices I and II. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules.

FCR Schedules A-1 through A-9 for January 2003 through June 2003 have been filed monthly with the Commission, are served on all parties and are incorporated herein by reference.

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

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

Q. Please describe what data FPL has used as the "baseline" for calculating the FCR and CCR true-ups that are presented in your testimony.

A. The Commission has approved two mid-course corrections for FPL's FCR factors this year. For FCR, the true-up calculation therefore compares estimated/actual data consisting of actual data for January through June 2003 and revised estimates for July through December 2003 with the data that was filed in FPL's midcourse correction filings (consisting of actual data for January through May and estimates for June through December based on FPL's February 17, 2003 midcourse correction filing). For CCR the true-up calculation compares estimated/actual data consisting of actuals for January through June 2003 and revised estimates for July through December 2003, with the original estimates for January through December 2003 filed on November 4, 2002.

Q. Please explain the calculation of the Interest Provision that is applicable to the FCR and CCR true-ups.

A. The calculation of the interest provision follows the same methodology used in calculating the interest provision for the other cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount times the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the 30 day commercial paper rate as published in the Wall Street Journal on the first business day of the current and subsequent months. The average interest rate for the projected months is the actual rate as of the first business day in July 2003.

FUEL COST RECOVERY CLAUSE

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

A. Appendix I, pages 2 and 3, show the calculation of the FCR Estimated/Actual True-up amount. The calculation of the estimated/actual true-up amount for the period January 2003 through December 2003 is an under-recovery, including interest, of $344,729,859 (Appendix I, Page 3, Column 13, Line C11).

Appendix I, pages 2 and 3 also provide a summary of the Fuel and Net Power Transactions (lines A1 through A7), kWh Sales (lines B1 through B3), Jurisdictional Fuel Revenues (line C1 through C3), the True-up and Interest Provision for this period (lines C4 through C10), and the End of Period True-up amount (line C11).

The data for January 2003 through June 2003, columns (1) through (6) reflects the actual results of operations and the data for July 2003 through December 2003, columns (7) through (12), are based on updated estimates.

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

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

A. Yes, they were.

Q. Please summarize the variance schedule provided as page 4 of Appendix I.

A. The variance calculation of the Estimated/Actual data compared to the midcourse correction projections for the January 2003 through December 2003 period is provided in Appendix I, Page 4. FPL's midcourse correction filing dated June 13, 2003 projected Total Fuel and Net Power Transactions to be $3.1164 billion for January through December 2003 (actual data for January through May and estimates for June through December based on FPL's February 17, 2003 midcourse correction filing) (See Appendix I, page 4, Column 2, Line C6). The estimated/actual projected Jurisdictional Total Fuel Cost and Net power Transactions is now projected to be $3.4699 billion for the period January through December 2003 (Actual data for January through June 2003 and revised estimates for July through December 2003) (See Appendix I, Page 4, Column 1, Line C6). Therefore, Jurisdictional Total Fuel Cost and Net Power Transactions are $353.5 million higher than projected. (See Appendix I, Page 4, Column 3, Line C6)

Jurisdictional Fuel Revenues for 2003 are $8.9 million higher than projected (Appendix I, Page 4, Column 3, Line C3) due to higher than projected kWh sales in the month of June 2003. The $353.5 million of higher costs less the $8.9 of higher revenues, plus interest, result in the $345 million under-recovery.

Please note that the final under-recovery of $72,467,176 for the period ending December 2002 was included in the midcourse correction that became effective in April 2003 and, therefore, is not reflected in the $344,729,859 estimated/actual true-up amount to be carried forward to the 2004 fuel factors.

Q. Please explain the variances in Total Fuel Costs and Net Power Transactions.

A. As shown on Appendix I, page 4, line C6, the variance in Total Fuel Costs and Net Power Transactions is $353.5 million or an 11.3% increase from projections.

This variance is mainly due to:

- A $303.7 million or 10.9% increase in the Fuel Cost of System Net Generation due primarily to higher than projected residual oil and natural gas costs. Natural gas costs are currently projected to be $220 million higher than the midcourse correction filing. The unit cost of natural gas in the estimated/actual period is $6.52 per MMBTU or $.67 (11.4%) higher than the $5.85 per

MMBTU included in the midcourse correction. Residual oil costs are currently projected to be $86 million higher than the midcourse correction filing. The unit cost of residual oil in the estimated/actual period is $4.42 per MMBTU or $0.16 (3.7%) higher than the $4.27 per MMBTU included in the midcourse correction.

- A $36.1 million increase in Fuel Cost of Purchased Power due to a 9.8% increase in the unit cost paid for energy and 6.3% greater than projected purchases.
- A $19.5 million increase in Energy Payments to Qualifying Facilities due to 460,871 MWh or 7.2% greater than projected QF purchases and 7.9% higher unit cost paid for the energy.
- A $16.9 million increase in the Energy Cost of Economy Purchases due to 426,077 MWh or 29% greater than projected economy purchases.

These amounts are offset by an $18.8 million increase in Fuel Cost of Power Sold, which is primarily due to selling 184,812 MWh or 9.2% more than projected at a 20.7% higher than projected unit cost.

Q. Please describe the incremental hedging costs as shown on Appendix I, page 4, Lines A1b.

A. Incremental hedging O&M costs for 2003 are currently expected to be $385,994 or about $33,554 less than originally projected. Since the Commission's decision in Docket No. 011605-EI, FPL has been acquiring new systems and personnel for the purpose of expanding and enhancing its capabilities to implement a more robust hedging program. Those systems and personnel now are largely in place. Our hedging plan going forward reflects these incremental capabilities.

Q. What is the appropriate estimated benchmark level for calendar year 2004 for gains on non-separated wholesale energy sales eligible for a shareholder incentive as set forth by Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI?

A. For the forecast year 2004, the three year average threshold consists of actual gains for 2001, 2002, and January through June 2003, and estimates for July through December 2003 (see below). Gains on sales in 2004 are to be measured against this three year average threshold, after it has been adjusted with the true-up filing (scheduled to be filed in April 2004) to include all actual data for the year 2003.

2001	$17,846,596
2002	$ 9,726,487
2003	$13,091,111
Average threshold	$13,554,731

CAPACITY COST RECOVERY CLAUSE

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

A. The Estimated/Actual True-up for the period January 2003 through December 2003 is an over-recovery of $16,048,425 including interest (Appendix II, Page 3, Column 13, Lines 17 plus 18). Appendix II, Pages 2-3 shows the calculation supporting the CCR Estimated/Actual True-up amount.

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

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

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

A. Yes. Appendix II, Page 4, shows the Estimated/Actual capacity charges and applicable revenues (January through June 2003 reflects actual data and the data for July through December 2003 is based on updated estimates) compared to the original projections for the January 2003 through December 2003 period.

Q. What is the variance related to capacity charges?

A. As shown in Appendix II, Page 4, Column 3, Line 13, the variance related to capacity charges is a \$2.1 million (0.3%) decrease. The primary reasons for this variance is a \$12.2 million decrease in payments to non-cogenerators, a \$1.3 million decrease in short-term capacity payments, and a \$1.1 million increase in Revenues from Capacity Sales, offset by a \$6.1 million increase in payments to cogenerators, a \$2.2 million increase in Transmission of Electricity by Others, and \$5.6 million increase in Incremental Power Plant Security Costs.

The \$12.2 million decrease in payments to non-cogenerators is primarily due to lower than estimated payments to Southern Company and SJRPP. The \$1.3 million decrease in short-term capacity payments is primarily due to lower than estimated Short Term Purchases. The \$1.1 million increase in Revenues from Capacity Sales is due to more than projected Capacity Sales. The \$2.2 million increase in Transmission of Electricity by Others is due to higher than originally projected purchased power. The \$6.1 million increase in payments to cogenerators is primarily due to the implementation of Cedar Bay Amendment No. 1 as approved by Order No. PSC-03-0157-PAA-EI.

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

A. As shown on Appendix II, Page 4, Column 3, Line 16, Capacity Cost Recovery revenues, net of revenue taxes, are $13.5 million higher than originally projected due to higher than projected kWh sales. The $13.5 million higher revenues plus the $2.1 million lower costs, plus interest, results in the true-up amount of $16 million over-recovery (Appendix II, Page 4, Column 3, Lines 17 plus 18). The estimated/actual 2003 over-recovery of $16 million plus the final 2002 over-recovery of $12.7 million filed on April 1, 2003 results in an over-recovery of $28.7 million to be carried forward to the 2004 capacity factor.

Q. Please describe the $5.6 million increase in Incremental Power Plant Security Costs as shown on Appendix II, page 4, Line 3.

A. In providing its initial estimate of the expected incremental power plant security costs, FPL indicated that there were significant uncertainties in its projection of these costs in light of the need for FPL to take proactive measures in response to changing threat levels. Further, FPL recognized the potential for additional government-mandated requirements in response to those threats.

On April 29, 2003, the Nuclear Regulatory Commission (NRC) issued three new security-related orders: Order Nos. EA-03-038, EA-03-039 and EA-03-086. These orders require nuclear power plants to further enhance security. They build on the changes required by Order EA-02-026 issued on February 25, 2002, and relate to additional security personnel, training, and equipment. Details on these new security measures cannot be disclosed because such details have been determined to be "Safeguards Information" by the NRC, thereby prohibiting public disclosure of such details. FPL is in the process of complying with the April 29, 2003 orders and will continue implementing its compliance measures into 2004.

In addition to the new nuclear power plant security costs, approximately $120,000 of the $5.6 million variance is attributable to increases in incremental security costs related to the fossil power plants. Originally the fossil power plant security cost estimates only included the cost of security guards at certain locations. The $120,000 variance is caused by increased security measures for incremental fossil power plant security required by a recent Coast Guard rule and/or recommendations from the Department of Homeland Security authorities. These incremental fossil power plant security expenses include the cost of items such as gates, cameras, and access card readers. Additionally, temporary off-duty police officers were deployed during national threat level increases.

Q. Some of the incremental power plant security expenses are for the replacement of existing components that do not meet

present security requirements. When replacements occur, how are they accounted for?

A. Under standard accounting practices and consistent with the Property Retirement Unit Catalog (PRUC), these power plant security items are considered to be additions and replacements of "minor items" of property. Consistent with accepted accounting principles, where there is an addition or replacement of a minor item of property but an entire system is not being replaced, the new item is recorded as an O&M expense and no further adjustment is made. This same procedure applies whether recording the expense in base or an adjustment clause recoverable account. Therefore, FPL has included the total cost of these incremental power plant security items in its CCR clause calculation.

Q. Are the power plant security costs that FPL has included in its CCR calculation incremental costs?

A. Yes. FPL's incremental power plant security costs are discrete, truly incremental costs. They are tracked and segregated by account 524.220 for nuclear power plants and account 506.075 for fossil power plants. The 2002 Minimum Filing Requirements (MFRs) filed in Docket No. 001148-EI do not include any of the incremental power plant security costs as a result of 9/11/01 or other Homeland Security responses that FPL has included for recovery through the capacity clause. On November 9, 2001, FPL filed adjustments to its 2002

MFRs to reflect the impact of the 9/11/01 events. However, the footnote on Attachment 1 of this filing stated that the adjustments "Reflects recovery of additional security costs through the fuel clause as filed 11/05/2001 in Docket 010001-EI." The "additional security costs" reflected in the fuel clause were the initial estimate of the costs of power plant security. Thus, from the outset the incremental power plant security costs as a result of 9/11/01 and other Homeland Security responses have been accounted for and recovered through the adjustment clauses and are not reflected in base rates.

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. 030001-EI

September 12, 2003

Q. Please state your name and address.

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

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Regulatory Issues in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the Fuel Cost Recovery factors (FCR) and the Capacity Cost Recovery factors (CCR) for the Company's rate schedules for the period January 2004 through December 2004. The calculation of the fuel factors is based on projected fuel cost, using the forecast as described in the testimony of FPL Witness Gerard Yupp, and operational data as set forth in Commission Schedules E1 through E10, H1 and other exhibits filed in this proceeding and data previously approved by the Commission. Additionally, my testimony addresses several issues related to security costs and incremental hedging expenses raised by Staff in their Preliminary List of Issues dated July 31, 2003. My testimony also describes the basis for requesting recovery of the cost of additional railcars at the Scherer Plant, presented in the testimony of FPL witness Gerard Yupp, through the Fuel Cost Recovery Clause. I am also providing projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten year projection of Florida Power & Light Company's annual generation mix and fuel prices.

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

A. Yes, I have. It consists of Schedules E1, E1-A, E1-C, E1-D E1-E, E2, E10, H1, and pages 8-9 and 68-69 included in Appendix II and the entire Appendix III. Appendix II contains the FCR related schedules and Appendix III contains the CCR related schedules.

FUEL COST RECOVERY CLAUSE

Q. What is the proposed levelized fuel factor for which the

Company requests approval?

A. 3.742¢ per kWh. Schedule EI, Page 3 of Appendix II shows the calculation of this twelve-month levelized fuel factor. Schedule E2, Pages 10 and 11 of Appendix II indicates the monthly fuel factors for January 2004 through December 2004 and also the twelve-month levelized fuel factor for the period.

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

A. Yes. Schedule E1-D, Page 6 of Appendix II, provides a twelve-month levelized fuel factor of 4.081¢ per kWh on-peak and 3.591¢ per kWh off-peak for our Time of Use rate schedules.

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

A. Yes.

Q. What is the true-up amount that FPL is requesting to be included in the fuel factor for the January 2004 through December 2004 period?

A. FPL is requesting to include a net true-up under-recovery of $344,729,859 in the fuel factor for the January 2004 through December 2004 period. This $344,729,859 under-recovery represents the estimated/actual under-recovery for the period

January 2003 through December 2003. Please note that the final true-up under-recovery of $72,467,176 for the period January 2002 through December 2002 that was filed on April 1, 2003 was included in the midcourse correction that became effective in April 2003 and, therefore is not reflected in the $344,729,859 estimated/actual true-up amount to be carried forward to the 2004 fuel factors.

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

A. As shown on line 29 of Schedule E1, Page 3 of Appendix II, the total net true-up to be included in the 2004 factor is an under-recovery of $344,729,859. This amount divided by the projected retail sales of 100,913,607 MWh for January 2004 through December 2004 results in an increase of .3416¢ per kWh before applicable revenue taxes. The Generating Performance Incentive Factor (GPIF) Testimony of FPL Witness Frank Irizarry, filed on April 1, 2003, calculated a reward of $7,449,429 for the period ending December 2002 which is being applied to the January 2004 through December 2004 period. This $7,449,429 divided by the projected retail sales of 100,913,607 MWh during the projected period results in an increase of .0074¢ per kWh, as shown on line 33 of Schedule E1, Page 3 of Appendix II.

Q. **Has FPL included any additional costs in its factors for the**

period January 2004 through December 2004 as a result of the Hedging Resolution approved in Docket No. 011605-EI?

A. Yes. In Docket No. 011605-EI, the Commission approved the Hedging Resolution which allows for:

> "Each investor-owned electric utility may recover through the fuel and purchased power cost recovery clause prudently-incurred incremental operating and maintenance expenses incurred for the purpose of initiating and/or maintaining a new or expanded non-speculative financial and/or physical hedging program designed to mitigate fuel and purchased power price volatility for its retail customers each year until December 31, 2006, or the time of the utility's next rate proceeding, whichever comes first."

As stated in the testimony of FPL witness Gerard Yupp, FPL projects to incur $427,857 in incremental O&M expenses for FPL's expanded hedging program. Of this amount, $400,257 is for three (3) employees who are dedicated full time to FPL's expanded hedging program. Two of the employees were hired and have been working in 2003 and we expect the third employee to be hired in January 2004. These three employees have been (or will be) hired specifically for the expanded hedging program. Their salaries were not included in the MFR filing in Docket No. 001148-EI. In fact, their positions/job functions weren't even contemplated at the time of FPL's MFR filing.

Additionally, FPL's projected 2004 incremental hedging O&M expenses included $27,600 for computer license fees. This computer model is used for the expanded hedging program by providing a tool for volume forecasting on a continuing basis. The MFR filing contained $300,000 for projected computer license fees. FPL's total 2004 projections for these license fees is $327,600, therefore, FPL has included incremental license fees of $27,600 (the difference between the 2004 projection of $327,600 and the $300,000 included in the MFR filing) for recovery through the fuel clause.

Since the $427,857 in O&M expenses are for FPL's expanded hedging program and were not included in FPL's MFR filing in Docket No. 001148-EI, FPL has included this $427,857 in projected incremental hedging expenses in its Fuel Cost Recovery calculations for the period January 2004 through December 2004. This amount is shown on line 3b of Schedule E1, page 3 of Appendix II.

Q. **The following issue has been raised by Staff in its Preliminary List of Issues dated July 31, 2003: "What is the appropriate base level for operation and maintenance expenses for non-speculative financial and/or physical hedging programs to mitigate fuel and purchased power price volatility?" What is**

FPL's position regarding this issue?

A. There is no one general base level for O&M expenses that would be appropriate for the expanded hedging program. Each category of cost requested for recovery through the fuel clause has to be evaluated on a case by case, item by item basis to determine what portion, if any, of that category of cost was included in FPL's 2002 MFRs. The Commission's direction in Order No. PSC-02-1484-FOF-EI, in Docket No. 011605 is very clear. In the Order, in defining what constitutes "incremental" expenses for the purpose of allowing recovery of incremental operating and maintenance expenses associated with an expanded hedging program, the Commission approved the following procedure:

> "The base period for determining incremental expenses as described above is the year 2001 (using actual expenses), except for utilities with rates approved based on Minimum Filing Requirements (MFR) in rate reviews conducted since 2001, in which case the projected rate year is the base period (using projected expenses)...All base year and recovery year FERC sub-account operating and maintenance expense amounts associated with financial and physical hedging activities

> shall be included in the Fuel Clause Final True-up filing each April during the years 2003 through 2007, including the difference between the base year and recovery year expense amounts, then summed, yielding a total incremental hedging amount which may be compared for cost recovery review purposes to the requested cost recovery amount produced in the Projected Filing for the recovery year."

This procedure focuses on the specific accounts where the costs for which recovery is sought are recorded, not on the entire range of a utility's or business unit's operations. Thus, where FPL is entitled to recover incremental hedging costs through the fuel clause, the proper focus for evaluating whether the costs proposed for recovery are indeed incremental is on the level of *those particular costs* in the MFRs, in order to be sure that FPL would not be double recovering the costs (*i.e.*, recovering them in both base rates and through a cost recovery clause).

Q. Is FPL requesting recovery of costs for additional Plant Scherer railcars through the Fuel Cost Recovery Clause?

A. Yes. FPL is requesting the recovery of the return and depreciation of 137 new railcars for the Scherer Plant, as described in the testimony of FPL Witness Gerard Yupp, through the Fuel Cost Recovery Clause. The total cost of the railcars is $7 million. FPL has included

$1.4 million for the return and depreciation of these railcars in the calculation of its 2004 fuel cost recovery factors.

Q. What is the basis for requesting recovery of railcars through the Fuel Cost Recovery Clause?

A. The Commission in Docket No. 850001-EI-B, Order No. 14546 issued July 8, 1985, regarding the charges appropriately included in the calculation of fuel, stated:

> "As a result of the determination in this proceeding, prospectively, the following charges are properly considered in the computation of the average inventory price of fuel used in the development of fuel expense in the utilities fuel cost recovery clauses: ...4. Transportation costs to the utility system, including detention or demurrage".

Recovery of the return and depreciation associated with the additional Scherer railcars through the Fuel Cost Recovery Clause is appropriate, because they are transportation costs.

CAPACITY COST RECOVERY CLAUSE

Q. Please describe Page 3 of Appendix III.

A. Page 3 of Appendix III provides a summary of the requested capacity payments for the projected period of January 2004 through

December 2004. Total Recoverable Capacity Payments amount to $580,834,356 (line 16) and include payments of $177,228,528 to non-cogenerators (line1), Short-term Capacity Payments of $84,454,210 (line 2), payments of $350,288,484 to cogenerators (line 3), and $5,073,564 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 4a) $36,180,354 of Okeelanta/Osceola Settlement payments (line 5b), $13,673,611 in Incremental Power Plant Security Costs (line 6), and $6,259,386 for Transmission of Electricity by Others (line 7). This amount is offset $3,852,557 of Return Requirements on SJRPP Suspension Payments (line 4b), by Transmission Revenues from Capacity Sales of $4,235,810 (line 8), and $56,945,592 of jurisdictional capacity related payments included in base rates (line 12) less a net over-recovery of $28,725,148 (line 13). The net over-recovery of $28,725,148 includes the final over-recovery of $12,676,723 for the January 2002 through December 2002 period that was filed with the Commission on April 1, 2003, plus the estimated/actual over-recovery of $16,048,425 for the January 2003 through December 2003 period, which was filed with the Commission on August 12, 2003.

Q. Has FPL included a projection of its 2004 Incremental Power Plant Security Costs in calculating its Capacity Cost Recovery Factors?

A. Yes. FPL has included $13,613,611 on Appendix III, page 3, Line 6 for projected 2004 Incremental Power Plant Security Costs in the calculation of its Capacity Cost Recovery Factors.

Of the total $13,673,611 for 2004 incremental power plant security costs, $12,194,611 is for nuclear power plant security, which is discussed in the testimony of FPL Witness John Hartzog. In addition to the projection for nuclear power plant security costs, $1,479,000 of the total $13,673,611 is for fossil power plant security. This projection includes the costs of increased security measures for incremental fossil power plant security required by a recent Coast Guard rule and/or recommendations from the Department of Homeland Security authorities. These incremental fossil power plant security expenses include the cost of items such as gates, cameras, access card readers and security guards. FPL is in the process of complying with these requirements and will continue implementing these measures into 2004.

Q. The following issues have been raised by Staff in their Preliminary List of Issues dated July 31, 2003: "What is the appropriate period to establish a base line for incremental post-September 11, 2001, security expenses?" and "What is the appropriate base line for operational and maintenance expenses for post-September 11, 2001, security measures?" What are

FPL's positions on these issues?

A. When comparing incremental power plant security to base costs, the appropriate comparison is to FPL's 2002 MFRs filed in Docket No. 001148-EI. The essential purpose of the MFRs in Docket No. 001148-EI was to provide information on FPL's *base-rate* revenues, expenses and investment for the test year in question, making it the logical base period for comparing incremental expenses. Consistent with this emphasis on using 2002 MFRs to define what constitutes "incremental" expenses, the Commission has approved in Docket No. 011605 the following definition of base costs:

> "The base period for determining incremental expenses as described above is the year 2001 (using actual expenses), except for utilities with rates approved based on Minimum Filing Requirements (MFR) in rate reviews since 2001, *in which case the projected rate year is the base period (using projected expenses)*".

The 2002 MFRs filed in Docket No. 001148-EI do not include any of the incremental power plant security costs as a result of 9/11/01 or other Homeland Security responses that FPL has included for recovery through the capacity clause. On November 9, 2001, FPL filed adjustments to its 2002 MFRs to reflect the impact of the 9/11/01 events. However, the footnote on Attachment 1 of this filing stated that the adjustments "Reflects recovery of additional security costs through the fuel clause as filed 11/05/2001 in Docket 010001-EI." The "additional security costs" reflected in the fuel clause were the initial estimate of the costs of power plant security. Thus, from the outset the incremental power plant security costs as a result of 9/11/01 and other Homeland Security responses have been accounted for and recovered through the adjustment clauses and are not reflected in base rates.

Q. Please describe Page 4 of Appendix III.

A. Page 4 of Appendix III calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

Q. Please describe Page 5 of Appendix III.

A. Page 5 of Appendix III presents the calculation of the proposed Capacity Cost Recovery Clause (CCR) factors by rate class.

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

A. The Company is requesting that the new FCR and CCR factors become effective with customer bills for January 2004 through December 2004. 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 2004?

A. The base bill for 1,000 Residential kWh is $40.22, the fuel cost recovery charge from Schedule E1-E, Page 7 of Appendix II for a residential customer is $37.50, the Capacity Cost Recovery charge is $6.25, and the Environmental Cost Recovery charge is $0.13. These components of the Residential (1,000 kWh) Bill are presented in Schedule E10, Page 66 of Appendix II. The Conservation factor is not scheduled to be filed until September 26, 2003 and, therefore, is not included on Schedule E10.

Q. Does this conclude your testimony.

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLEMENTAL TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 030001-EI

NOVEMBER 3, 2003

Q. Please state your name and business address.

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

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

A. I am employed by Florida Power & Light Company (FPL) as the Manager of Regulatory Issues in the Regulatory Affairs Department.

Q. Have you previously filed testimony in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the portion of Staff's position on Issue 30 that states: "Once the base year costs are determined, the costs would be grossed up (or down) for the growth (or decline) in kWh sold from the base year to the recovery year."

Q. Focusing on the first part of Staff's proposal that states "Once the base year costs are determine," do you agree that post-9/11 incremental power

plant security expenses necessarily need to be compared to a "baseline" to determine the appropriate amount to be recorded through the Capacity Cost Recovery (CCR)?

A. No, while a "baseline" adjustment might be appropriate in evaluating whether certain types of increased costs are eligible for recovery through the CCR clause, Staff's "baseline" concept is simply not relevant to the way that FPL accumulates and tracks its incremental power plant security costs. FPL did not include any post-9/11 incremental power plant security expenses in its 2002 MFRs; thus, the base year amount of such expenses is zero. FPL has established separate accounts to record and track its incremental power plant security expenses. FPL only records expenses to those separate accounts if the expenses result from specific, post-9/11 security requirements. Therefore, the full amounts recorded in those accounts are incremental power plant security expenses. There is no need to compare such expenses to a "base line" in order to determine the appropriate amount to be recovered through the CCR Factor.

FPL's approach to accumulating and tracking post-9/11 incremental power plant security costs is analogous to what is done with respect to project costs that are recovered through the Environmental Cost Recovery Clause (ECRC). For example, Order No. PSC-94-0044-FOF-EI, dated 1/12/94, states:

"Upon petition, we shall allow the recovery of costs associated with an environmental compliance activity through the environmental cost recovery factor if .the activity is legally required to comply with a governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based."

Typically, there is no "baseline" for the costs of an ECRC project, because the project activities were not needed until the environmental requirement in question became effective. Thus, rather than trying to apply a baseline to evaluate whether the costs of a new ECRC project are recoverable, the project costs are tracked separately from other environmental activities. The focus of the ECRC review is then on whether or not these separately tracked costs are indeed required to comply with the relevant environmental requirement. This is the same concept that FPL is using for its post-9/11 incremental power plant security costs in this docket.

Q. If a baseline were to be established for FPL, would Staff's proposal to make an adjustment to reflect revenues in the calculation of incremental costs by grossing up the expense in the base year by the growth rate in energy sold be appropriate?

A. No. If a baseline other than "zero" were to be established for FPL, Staff's proposal to adjust that baseline annually for increased kWh sales would be inappropriate. Such an adjustment would improperly interject the issue of base-rate revenue growth into the adjustment clause proceeding. And it would do so by unfairly looking at only one side of the revenue-expense relationship.

A sales-growth adjustment would be especially inappropriate for FPL because of the current Settlement and Stipulation that was approved by the Commission in Docket No. 001148-EI. That settlement reduced FPL's base rates by $250 million per year from the level anticipated by the 2002 MFRs filed in that docket, yet Staff suggests no downward adjustment to the initial baseline to reflect that revenue reduction. Moreover, the settlement contains a revenue-sharing mechanism that provides additional refunds to FPL's customers if base-rate revenues exceed prescribed thresholds. The settlement states that the revenue-sharing mechanism "will be the appropriate and exclusive mechanism to address earnings levels." Staff's proposal to increase baseline costs (and hence decrease recoverable security expenses) proportionately to increased kWh sales amounts to an indirect adjustment to earnings, which would be inconsistent with this provision of the settlement.

The revenue-sharing mechanism represented a compromise on revenue sharing that was acceptable to all of the settlement signatories. They agreed that this compromise would apply for calendar years 2003, 2004 and 2005. The compromise did not contemplate making additional adjustments such as the one that Staff suggests, which would have the effect of changing the balance of revenue sharing away from what the parties had agreed to accept.

Q. Does that conclude your rebuttal testimony?

A. Yes it does.

BY MR. BUTLER:

Q Please summarize your testimony.

A Okay. The purpose of my testimony is to present for Commission review and approval the fuel cost-recovery factors and the capacity cost-recovery factors for the company's rate schedules for the period January 2004 through December 2004. Additionally, my direct testimony addresses several issues related to setting a baseline for incremental post-9/11 power plant security costs and incremental hedging expenses that were raised by staff.

Regarding incremental hedging O&M expenses, FPL's expanded hedging program has required use of consultants, new reporting systems, and three additional employees that were not included in FPL's MFR filing. There is no one general base level of O&M expenses that would be appropriate for the expanded hedging program. Each category of costs requested for recovery through the fuel clause has to be evaluated on a case-by-case, item-by-item basis to determine what portion, if any, of that category of cost was included in FPL's 2002 MFRs.

Regarding a baseline for post-9/11 incremental power plant expenses, FPL did not include any post-9/11 incremental power plant security expenses in its 2002 MFRs. Therefore, the base year amount of such expense is zero. FPL has established separate accounts to record and track its incremental power plant security expenses, and FPL only records expenses in those separate accounts if the expenses result from specific post-9/11 security requirements. Therefore, the full amounts recorded in those accounts are incremental power plant security expenses.

On November 3rd, I filed supplemental testimony that addresses the portion of staff's position on Issue 30 that states, "Once the base year costs are determined, the costs will be grossed up or down for a growth or decline in kWh sold from the base year to the recovery year." FPL believes that this adjustment is inappropriate because it is inconsistent with the current rate settlement agreement. The settlement contains a revenue-sharing mechanism that provides additional refunds to customers if base revenues exceed prescribed thresholds. The settlement states that the revenue sharing mechanism, quote, will be the appropriate and exclusive mechanism to address earning levels, unquote. Staff's proposal to increase base line costs and, hence, decrease recoverable clause expenses proportionately to increase kWh sales amounts to an indirect adjustment to earnings which will be inconsistent with the provisions of the settlement.

Furthermore, the revenue sharing mechanism represented a compromise on revenue sharing that was acceptable to all of the settlement signatories. They agreed that this compromise would apply for calendar years 2003, 2004, and 2005. The compromise did not contemplate making additional adjustments such as the one that staff suggests, which would have the effect of changing the balance of revenue sharing away from what the parties had agreed to accept.

This concludes my summary.

MR. BUTLER: I tender Ms. Dubin for cross examination.

CHAIRMAN JABER: Thank you. Mr. Vandiver, have you agreed upon an order of questioning?

MR. VANDIVER: Yes. We have no questions.

MS. KAUFMAN: I have no questions, Chairman.

CHAIRMAN JABER: Mr. Twomey, I'm assuming you have no questions?

MR. TWOMEY: (Indicating no.)

CHAIRMAN JABER: And I will assume that, by the way, if you're not at a microphone, okay? All right.

Staff.

MR. KEATING: Staff has no questions.

CHAIRMAN JABER: Well, who had questions of Ms. Dubin?

COMMISSIONER DEASON: I have a question.

CHAIRMAN JABER: Well, Commissioner, go right ahead.

MR. BUTLER: We knew that.

COMMISSIONER DEASON: I'm trying to understand the gross-up issue on the security costs, the post-9/11 security costs. As I understand your testimony, there were no such costs included in your MFR filings, you have a separate accounting system, and therefore whatever accounts, whatever amounts are in those accounts, by definition they are incremental. Did I understand that testimony correct?

THE WITNESS: Yes, Commissioner.

COMMISSIONER DEASON: Okay. So does the gross-up issue effect you, does it effect you in terms of dollars or just in terms of policy?

THE WITNESS: Just in terms of policy, Commissioner. The baseline or the amount that we have included in the MFRs for the power plant security cost is zero.

COMMISSIONER DEASON: If you gross-up zero, it is zero?

MS. DUBIN: Exactly.

CHAIRMAN JABER: Mr. Butler, you have no rebuttal. Redirect?

MR. BUTLER: I have no redirect.

CHAIRMAN JABER: Okay. Ms. Dubin, thank you for your testimony. And without objection, Composite Exhibit 13 is admitted into the record.

(Exhibit 13 admitted into the record.)

MS. DUBIN: Thank you.

CHAIRMAN JABER: According to my list, the next witness is Mr. Portuondo.

MR. McGEE: Madam Chairman, the parties have had some ongoing discussion about Progress Energy's specific Issue 13E, the waterborne transportation issue, and we would ask that that portion of Mr. Portuondo's testimony be deferred now and taken out of order after we have had a chance to conclude our discussions which, in effect, would mean that Mr. Portuondo would be subject to cross-examination on Issues 30 and 31A. If I have missed any other issues that are not included within 30 and 31A --

CHAIRMAN JABER: Let me see if I understand. You want an opportunity to talk further about 13E, which may make his testimony not necessary for 13E?

MR. McGEE: That's correct. That's the portion of his September 12th testimony from Pages 15 through 24.

CHAIRMAN JABER: But if you don't have a stipulation, then we would have to bring him back up on the stand to take up 13E?

MR. McGEE: Yes, ma'am.

CHAIRMAN JABER: How about for the sake of efficiency we skip him?

MR. McGEE: That's acceptable to us.

CHAIRMAN JABER: Good.

TECO, is it Mr. Whale?

MR. BEASLEY: That's correct. Call Mr. Whale.

CHAIRMAN JABER: Mr. Beasley, I was just asking Commissioner Baez if you agreed to taking up direct and rebuttal at the same time.

Parties, have you reached agreement on whether direct and rebuttal may be taken up at the same time?

MR. BEASLEY: We haven't. And we would like to keep the order of witnesses as they are stated.

CHAIRMAN JABER: All right. So this is just for direct, then?

MR. BEASLEY: That's correct.

WILLIAM T. WHALE

was called as a witness on behalf of Tampa Electric Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Whale, would you please state your name, your business address, and your position with Tampa Electric Company?

A Yes. My name is William T. Whale. My business address is 702 North Franklin Street, Tampa, Florida 33602. I'm employed by Tampa Electric as Vice-president of Energy Supply Operations.

Q Mr. Whale, did you prepare and cause to be submitted in this proceeding a document entitled, "Projection Testimony of William T. Whale," that was filed on September 12th, 2003?

A Yes, I did.

Q Do you have any corrections or changes to make to that testimony?

A No, I do not.

Q If I were to ask you the questions contained in that testimony, would your answers be the same?

A Yes, they would.

MR. BEASLEY: Madam Chairman, I would ask that Mr. Whale's testimony be inserted into the record.

CHAIRMAN JABER: The prefiled direct testimony of William T. Whale shall be inserted into the record as though read.

BY MR. BEASLEY:

Q Mr. Whale, did you also accompany that testimony with an exhibit designated Exhibit WTW-1?

A Yes, I did.

Q Was that prepared under your direction and supervision?

A Yes, it was.

MR. BEASLEY: I would ask that Mr. Whale's Exhibit WTW-1 be marked for identification.

CHAIRMAN JABER: WTW-1 shall be marked as Exhibit Number 14.

MR. BEASLEY: Thank you.

(Exhibit 14 marked for identification.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM T. WHALE

Q. Please state your name, address, occupation and employer.

A. My name is William T. Whale. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Vice President, Energy Supply - Operations.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree from the United States Merchant Marine Academy in 1978, and a Master's of Business Administration from Florida Institute of Technology in 1986. I began my career with Tampa Electric in 1979 as a Boiler Engineer in the Production Department. From 1979 through 1991 I held various engineering and management positions within the Production Department. In 1991 I transferred to TECO Power Services and from 1991 through 1996 I held various position of increasing responsibility and oversight of power plant operations.

In 1996 I transferred to TECO Transport and Trade and from 1996 through 2000 I held various management positions. In March 2000 I transferred back to Tampa Electric and became Vice President, Energy Supply. I am responsible for oversight of the operations and maintenance of Tampa Electric's power plants.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the obligations that Tampa Electric has under the Consent Decree ("CD") entered into with the United States Environmental Protection Agency and Department of Justice and the Consent Final Judgment ("CFJ") entered into with the Florida Department of Environmental Protection as they relate to Gannon Station. I will also discuss the various factors that influenced Tampa Electric's shutdown schedule of the Gannon Units 1 through 4.

Q. Have you prepared an exhibit to support your testimony?

A. Yes. Exhibit ____ (WTW-1), consisting of one document, was prepared under my direction and supervision. Document No. 1 is titled "Gannon Station Performance and Reliability."

Q. Please describe Tampa Electric's obligations under the CFJ and the CD as they relate to Gannon Station.

A. Under the CFJ, signed December 6, 1999, and the CD, signed February 29, 2000, Tampa Electric must cease operating its coal-fired generation at Gannon Station by December 31, 2004. Specifically, the CD requires Tampa Electric to repower coal fired generating capacity at Gannon of no less than 200 megawatts ("MW") by May 1, 2003. As a result, Gannon Units 5 and 6 are being repowered from coal to natural gas fired Bayside Units 1 and 2, respectively. The shutdown schedules for Gannon Units 5 and 6 are driven by the in-service dates of Bayside Units 1 and 2.

Q. Given the obligation under the CD and CFJ, what is Tampa Electric's conversion schedule?

A. To achieve the required May 1, 2003 in-service date for Bayside Unit 1, Gannon Unit 5 was shut down on January 30, 2003 to convert its steam turbine generator to the Bayside Unit 1 combined cycle configuration. Due to the planned January 15, 2004 in-service date for Bayside Unit 2, the shutdown date for Gannon Unit 6 will occur around September 30, 2003. Gannon Units 3 and 4 will be shut down around October 15, 2003 so that Bayside Unit 2 can utilize the transmission facilities currently used for the operation of Gannon Unit 4. The existing transmission facilities cannot accommodate the operation of both Bayside Unit 2 and Gannon Unit 4; therefore, it will be necessary for Gannon Unit 4 to cease operations to allow for the tie-in and testing of Bayside Unit 2 prior to its commercial operation.

Q. Please provide a description of the Gannon units.

A. Gannon Station has been operational for over 46 years. Gannon Unit 1 was commissioned in 1957 and, prior to being shut down and placed on long-term reserve standby, had a net capacity rating of 94 MW. Gannon Unit 2 was commissioned in 1958 and, prior to being shut down and placed on long-term reserve standby, had a net capacity rating of 100 MW. Gannon Unit 3 was commissioned in 1960 and has a net capacity rating of 155 MW. Gannon Unit 4 was commissioned in 1963 and has a net capacity rating of 100 MW. Each of the Gannon units has one boiler supplying steam to one steam turbine generator.

Q. Please provide a description of the Bayside units.

A. Bayside Unit 1 consist of three General Electric ("GE")

7FA gas turbines and three heat recovery steam generators ("HRSGs") supplying steam to one steam turbine generator; it reused the Gannon Unit 5 steam turbine generator and associated equipment. It went into commercial operation April 24 of this year. Bayside Unit 2 will consist of four GE 7FA gas turbines and four HRSGs that supply steam to one steam turbine generator unit; it will reuse the Gannon Unit 6 steam turbine generator and associated equipment. The unit is expected to be in service January 15, 2004. Bayside Unit 1 has a net capacity of 690 MW and 779 MW in the summer and winter, respectively. Bayside Unit 2 will have a net capacity of 908 MW and 1,022 MW in the summer and winter, respectively.

Q. Please describe the process of converting coal-fired Gannon Units 5 and 6 to natural gas-fired Bayside Units.

A. The process to bring each Bayside unit on line is similar in scope. Construction of the Bayside units has taken place while the existing Gannon units have continued to operate. This has significantly increased the complexity of bringing the units on line.

Bayside construction can only be completed up to a certain point with the respective Gannon Units 5 and 6 operating.

At that point, the respective Gannon unit must be removed from service to allow the final construction tie-ins to take place. When the tie-in is complete, the start-up or commissioning phase begins. Systems are checked out; construction is verified; design is validated; and control systems are tuned. This is a dynamic process because the exact issues to be addressed are not known in advance. Scheduling the activities is primarily based upon experience with similar units.

The gas turbines are fired individually to verify turbine integrity. The combustion system of each turbine is tuned to ensure emission performance. After all turbines have been tested and tuned, the steam section of the unit is put into service. This includes verification of control logic, construction correctness, steam piping hanger design, plant water balance and piping system expansion. Also, in this step the unit condenser, condensate and boiler feedwater systems are checked out and commissioned.

The next step is to admit steam to the steam turbine. This step verifies that modifications to the steam turbine work as planned.

Once the unit is producing electricity from both the gas turbines and steam turbine in combined cycle mode, final tuning and testing is done. The final step is to run the unit performance and emission test to verify compliance. Upon completion of the aforementioned tests, the unit is released to operations and declared in service.

Q. How has the company evaluated the schedule of shutting down the coal fired Gannon Units?

A. Although the CFJ and CD require that all coal fired operations cease by December 31, 2004, the company never anticipated or planned for the shutdown of the units to occur exactly on December 31, 2004. Since the CD and CFJ were signed, the company has continued to evaluate various conditions in determining when the Gannon coal fired units would be shut down. These considerations include, but are not limited to, the engineering and construction of the repowered Gannon Units 5 and 6 to Bayside Units 1 and 2, respectively, the reliability and safety of Gannon Units 1 through 4, necessary maintenance costs and planned outage time for acceptable levels of unit availability, employee redeployment and retraining schedules, reserve margin requirements, outage schedules (statewide and system-wide) and transmission constraints. Over time, the status of these conditions has been and continues to be monitored and updated.

In late January and early February of this year, the company was in a position to further refine the dates for ceasing operation of Gannon Units 1 through 4. At that time, the company determined that the shutdown of Gannon Units 1 and 2 should occur around March 15, 2003 and the shutdown of Gannon Units 3 and 4 should occur in September 2003 to coincide with the Bayside Unit 2 tie-in activities. Due to necessary modifications to the company's outage schedule and unforeseen system and statewide operational issues, the company continued operating Gannon Units 1 and 2 beyond the previously scheduled mid-March 2003 shutdown. Once Bayside Unit 1 produced energy reliably, generating units returned from outages and system conditions warranted, Tampa Electric finalized the dates to shut down Gannon Units 1 and 2.

Q. What have been the primary parameters affecting the decision on when to shut down the Gannon units?

A. Since signing the CFJ and CD, Tampa Electric has worked with an engineering, construction, and shutdown schedule that has consisted of legal and operational parameters. The legal parameters have been primarily driven by obligations under the CFJ and CD. The primary operational parameters have been the engineering, construction, and testing schedules for Bayside Units 1 and 2, the reliability and availability of the Gannon Station units, the safety concerns for operating personnel and an optimal schedule for reassigning and retraining employees currently working at Gannon Station for other positions within the company. The company has always considered this process to be fluid, recognizing there would be matters that would arise that would require flexibility.

Q. What considerations ultimately influenced Tampa Electric's selection of appropriate shutdown dates for Gannon Units 1 through 4?

A. As I previously stated, the company never anticipated or planned for the shutdown of Gannon Units 1 through 4 to occur exactly on December 31, 2004. In fact, Tampa Electric made a determination that it would attempt to keep the units running as long as reliably possible without incurring significant expenditures given the age of the units, the short remaining life and the associated outage time necessary for any planned maintenance work.

The maintenance process became more deliberate and defined as the construction of Bayside Units 1 and 2 advanced. Forced outages became and continue to be more frequent due to equipment issues such as weakened boiler cyclone and furnace tubes. The weakened tubes have caused external tube failures and gas leaks which have resulted in decreased reliability and availability as well as an increased potential for safety incidents. In light of Tampa Electric's obligations to cease coal-fired generation at the station and the age of the units, the company determined that the most prudent approach to maintenance was to use a "patch and go" approach which required limited investment with minimal planned outage time. The performance decline has impacted the company's ability to plan and execute optimal operational strategies that serve customers in the most cost-effective manner.

By the summer of 2002, Tampa Electric began to perform detailed evaluations, considering numerous options, for possible shutdown dates for Gannon Units 1 through 4 given the successful implementation of the Bayside construction schedule, Gannon units' declining reliability, the potential for safety incidents and decreased output of the units. The company ran multiple scenarios to evaluate ratepayer impacts (including fuel and purchased power costs), operation and maintenance ("O&M") impacts, and wholesale sales opportunities for off-system sales. Although the scenarios provided estimated dollar impacts given various shutdown dates, the company remained cognizant of the fact that the exact shutdown dates would, to a certain extent, remain flexible.

By late 2002, it became apparent that the units needed to be shut down in 2003. This realization was driven primarily by four factors: the declining availability and reliability of the units; the significant expenditures that would need to be incurred in an effort to keep the units running reliably; the potential for safety incidents; and, the short window of time until the units would be required to shut down under the CFJ and CD, regardless of how much the company might invest in an effort to keep them operating.

A formalized plan was developed that took into account all of these considerations. On February 6, 2003, Tampa Electric notified its employees that it planned to shut down Gannon Units 1 and 2 on March 15, 2003 and Gannon Units 3 and 4 in September 2003. On February 7, 2003, the company notified the Florida Department of Environmental Protection, the Environmental Protection Agency, and the Department of Justice of its refined plans. On February

24, 2003 the company filed a petition for a fuel mid-course correction, which included the shutdown of the Gannon Units 1 through 4 as part of its system operations plan for 2003.

Q. What are the safety concerns that have prompted early closure of the Gannon units?

A. The majority of the operational and equipment concerns, such as structural steel fatigue, boiler cyclone and furnace tube deterioration, gas duct and boiler casing deterioration that impact the units' reliability and availability are directly related to the equipment age and hours of service. As operational restrictions and equipment failures have increased, the company has become more concerned with potential safety incidents. For example, all four units have experienced increased boiler cyclone and furnace tube failures. Increased occurrences of boiler furnace tube separation have led to external leaks, which have increased the potential for harmful gases such as SO_2, NO_x and carbon monoxide to be released into work areas. Two of the units have experienced external tube leaks, thereby increasing the potential for exposure to steam leaks. In addition, boiler casing and duct damage have the potential to expose asbestos insulation. The company has taken steps to modify operating parameters in an attempt to reduce the potential for safety incidents while keeping the equipment operating.

Q. On a unit-by-unit basis, what are the relevant reliability concerns that have prompted the decision to shut down Gannon Units 1 through 4?

A. As I have stated, the age of the equipment and hours of operation are key factors impacting the units' performance and reliability. Even though the company has taken steps to modify operating parameters, boiler cyclone and furnace tube failures pose significant reliability concerns for the company. Over the last calendar year, boiler cyclone and furnace tube failures have increased 300 percent at Gannon Station. These failures along with equipment fatigue and structural damage have resulted in significant lost generation due to unplanned outages and have resulted in the company modifying the operating parameters for each unit.

Gannon Unit 1 was commissioned with a boiler design header pressure of 1,750 pounds per square inch ("psi"). Prior to being shut down, this unit operated at 1,200 psi to reduce the likelihood of tube failures due to material degradation and thinning, which reduces the boiler tubes' ability to withstand pressure ("tube metal safety factor"). Tube failures increased 1,025 percent from 2001 to 2002.

Gannon Unit 2 was commissioned with a boiler design header pressure of 1,750 psi. Prior to being shut down, this unit only operated at 1,000 psi to increase tube metal safety factor. Tube failures increased by 832 percent from 2000 to 2002. Another reliability concern was the deteriorated condition of the last stage turbine blades, which resulted in the tips of blades breaking off in service. The third point feedwater heater had over 30 percent of its tubes plugged and the tube leaks presented operational problems. Additionally, due to age, the control wiring insulation at the turbine front standard was in poor condition and continued to lead to electrical grounds and problems with resetting the turbine prior to startup.

Gannon Unit 3 was commissioned with a boiler design header pressure of 2,175 psi. Currently the unit operates at 1,800 psi to increase tube metal safety factor. Tube failures increased 1,450 percent from 2000 to 2002 and boiler casing leaks have resulted in reduced generating load because of carbon monoxide gas leaks in work areas over the last three years. Also, the third point feedwater heater has holes in the shell due to deterioration and internal erosion.

Gannon Unit 4 was commissioned with a boiler design header pressure of 2,250 psi. Currently the unit operates at 1,000 psi of pressure to increase tube metal safety factor. Tube failures have increased 1,188 percent over the last three years. The water walls and nose arch have permanent internal hydrogen damage. Boiler casing leaks have resulted in reduced generating load because of carbon monoxide gas leaks in work areas and the third and fourth point feedwater heaters are continually experiencing tube failures which increase the risk of water induction damage to the steam turbine. The fifth point heater has holes through the shell that have resulted in water leaking into the condenser. In addition, the last stage turbine blades are in poor condition due to long-term erosion from moisture in the steam.

Document No. 1 of Exhibit ____ (WTW-1) are graphs which illustrate the aforementioned increasing number of tube repairs, gas leak outages and structural work orders due to material fatigue and erosion by unit.

Q. What are the estimated necessary expenditures to keep Gannon Units 1 through 4 operating through 2004?

A. Given the current condition of these units, Tampa Electric estimates that it would need to incur additional O&M expense of approximately $57 million to try to keep Gannon Units 1 through 4 operating somewhat reliably beyond the actual and currently planned shutdown dates and through 2004. Even this significant level of investment is not a guarantee that Gannon Units 1 through 4 would operate at planned availability levels due to the age of the units and the performance declines that have been experienced, as previously described.

Q. Are there additional costs that would need to be incurred to keep the units running through 2004?

A. Yes. To the extent that the performance of the units continues to decline despite investment in repairs and maintenance, there would be additional costs incurred to replace power during forced unplanned outages.

Q. Is there any flexibility in the planned shutdown schedule for the units?

A. While the planned dates are relatively precise, the company continues to recognize the need for the exact shutdown dates to remain flexible to the extent that is possible. For example, if there is a significant failure of a unit prior to the planned shutdown of that unit, the company will evaluate the failure and determine whether it is prudent to make the necessary repairs. Similarly, if the units are running and there are system or statewide operational concerns that should be considered, the company will reevaluate its decisions and may refine the dates if appropriate.

Q. What action was taken or will be taken regarding the employees at the various Gannon Station units?

A. Employees at Gannon Station are in International Brotherhood of Electrical Workers ("IBEW") covered operating positions. The Gannon/Bayside employee transition plan involves employees located at Gannon Station, Big Bend Station and TECO Stevedoring because IBEW contractual agreements govern seniority and position reclassification. Therefore, the company has entered into an agreement with the IBEW to facilitate the

Gannon/Bayside staffing transition of covered employees. Based on the required number of positions needed after the transition, early retirement offers, voluntary separation offers and re-deployment of employees into positions within the company, there are no plans for lay-offs.

Q. Does this conclude your testimony?

A. Yes it does.

BY MR. BEASLEY:

Q Mr. Whale, would you please summarize your direct testimony?

A Yes, I will.

Good morning, Commissioners. My name is Bill Whale, and I'm Vice-president of Energy Supply Operations at Tampa Electric. My direct testimony explains Tampa Electric's decision to shut down the Gannon Units in 2003. My testimony provides a description of Tampa Electric's decision-making process, and describes the factors that form the basis for the company's decision. Tampa Electric is obligated by the consent decree with the EPA and a consent final judgment with the Florida DEP to cease operating its coal-fired generation and repower its units at Gannon Station.

Specifically, the consent decree requires Tampa Electric to repower coal-fired generating capacity at Gannon Station of no less than 200-megawatts by May 1st, 2003, as the first phase of the repowering. To accomplish this and to meet Tampa Electric's current and future generating capacity needs, the company is repowering Gannon Station to clean-burning natural gas-fired Bayside Station.

Tampa Electric determined that Gannon Units 5 and 6 would be repowered and has maintained a flexible schedule for shutting down Gannon Units 1 through 4. Gannon Unit 5's steam turbine generator and its associated auxilliary equipment, together with three new combustion turbines and three new heat recovery steam generators became Bayside Unit 1 and began commercial operations on April 24th, 2003.

The Unit Number 6 steam turbine generator and its associated auxilliary equipment, together with four new combustion turbines and four new heat recovery steam generators will become Bayside Unit 2 and will begin commercial operations on January 15th, 2004.

Additionally, Bayside Unit 2 will also utilize equipment from Gannon Unit 4. Therefore, the shutdown dates for Gannon Units 4, 5, and 6 were driven by the repowering construction activities. Bayside Units 1 and 2 will have a net capacity of 1,598 megawatts in the summer, and 1,801 megawatts in the winter. This provides a net 579-megawatt capacity increase in the summer, and a net 758-megawatt capacity increase in the winter when compared to Gannon Station.

Units 1 through 3, the other three units at Gannon Station, had a combined total capacity of 349-megawatts prior to shutdown. Tampa Electric made the determination, given the age of the units and the fact that they must be shutdown, the company would attempt to keep the units running as long as reliably and safely possible without making large investments in them. It's important to keep in mind that these units have been operating for a long time and that they could no longer burn coal due to the consent decree and consent final judgment.

Gannon Unit 1 was commissioned in 1957, Gannon Unit 2 was commissioned in 1958, Gannon Unit 3 was commissioned in 1960, and Gannon Unit 4 was commissioned in 1963. During 2002, forced outages at Gannon Station became and continue to be more frequent due to equipment issues, such as boiler tube failures, feed water tube failures, boiler casing leaks, structural steel deterioration, and steam turbine problems.

To address the operational and reliability issues that Tampa Electric experienced at Gannon Station, the company adopted a patch and go maintenance strategy. The benefits of this strategy were two-fold. The first benefit was greater availability of the units because they would be not taken off-line for extended planned outages that would have been required for substantial repairs and component replacements.

The second benefit was that Tampa Electric was able to invest in other units that would be able to continue operating in the future. The needed improvements to the Gannon units, if made, would have had expected service lives of ten years or more, and therefore those investments that would have been made would have been lost with the required near-term shutdown of the Gannon units.

In the second half of 2002, the company began evaluating time frames to shut down the units. There were several primary factors that when viewed collectively required that the units should be shut down in 2003. The declining availability and reliability of the units, the significant expenditures that would be required to keep the units running reliably, the potential for safety incidents, the short window of time until the units would be required to be shut down by the consent decree and the consent final judgment, and a need for a smooth transition with our work force. Tampa Electric evaluated a number of scenarios to determine the best shutdown schedule that took into account safety, reliability, other operational factors, and the estimated impact to its customers.

From an employee standpoint, the Gannon Station employees are covered by the International Brotherhood of Electrical Workers. Due to the number of positions required at Bayside after the transition, Tampa Electric entered into an agreement with the union to facilitate the Gannon/Bayside staff transition. The transition plan included early retirement packages, voluntary separation offers, displacing contractors, using overtime for existing employees, and movement of employees to different departments or stations within Tampa Electric. These actions resulted in there being no need for layoffs to accomplish the employee transition.

Although the EPA consent decree and the DEP consent final judgment required Gannon Station to cease burning coal by December 31st, 2004, the company never intended that Gannon 1 through 4 would operate right up until midnight of that night. In fact, the consent decree and consent final judgment used the language on or before December 31st, 2004. Tampa Electric's actions have been diligent and prudent as the company carefully considered all the factors that I have described, and has finalized the Gannon-to-Bayside transition plan.

That concludes my summary.

MR. BEASLEY: We tender Mr. Whale for questions.

CHAIRMAN JABER: Thank you, Mr. Beasley. Mr. Vandiver.

CROSS EXAMINATION

BY MR. VANDIVER:

Q Good afternoon, Mr. Whale.

A Good afternoon.

Q Mr. Whale, on Pages 3 and 8 of your direct testimony you discuss the shutdown dates for Gannon Station, I believe, sir?

A Was that Page 3?

Q Yes, sir. Page 3 and Page 8. And I just want to pin down the exact dates that Gannon 1, and 2, and 3, and 4 were shut down, sir. If we could start with 1 and 2?

A That would be fine. Gannon 1 and 2 were shut down on April 7th, Gannon 2 was shut down on April 9th, Gannon 4 was shut down on the 12th of October, Gannon 3 was shut down on the 24th of October.

Q All right, sir. And then on Page 8, starting on Line 22 you described your agreements with EPA and DEP that required you to replace 200 megawatts of coal-powered generation at Gannon by May 1st, 2003?

A That's correct.

Q And that was the sole requirement for gas powered generation under the consent decree, is that correct?

A There was a requirement of December 31st of 2004 to have 500 megawatts repowered.

Q Yes, sir. And did you comply with that requirement by converting Gannon 5 to gas in early 2003?

A Yes.

Q And the other major requirement under the consent decree was to cease coal operations at Gannon Station no later than December 31st, 2004?

A On or before, yes.

Q Okay. And on Page 9, starting at Line 18, you state that it was your goal to keep Gannon Units 1 through 4 running as long as reliably possible, is that correct?

A That's correct. Without incurring significant expenditures, correct.

Q I want to hand you a document now. This was provided to us in our request for production of documents. This is Bates stamped 2644 and 2645. I'm going to give it to the Commissioners and the parties and let you take a look at it, sir. Who is Chuck Hemrich?

A Chuck Hemrich was the engineering manager at Gannon

Station.

Q And who is Karen Sheffield?

A Karen Sheffield was the plant manager.

Q This is dated August 10th, 2002?

A The date of this is August 7th, 2002.

Q Thank you. And did you receive a copy of this memo?

A It's addressed to me, I don't remember the memo.

Q Okay. And this memo is an evaluation of the budget needs for Tampa Electric regarding Gannon Station maintenance for 2003/2004?

A It's listed in the discussion of 2003/2004 O&M.

Q Okay. And I direct your attention to the first two lines of the second page. And does that outline the maintenance and budget needs to prepare Gannon Station for an 18-month run with minimal cost clean-up in 2004 on each unit?

A It states the cost for an 18-month run clean-up, yes, it does.

Q All right. And so I know that you were looking at a lot of scenarios at this point in time, were you not?

A That is correct.

Q And so this particular scenario was to run Gannon 1 through 4 well into 2004, was it not?

A For 18 months at the time. Yes, that would be -- from August 7th there that would be into 2004.

Q Okay. I would like to go back to your testimony now, but, again, the reference here, I just want to direct your attention now, the outage work here, the outage work here needed for repair of cyclones, duct work, screen, what kind of cost are we looking at there, sir?

A According to this document it says the cost of the 2003 outage is $4 million.

Q All right, sir.

A According to this document.

Q Thank you. And that was an August 2002 estimate?

A That's correct.

Q I would like to go back to your testimony now, sir. And I would direct your attention to Page 10, Lines 9 through 13. And you state you decided the best way to achieve your goal was patch and go, sir?

A That's correct.

Q Can you please describe the patch and go strategy for maintenance?

A The patch and go strategy for maintenance was if a unit came down, we would do the repairs necessarily to get the unit turned around as soon as possible. It was not a strategy of going in and keeping the unit down for long planned outages and do major change-outs. We found that that strategy was going to provide a higher availability of the unit on a short-term basis versus a longer-term basis. So we adopted the patch and go strategy for that time period.

Q And the patch and go strategy, as I understand it, would necessarily -- or would it involve deferring planned outages?

A The patch and go strategy would help as far as avoiding long planned outages. It was work that could be done during forced outages when the units came off. Due to the frequency of those forced outages, we would do that work at that time and avoid those major planned outages.

Q Okay. And on Pages 11 through 15 you state all of the reliability, availability, and safety factors that influenced your decision to shut down Gannon Station earlier than originally planned, is that correct?

A Correct.

Q And then on page -- specifically on Page 13 you speak of reliability, is that correct?

A Reliability, yes.

Q Okay. And there are several measurements that you used to measure reliability and availability, is that correct?

A We primarily use EAF, which is equivalent availability factor of the unit. That is the primary one.

Q All right. And on-peak availability is one of those measurements, is it not?

A On-peak availability is really a measure of how reliable the units are for a particular peak when the native load of Tampa Electric exceeds 2,900. It is a new measure that we have used.

MR. VANDIVER: Okay. I'm going to hand you another document, sir. Now, I need to preface this with an explanation to the Commission. This identical chart is shown in Mr. Zaetz's testimony at Page 9 of 45. And that is a confidential document. The document that I am handing out is not confidential. This was given to us in our production of documents by Tampa Electric Company. This is Bates stamped 2479, and, Mr. Beasley, this is a white page. It is identical to what is in Mr. Zaetz's testimony.

And I am going to have Mr. Poucher give you a copy of Mr. Zaetz's testimony, Mr. Whale, and let you compare these two and just assure yourself that they are the same piece of paper.

But, again, Commissioners, this is not a confidential document.

And, Mr. Beasley, this was in the white pieces of paper that you produced to me, and it is not confidential. So just for walking around and talking about it here, I thought it would be easier for our discussion to refer to a nonconfidential piece of paper.

MR. BEASLEY: Sure, I will take your word for it. We will be glad to do that.

MR. VANDIVER: Okay. Thank you.

MR. BEASLEY: We produced probably about 16,000 pages, I assume this was in that somewhere.

MR. VANDIVER: In the rush of the thing, I thought it would be a lot easier for hearing purposes to talk about something that was nonconfidential. We have several of these that we are going to walk through, and I just thought it would be easier for the Commission to look at something that was not confidential instead of having to refer to X and all of that.

CHAIRMAN JABER: Thank you, Mr. Vandiver.

MR. VANDIVER: Thank you.

BY MR. VANDIVER:

Q And I just wanted to give you a second, Mr. Whale, to look at Mr. Zaetz's there and satisfy yourself that that is, in fact, the same document. And if you look at WMZ-1, Page 9 of 45, and compare that to this page, and just satisfy yourself that that is, in fact, identical. I think the date up there in the right-hand corner may be different, but I think we looked at them and satisfied ourselves of it.

A Yes.

Q Okay, sir. We are going to have to do this one more time, but --

A That's fine.

Q Now, Mr. Whale, do you recognize this document, this OPA document?

A Yes, I do.

Q And is it a normal document prepared by -- is it a document prepared by Tampa Electric Company in its normal course of business?

A We track OPA. This particular document is a specific one the general manager prepared for that particular station at that time.

Q Okay. And is this chart part of the Gannon 2003 business plan?

A Yes, it was.

Q With that introduction, Mr. Whale, could you tell me what the peak availability percentage for Gannon was in 2001?

A This graph is for Gannon Station proper, so it has got Gannon 5 and 6 embedded into this particular graph. This is not a graph of 1 through 4, so we need to keep in mind that we are looking at a Gannon Station proper, not 1 through 4.

Q So it is all six units?

A This is all six units displayed here.

Q Okay. And I guess the analysis down there reflects that -- reflects that the drop in OPA is due to the decreasing O&M and capital budgets, and is that a reflection -- is that one side of the coin of the patch and go that you referenced earlier?

A The patch and go maintenance practice did avoid spending major capital investments and replacing components that would not be -- again, we would be shutting down and those components would not have the useful life utilized for them. The patch and go was more of a maintenance cost, but kept the availability of the units during the short time period that we saw them running.

Q Okay. Now, I think you are going to disagree with this statement. Isn't OPA the most important indicator, important measure for plant performance and reliability?

A No, it is just one of many. Again, as far as total availability of the units, EAF, which is equipment availability factor, is the most important of the availability factors. OPA just gives us a measure of when the peaks are coming in, how we are addressing the peaks.

Q Who is Buddy Maye?

A Buddy Maye is the president and general manager of Bayside and Gannon.

Q And Mr. Maye told me in his deposition that he has worked at Gannon for about the past 20 years, isn't that correct?

A A long time, yes.

Q Yes, sir. I'm going to hand you a copy of Mr. Maye's deposition, and I am going to refer you to a section of that. Specifically, Page 37. And take a look at Lines 15 and 16 there. Can I get Mr. --

MR. VANDIVER: In fact, Commissioners, I have been rather remiss thus far in my cross. I need to get all of these things marked as an exhibit, Madam Chairman, if I could. I think the next number was 14. I have not done a very good job of getting these things marked.

CHAIRMAN JABER: Okay. Let me have a short title, Mr. Vandiver, on the -- what looks like an e-mail cover page from Mr. Hemrich.

MR. VANDIVER: Yes. That would be the -- let's call that the Hemrich memo. However you pronounce this gentleman's name. Maybe you could help me, Mr. Whale. Chuck Hemrich?

THE WITNESS: I'm sorry, repeat the question.

MR. VANDIVER: How do you pronounce Mr. Hemrich's name?

THE WITNESS: H-E-M-R-I-C-H.

MR. VANDIVER: And that would be Exhibit Number 14, I believe.

CHAIRMAN JABER: The August 7th, 2002 Hemrich is Exhibit 15.

MR. VANDIVER: And then I believe the next one was the OPA, which would be 16.

CHAIRMAN JABER: Okay. The on-peak availability document dated March 12th, 2003 --

MR. VANDIVER: Would be Number 16.

CHAIRMAN JABER: -- is identified as Exhibit Number 16.

MR. VANDIVER: And now the Buddy Maye deposition would be Number 17.

CHAIRMAN JABER: You didn't want the EAF document?

MR. VANDIVER: Not yet. It's next.

CHAIRMAN JABER: And the date of the deposition is what, Mr. Vandiver?

MR. VANDIVER: I believe it is May 13th. May 13th.

CHAIRMAN JABER: May 13 deposition transcription of Buddy Maye, M-A-Y-E --

MR. VANDIVER: M-A-Y-E.

CHAIRMAN JABER: -- will be identified as Exhibit Number 17.

(Exhibits 15 through 17 marked for identification.)

MR. VANDIVER: Thank you, Madam Chairman.

BY MR. VANDIVER:

Q And there back at Mr. Maye's deposition, I believe I asked him -- I asked him what he thought the most important reliability factor was, and he opined that it was, in fact, OPA, did he not?

A Yes, he has. In his deposition he said OPA, on-peak availability.

Q And that was Mr. Maye's opinion?

A That's correct.

Q And I believe in your deposition that we just did earlier this week, I asked you the identical question, did I not?

A I don't remember.

Q Okay. Can we get Mr. Whale a copy of his deposition, please, and I believe that would be number --

CHAIRMAN JABER: I will worry about the numbers, you worry about getting me the documents.

MR. VANDIVER: Yes, ma'am. It's coming.

BY MR. VANDIVER:

Q And if we could take a look at your deposition, I think that is on Page 36 at Line 22. I asked you the identical question, and you opined that EAF was the most important one.

A Repeat that page again.

Q Yes, sir. Page 36 at Line 22. I asked you the same question. I said almost the identical question.

A It starts on Page 35, not 36.

Q I apologize.

A Yes, I've got it.

CHAIRMAN JABER: Mr. Vandiver, let me get caught up with you.

MR. VANDIVER: Yes, ma'am.

CHAIRMAN JABER: The transcript you just handed out, the deposition transcript of Mr. Whale, did you want that identified as an exhibit?

MR. VANDIVER: Yes, ma'am.

CHAIRMAN JABER: Okay. The October 28th, 2003, depo transcript for William Whale is identified as Exhibit Number 18.

(Exhibit 18 marked for identification.)

CHAIRMAN JABER: Now, I confess I didn't hear your question, so I need you to repeat your question.

MR. VANDIVER: Okay.

BY MR. VANDIVER:

Q I asked Mr. Whale, I said in your deposition you stated that you thought the equivalent availability factor, or EAF, was the most important factor, is that correct?

A That is correct.

Q Okay.

MR. VANDIVER: And at this juncture, Commissioners, I know we are putting in a lot of paper, but this is the last one for awhile. I wanted to introduce the EAF chart and go to that, since we were on this subject. And I guess the next number --

CHAIRMAN JABER: Okay. The equivalent availability factor document dated March 12th, 2003 will be identified as Exhibit Number 19.

MR. VANDIVER: Thank you.

(Exhibit 19 marked for identification.)

BY MR. VANDIVER:

Q And do you have that document, Mr. Whale? I know it is a lot of paper at one time.

A Bates stamped 1817.

Q Yes, sir.

A Okay.

MR. VANDIVER: And, Mr. Beasley, for your information, there is an identical thing in Mr. Zaetz's exhibit Page 3 of 45. And, again, that is a confidential exhibit.

MR. BEASLEY: That's fine. We will agree to the same thing you did on the earlier one.

MR. VANDIVER: Fair enough. This is not confidential, but it is contained in his confidential exhibit, again. There was a lot of paper flying around with our production of documents.

CHAIRMAN JABER: Okay.

BY MR. VANDIVER:

Q And, again, Mr. Whale, except for the dates and Bates stamped pages, do you believe these pages to be identical?

A Yes.

Q Okay, thank you. Now, this chart is also a part of the Gannon business plan and prepared in the normal course of business by Tampa Electric employees?

A That's correct.

Q Okay. And you recognize this chart, as well, do you not?

A Yes, I do.

Q And at the bottom of this page, does the analysis reflect that the equivalent availability factor is 3.5 percent better than last year and 1.1 percent better than the five-year average?

A Yes, it says that.

Q Okay. And this, in your mind, is the most important reliability factor and it reflects an improving Gannon Station, does it not?

A Yes. This document is a Gannon Station -- again, this is not -- this has got all the units, Gannon 1 through 6 involved in it. And the improvement in 2002 -- now, the 2002 is a 9 plus 3, so it has got three months of projection. But, again, it was due to the patch and go was working as far as keeping the units available versus the planned outages. This is really the whole station. If you have the interrogatories, you will see that there are specifics on Gannon 1 through 4 that shows them down into the 60s.

Q Okay. Mr. Maye suggested that the dip in 2000 was due to the after effect of the Gannon 6 explosion, do you agree?

A Repeat that question.

Q Yes, sir. The dip in 2000 there, Mr. Maye suggested that that was due to the after effect of the Gannon 6 explosion. Do you agree with that?

A The Gannon 6 explosion occurred in the earlier part. The 2000 dip was primarily due to a generator issue on Gannon Number 6.

Q Okay. If we could go to Page 16 of your testimony, please, sir. You state that it would cost 57 million, I think it is 57.4 to keep Gannon 1 through 4 operating somewhat reliably, is that correct?

A That's correct.

Q And I think we established in your deposition that somewhat reliably meant an EAF this same -- this equivalent availability factor of 80 to 85 percent, is that correct?

A Correct.

Q Okay. Now, at this time I would like to refer you to Mr. Majoros' testimony, if I could, sir, because this EAF factor is a very important thing and it is used throughout the testimony. And specifically I would like to go to -- I think it is MJM-6. And the MJM-6, I believe -- this document, the MJM-6 document, this is a Tampa Electric document, is it not, sir?

A Yes, it is.

Q Okay. And this 80 to 85 percent reliability on Bates stamped 2289 and the next page, the 60 percent availability, that is also the EAF number, is it not?

A That is correct.

Q Okay, sir. Now, do you think it is realistic to expect Gannon 1 through 4 to perform at an EAF of 80 to 85 percent?

A Yes, I do. Gannon Station had performed at an 80 percent availability. As far as Gannon 1 through 4, they have done it before.

Q When did they do it?

A In 1999, Gannon 1 was 83.5, Gannon 2 was 88.5, Gannon 3 was 86.0. Gannon 4 did not do it, it was 69.5 that particular year. The '95 to '98 average for Gannon 4 was 97.9.

Q Could we go to Page 80 of the deposition of Buddy Maye, please, sir.

A Page 80 of my deposition?

Q No, sir, of Buddy Maye's deposition.

A All right.

Q Now, we are referencing there -- I think we need to start on Page 79, sir. And if you look at the bottom of Page 79 at Lines 22 through 25. Are you with me, sir?

A Yes, I am.

Q Okay. And do you see the question there?

A Yes, I do.

Q Okay. And following on the next page?

COMMISSIONER BRADLEY: The question that you are referring to, is that on Line 21?

MR. VANDIVER: Yes, sir. Where I say okay, sir, yes. And following on to the next page.

BY MR. VANDIVER:

Q And following on to the next page there at Line 22 on Page 80, how realistic is it for the Gannon units to run at 85 percent capacity today.

A Yes, I see that.

Q And what was Mr. Maye's answer there?
A "It is not very realistic. And really that's what this document represents. It comes at a significant price."
Q And could you read the next question and answer, please.
A "Right. And do you believe it to be, in your expert opinion to be cost-effective to run Gannon units at 85 percent availability?"
Q Could you read the answer, please.
A "At this point in time only being permitted in any shape or form not to run past December 31st of 2004, it is not a wise investment."
Q And the next question and answer, please.
A "It wouldn't be cost-effective, and you wouldn't recommend it to anyone to run them at 85 percent capacity and to spend this money?"
Q And the answer.
A "No."
Q Okay. And you disagree with that, sir?
A No, I don't disagree with it. The units can run at 85 percent, but you would have to have the investment that we stated to reach that 85 percent.
Q Okay. So, I guess my question is the -- your testimony says to get these units operating somewhat reliably it would cost $57.4 million, and to try and keep them operating

beyond the actual current planned shutdown dates, and you agree that it would not be a wise investment?

A The investment that would be required on the particular units, the patch and go repairs were only going to get to a certain point to where we could not continue to do the patch and go repairs, and that is where we were going to have to go into major component change-outs, which is going to be a large capital investment.

And at that point you are having to make that investment. And for the time period that the units would be available to run, it wouldn't be a wise investment. One, because there would be a substantial planned outage required of which we would have to work into the outage schedule which would mean purchasing power. Two, there would be at least a six-month procurement process, if we could obtain the tubes domestically.

And today where there is not a lot of suppliers, we would have to go international to obtain the tubes. And that is just to address the cyclones. That is not addressing the other issues associated with the units, and that would be an impractical approach.

Q Okay. Now, the significant difference, looking at Mr. Majoros' testimony, the significant difference, and as I understand it, we talked about it a little bit in your deposition, the difference between the 80 to 85 percent availability that was prepared here in Mr. Majoros' testimony in March, and the 57 million which I understand was prepared in September -- I don't want to get into your rebuttal, but that was prepared in September.

A Right.

Q Is basically the difference between the 80 to 85 percent on 2289 and 2290 is the cyclones, is that correct?

A That's correct. That is the bulk of it is replacing the cyclones.

Q Yes, sir. And as I understand of the cyclone issue, there is a total of 14 cyclones in the four Gannon units, is that correct?

A Thirteen; not 14, 13.

Q Thank you.

CHAIRMAN JABER: Mr. Vandiver, when you get to the point where it makes sense to take a break, we will go ahead and break for lunch.

MR. VANDIVER: Okay. Maybe we can break after this cyclone deal. Madam Chairman, I hope you are keeping track of the numbers.

CHAIRMAN JABER: Yes.

MR. VANDIVER: Good. I will wait until Mr. Poucher has finished handing this out.

CHAIRMAN JABER: Mr. Beasley, do you have a copy of the exhibit now?

MR. BEASLEY: I do.

CHAIRMAN JABER: Okay.

THE WITNESS: Commissioners, let me make a change. There are 14 cyclones. I was confused. Gannon Number 3, I thought, had three cyclones; it has four.

MR. VANDIVER: If we can get a copy to Mr. Maye.

CHAIRMAN JABER: Mr. Beasley, you said you have a copy of the last document handed out?

MR. BEASLEY: Yes, ma'am.

CHAIRMAN JABER: Okay. The March 3rd, '03, e-mail, it looks like, from Mr. Edwards to Mr. Maye and others will be identified as Exhibit Number 20.

(Exhibit 20 marked for identification.)

BY MR. VANDIVER:

Q Mr. Whale, I have given you an e-mail from Gene Edwards to Buddy Maye, to himself, John Knight, and Tim Panoff.

A That's correct.

Q You were copied on it, sir?

A Yes, I am.

Q A long time ago?

A Uh-huh.

Q March of '03. Can you identify this for me, please, sir?

A Yes. It is an e-mail from Gene Edwards to Buddy Maye, himself, John Knight, and Tim Panoff.

Q And this is the underlying -- this is about cyclone repair, is it not, sir?

A That is correct.

Q And this references that there are, in fact, 14 cyclones at the four units, is that correct?

A That's correct.

Q And it is my understanding that this is the underlying basis for the $21 million figure?

A I don't know that for a fact.

Q But is it your testimony that each one -- well, there is 14 cyclones at 1.5 million per cyclone to repair them, that would come out to about $21 million?

A If you say it adds up. I don't have a calculator here with me.

Q I don't, either. I'm just kind of eyeballing it. I'm curious as to did all 14 cyclones wear out at the same time?

A All four units were experiencing problems with cyclone issues. The cyclones, themselves, were wearing; they had a different rate of wearing. I see on here that it says the cyclones were last replaced in the 1993/'94 time period. That is incorrect. Gannon 1 and 2 were changed out in 1976.

Q So Units 1 and 2 were replaced in '76. Do you know when Units 3 and 4 were replaced?

A Units 3 and 4 were changed out in 1991 and 1994.

Units 3 and 4 had a different wear rate it appears. In '76 to '85, the units were experiencing oil conversion of which the cyclones were changed out, and oil conversion doesn't -- when you're burning oil in the cyclones, it is not as wearing as coal is. And when we changed them over to coal, that is when the wear starts taking on them, and that was done in '85. The cyclones on 3 and 4, for whatever reason, didn't last as long, and they had to change it out in '91, and then we experienced the same problems with them rolling into 2000.

Q So it is your testimony that all 14 -- you had no alternative but to replace all 14 of them at a cost of $21 million, correct?

A To obtain the reliability that we needed, yes, that is correct. The cyclones, it reached a point where we had so many tube leaks in them that we were not able to sustain fire in the cyclone. We had several cases where the tube leaks were actually blowing the flames out, and we couldn't hold it on line. So you reach a point where when you can't even hold the water and hold the flame, you have got to take the unit off and go in and do a patch and go. And that is a technique called pad welding.

CHAIRMAN JABER: What part of the unit is the cyclone? Remind me what it looks like.

THE WITNESS: The cyclone is in the front of the unit. These are different than the Riley turbos that have a fire from both sides and are spinning. These are right on the front. The coal drops in, it spins the coal in that particular component, and completes combustion, and then blows out into the furnace, and then out through the convection pass.

CHAIRMAN JABER: Is there a standard period of time they are supposed to operate without replacement or any sort of patch work?

THE WITNESS: You look 10 to 15 years on a boiler component to last. Different ones will go a little longer or a little less, depending on whether some other mechanisms come into play. On these particulars we had the wear of the coal, but we also started having issues of pluggage. These tubes are very old, and the material inside is getting into the water circuits which plugs the tube, and then when you have it hot on the outside and it is plugged and it doesn't have the water to cool it, and then the tube fails.

We also had another issue called hydrogen embrittlement enter into it, and that is because of the condensers that were leaking, and it was disrupting the border chemistry and causing problems there. So we had some multiple mechanisms giving us problems with the cyclones.

CHAIRMAN JABER: And forgive my ignorance on this issue, are cyclones readily available in the industry or did you have to be on a waiting list?

THE WITNESS: No, Chairman, those are special order components. They have to fabricate them. Nobody has those sitting on stock. They are rather large. They are about 200 foot in diameter, and they have to be manufactured and assembled.

CHAIRMAN JABER: So did you have to preorder them well in advance to be able to replace all 14?

THE WITNESS: Yes, you do. You have to order them well in advance. Again, one, you have just got to find somebody that has these tubes available. Let me give you maybe a visual help. This is a brand new cyclone tube. You can see that it has got studs on it. You can see it is rather thick because of the pressures that it is dealing with, and it doesn't have a large area for water to flow which causes the pluggage problem.

CHAIRMAN JABER: You didn't just preorder the cyclone tubes, you ordered the entire unit?

THE WITNESS: You order the entire units.

CHAIRMAN JABER: And how far in advance did you have to preorder?

THE WITNESS: We did not make this order because of the fact of knowing how long it would take. We look at a minimum of six months just to get the order in. That is not the outage period to install them, which would be much longer.

CHAIRMAN JABER: And how much longer?

THE WITNESS: That would be least a 7 to 8 week planned outage. Forty-nine days is what we kind of estimated. That is a very aggressive schedule.

These are the cyclone tubes out of Gannon 4 that we cut out. If you will notice, one, there is an immense amount of erosion on the top of them. If you will also look, these massive metal humps where you would normally have studs is where the welders have gone in and tried to patch that. If you will notice there is a major crack going through there. And what we do is just go in and weld there versus trying to cut all these tubes out in this large diameter and replace the new one.

CHAIRMAN JABER: Mr. Whale, let me interrupt you, because I know I'm about to get an objection. I just wanted to know for the sake of going forward what the cyclone unit looks like. Let me let your attorney do that stuff on redirect, if it is necessary. You are going outside the scope of my question. And you stand between us and lunch.

Mr. Vandiver, go ahead.

MR. VANDIVER: Okay.

BY MR. VANDIVER:

Q So you had no alternative but to replace all 14?

A We had reduced header pressure. As we started having tube failures with these units, we went into the patch and go, but we also went into a technique of reducing the header, which is reducing the internal steam pressure within the tubes, to try to buy some more safety margin. We had dropped -- there is only a certain point that you can do that. That also provided us a safety margin for some of the tube failures that we were experiencing on the external side of the boilers.

We had gotten down as far as we could go in reducing that header pressure, and the pad welds as far as we had gone with that, and we were left with really no other alternative than to say we are going to just either start it up and run it for 24 hours, come back down, and send a bunch of welders in and pad weld it, start it back up and come back down. And it wasn't working anymore.

Q I'm curious as to your 85 percent call. Looking at the EAF, it looks to me like Gannon for the past five years was nowhere close do 85 percent. And it looks like now all of a sudden we are trying to run Gannon at 85 percent. And I'm curious as to why all of a sudden we are trying to run Gannon at 85 percent.

A Again, that system graph, that is a system graph that has Gannon 1 through 6 in it. Gannon 1 through 4 had ran at the 83 and 88 percent. Again, that had Gannon 5 and 6 in it which was major problems as far as those units, and those are the reasons we repowered them. Gannon 1 through 4 had run at the 80 percent availability.

The other trick about the 80 percent availability is that gives a high confidence factor in planning what we are going to do as far as the system. When we are taking these units and saying that we are going to depend on them and they are not there, then we end up having to go out and purchase power on the spot market and those things, which is not in the -- it really creates a lot of problems in the planning process.

Q Aren't Gannon 5 and 6 the newest of the units? I mean, 1 and 2 were built first, right, then 3 and 4, then 5 and 6?

A Correct.

Q It seems contraindicated that 5 and 6 would be the worst.

A Gannon 5 and 6 are a different designed boiler. Those are Riley turbo-fired boilers, and those particular boilers had different mechanisms that cause problems with them. They had much higher capacity. And when those things went off, that really impacted the availability of Gannon because of the fact the equation is based on both the megawatts and the availability. Gannon 6 is a 360-megawatt machine. When that one came off, that was like 2 or 2-1/2 of Gannon 1 and 3. So it did impact the availability of the units.

Q Back to the Exhibit Number 14 or 15, the Chuck Hemrich memo where you were looking at the $4 million estimate, to do some of this cyclone repair work for $4 million?

A That was repairs to cyclone duct work, screen weld equipment. That was some general line items that they had just identified for those dollars.

Q So things really changed a lot in the six-odd months between August and March?

A During 2002, again, they were looking at -- we were trying to evaluate what is the best place to put money along with several other factors. We had the safety, we had the reliability, we had the construction issues, and our employee issues to deal with. This was just one piece of it.

We went into those looking at the outages, doing the best that we could within the 28 days. We also had the problems in those years of trying to fit these outages in at the same time that we got the Big Bend outages. As a choice between doing work on Big Bend or doing work on Gannon, the Big Bend units had much more capacity on them and much more as far as time and life. So we were going to address the Big Bend units versus the Gannon units, if there was a choice of that outage time period.

CHAIRMAN JABER: Mr. Vandiver, we are going to stop right here and come back at 2:15. Thank you.

MR. BADDERS: If I may, we actually would like to waive other cross-examination on Issue 30, of the witnesses on Issue 30, and I would ask to be excused.

CHAIRMAN JABER: Mr. Badders, remind me. Issue 30 you wanted to initially stick around because you weren't sure if there would be a stipulation reached?

MR. BADDERS: Actually we were thinking we may have some questions on cross-examination for some of the witnesses, but we will not.

CHAIRMAN JABER: Okay. You are excused from the hearing. Thank you.

(Lunch recess.)

(The transcripts continues in sequence with Volume 3.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 24th day of November, 2003.

Jane Faurot

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