BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 040001-EI

In the Matter of

UEL AND PURCHASED POWER
OST RECOVERY CLAUSE WITH
ENERATING PERFORMANCE INCENTIVE
ACTOR.
_________________________________/

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VOLUME 2

Pages 189 through 300

ROCEEDINGS: HEARING

EFORE: CHAIRMAN BRAULIO L. BAEZ
COMMISSIONER J. TERRY DEASON
COMMISSIONER RUDOLPH "RUDY" BRADLEY
COMMISSIONER CHARLES M. DAVIDSON

DATE: Monday, November 8, 2004

TIME: Commenced at 9:30 a.m.

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

REPORTED BY: LINDA BOLES, RPR
Official FPSC Reporter
(850) 413-6734

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD
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P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

PROGRESS ENERGY FLORIDA

DOCKET NO. 040001-EI

FUEL ADJUSTMENT PROCEEDINGS

DIRECT TESTIMONY OF

SAMUEL S. WATERS

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

A. My name is Samuel S. Waters and I am employed by Progress Energy Carolinas (PEC). My business address is 410 S. Wilmington Street, Raleigh, North Carolina, 27601.

Q. Please tell us your position with PEC and describe your duties and responsibilities in that position.

A. I am Manager of Resource Planning for Progress Energy Florida (PEF or the Company) and Progress Energy Carolinas. I am responsible for directing the resource planning process for both companies. Our resource planning process is an integrated approach to finding the most cost-effective alternatives to meet each company's obligation to serve, in terms of long-term price and reliability. We examine both supply-side and demand-side resources available and potentially available to the Company over its planning horizon, relative to the Company's load forecasts. In my capacity as Manager of Resource Planning, I oversaw the completion of the Company's most recent TYSP document filed in April 2004.

Q. Please summarize your educational background and employment experience.

A. I graduated from Duke University with a Bachelor of Science degree in Engineering in 1974. From 1974 to 1985, I was employed by the Advanced Systems Technology Division of the Westinghouse Electric Corporation as a consultant in the areas of transmission planning and power system analysis. While employed by Westinghouse, I earned a Masters Degree in Electrical Engineering from Carnegie-Mellon University.

I joined the System Planning department of Florida Power & Light Company (FPL) in 1985, working in the generation planning area. I became Supervisor of Resource Planning in 1986, and subsequently Manager of Integrated Resource Planning in 1987, a position I held until 1993. In late, 1993, I assumed the position of Director, Market Planning, where I was responsible for oversight of the regulatory activities of FPL's Marketing Department, as well as tracking of marketing-related trends and developments.

In 1994, I became Director of Regulatory Affairs Coordination, where I was responsible for management of FPL's regulatory filings with the FPSC and the Federal Energy Regulatory Commission (FERC). In 2000, I returned to FPL's Resource Planning Department as Director.

I assumed my current position with Progress Energy in January of this year. I am a registered Professional Engineer in the states of Pennsylvania and Florida, and a Senior Member of the Institute of Electrical and Electronics Engineers, Inc. (IEEE).

Q. Have you previously testified before this Commission?

A. Yes. I have testified in several dockets related to resource planning and the need for power.

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

A. My purpose in this testimony is to support the Company's request for approval of two recent long term purchase agreements. While the agreements do not call for the delivery of energy and capacity until 2007 and 2010, the purchases are components of the resource plan to meet our obligation to provide adequate and reliable electric service to our customers. Specifically these long term agreements are needed to maintain the 20 percent reserve margin. There would be a significant lead time associated with pursuing other alternatives to these agreements. For this reason we request a finding by the Commission that the agreements are a reasonable and prudent means to meet our long term resource plan. In his testimony, Mr. Portuondo discusses the appropriate recovery mechanism for recovery of energy and capacity payments as power is delivered under the agreements.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my testimony:

SSW-1 Tolling Agreement between Shady Hills Power Company, L.L.C. and Florida Progress Corporation, d/b/a Progress Energy Florida, Inc.

SSW-2 Letter of Intent to Purchase Capacity and Energy from Southern Companies

SSW-3 Summary of Costs and Benefits of the Shady Hills Tolling Agreement

SSW-4 Summary of Costs and Benefits of the Unit Power Sales Agreement with the Southern Companies

They should be marked as Ex.___ (SSW 1 -4).

Q. Please describe the new agreements.

A. Progress Energy has entered into an agreement with Shady Hills Power Company, LLC, to purchase the output of a facility nominally rated at 517 MW, for the period April 1, 2007 through April 30, 2014. It is a tolling agreement meaning that Progress Energy will purchase the fuel supply for the Shady Hills facility and receive all of the output. This purchase is needed to maintain a 20% reserve margin for the PEF system during that timeframe. The contract provides savings compared to constructing the 2006 combustion turbine facilities presented in the PEF 2004 Ten Year Site Plan.

In addition, PEF has signed a Letter of Intent with the Southern Companies to extend the existing 1988 Unit Power Sales Agreement. The anticipated term of this extension is June 1, 2010 through May 31, 2015. The capacity purchased under this contract is needed to maintain the 20 percent reserve margin for the PEF system and provides important strategic benefits to customers as well. Copies of the Shady Hills Tolling Agreement and the Letter of Intent with the Southern Companies are provided in my Exhibits ___ (SSW-1) and ___ (SSW-2).

Q. Please describe the contract with Shady Hills Power Company, LLC in more detail.

A. As I mentioned above, the agreement with Shady Hills Power Company, LLC is a tolling agreement whereby PEF will provide fuel to the Shady Hills facility, located in Pasco County, Florida, and receive the power output of the facility. The facility consists of three combustion turbines with a guaranteed heat rate of 10,400 Btu/kWh. Capacity of the units is seasonally adjusted, based on a nominal rating of 517 MW, from 478 MW, summer, to 520 MW, winter. Capacity charges vary seasonally, averaging [redacted] per kW per month. A variable O&M charge is applied, depending on the fuel used in the facility: [redacted]/MWh when running on gas, [redacted]/MWh when running on oil.

Q. Does this contract provide savings to PEF customers?

A. Yes. PEF had identified construction of three combustion turbines in its 2004 Ten Year Site Plan, to be placed in service in December, 2006. Purchase of capacity from the Shady Hills facility provides savings of $55.4 million, CPVRR, when compared to construction of these facilities, as shown in my Exhibit ___ (SSW-3). The purchase of this capacity from the Shady Hills facility will defer the need for the combustion turbines beyond the planning horizon shown in the 2004 Ten Year Site Plan.

Q. Please describe the proposed agreement with the Southern Companies in more detail.

A. The proposed purchase is envisioned to be an extension of a long-standing agreement with the Southern Companies which has provided substantial benefits to PEF customers. PEF is currently negotiating with the Southern Companies to purchase 425 MW of capacity for the period June 1, 2010 through May 31, 2015, to be provided from Georgia Power Company's Scherer 3 coal-fired unit (74 MW) and Franklin 1 combined cycle unit (351 MW), based on the current demonstrated capabilities of these units. The agreement specifies levelized capacity charges of [redacted] per kW per month for the Scherer capacity, and [redacted] per kW per month for the Franklin capacity. The capacity prices cover capital costs, costs of non-environmental capital additions, fixed O&M and allocated overhead expenses. PEF will also be charged the costs of fixed transportation required to deliver gas to the Franklin facility, and the costs of electrical transmission to the Florida-Georgia interface. Energy charges for these facilities will be based on delivered fuel prices, times a guaranteed heat rate at the Franklin unit, and the actual heat rate used at the Scherer unit.

Q. Does this contract provide savings to PEF customers?

A. Yes. The contract is expected to save PEF customers approximately $2.4 million, CPVRR, over the term June 1, 2010 through May, 2015, as shown in my Exhibit ___ (SSW-4). Under alternative assumptions regarding the availability of economy energy from the Southern system, the agreement would be expected to lose approximately $2.4 million, CPVRR. While I conclude that it is reasonable to expect net savings from this contract it should be noted that the range of predicted benefits, depending on the assumptions made in calculating them is from moderately positive to negative to the same degree. However in my judgment this range of potential benefits is acceptable because of the strategic value of this contract. Purchase of this capacity is expected to defer the need for a May, 2010 combined cycle unit, as discussed in PEF's 2004 Ten Year Site Plan.

Q. Does this contract provide other benefits to PEF customers?

A. Yes. In addition to the economics of the purchase, the contract will provide the following benefits:

- Contributes to fuel diversity - A portion of the energy will come from coal-fired generating capacity, providing low-cost energy and serving to reduce the price volatility of PEF's fuel mix.
- Contributes to economy energy availability – Access to the transmission facilities provided by the agreement will give PEF access to lower cost energy that may be available within the Southern region, in those hours when the units specific to the purchase are not scheduled.
- Contributes to increased reliability - The agreement will maintain a transmission path to the Southern system, which provides access to a large resource pool and enhances system supply reliability.
- Contributes to cost certainty - The purchases come from existing generating facilities. Utilization of existing resources provides greater assurance of cost and performance than might be obtained from units that would need to be constructed.
- Contributes to increased access to coal resources - The agreement is expected to provide a right-of-first refusal to the output of additional coal capacity in the Southern system, should that capacity not be returned to retail rate base.

Q. When is the agreement with the Southern Companies anticipated to be completed?

A. Negotiations are underway, and it is expected that a final agreement will be in place by the end of October.

Q. What action should the Commission take at this time, regarding these two agreements?

A. The Commission should find that entering these two agreements at this time is a reasonable and prudent action by the Company to maintain a 20% reserve margin over the long term. Recovery of energy and capacity costs pursuant to the agreements would be permitted subject to a finding of reasonableness and prudence at the time the expenses are presented for cost recovery.

Q. Does this conclude your testimony?

A. Yes.

Prepared Direct Testimony and Exhibits of Samuel S. Waters

Errata Sheet

Testimony

Page 3, strike from the word "two" on line 2, through the end of line 11, and replace with the following:

> a recent long term purchase agreement. While the agreement does not call for the delivery of energy and capacity until 2007, the purchase is a component of the resource plan to meet our obligation to provide adequate and reliable electric service to our customers. Specifically this long term agreement is needed to maintain the 20 percent reserve margin. There would be a significant lead time associated with pursuing other alternatives to this agreement. For this reason we request a finding by the Commission that the agreement is a reasonable and prudent means to meet our long term resource plan. In his testimony, Mr. Portuondo discusses the appropriate recovery mechanism for recovery of energy and capacity payments as power is delivered under the agreement.

Page 3, strike lines 17, 19 and 20 in their entirety

Page 4, strike the letter "s" from the word "agreements" on line 1.

Page 4, strike lines 9 through 15 in their entirety

Page 5, strike line 12 through line 20 on page 7 in their entirety

Page 7, strike "these two agreements" on lines 22 and 23, and replace with "this agreement".

Page 8, strike "these two agreements" on line 1, and replace with "this agreement".

Page 8, strike the letter "s" from the word "agreements" on line 3.

Exhibits

Strike Exhibits SSW-2 and SSW-4 in their entirety.

11/8/04

PROGRESS ENERGY FLORIDA

DOCKET NO. 040001-EI

GPIF Reward/Penalty Amount for
January through December 2003

DIRECT TESTIMONY OF
MICHAEL F. JACOB

Q. Please state your name and business address.

A. My name is Michael F. Jacob. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am employed by Progress Energy Carolinas as Manager of Generation Modeling and Analysis.

Q. Have your responsibilities as Manager of Generation Modeling and Analysis remained the same since you last testified in this proceeding?

A. Yes, my responsibilities regarding the preparation of the Generation Performance Incentive Factor (GPIF) filing requirements for Progress Energy Florida (the Company) have remained the same.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the Company's GPIF reward/penalty amount for the period of January through December 2003. This calculation was based on a comparison of the actual performance of the Company's seven GPIF generating units for this period against the approved targets set for these units prior to the actual performance period.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. _______ (MFJ-1T), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 24-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. What GPIF incentive amount have you calculated for this period?

A. I have calculated the Company's GPIF incentive amount to be a reward of $2,139,695. This amount was developed in a manner consistent with the GPIF Implementation Manual. Page 2 of my exhibit shows the system GPIF points and the corresponding reward. The summary of weighted incentive points earned by each individual unit can be found on page 4 of my exhibit.

Q. How were the incentive points for equivalent availability and heat rate calculated for the individual GPIF units?

A. The calculation of incentive points was made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on each unit's Generating Performance Incentive Points Table found on pages 9 through 15 of my exhibit.

Q. Why is it necessary to make adjustments to the actual performance data for comparison with the targets?

A. Adjustments to the actual equivalent availability and heat rate data are necessary to allow their comparison with the "target" Point Tables exactly as approved by the Commission prior to the period. These adjustments are described in the Implementation Manual and are further explained by a Staff memorandum, dated October 23, 1981, directed to the GPIF utilities. The adjustments to actual equivalent availability concern primarily the differences between target and actual planned outage hours, and are shown on page 7 of my exhibit. The heat rate adjustments concern the differences between the target and actual Net Output Factor (NOF), and are shown on page 8. The methodology for both the equivalent availability and heat rate adjustments are explained in the Staff memorandum.

Q. Have you provided the as-worked planned outage schedules for the Company's GPIF units to support your adjustments to actual equivalent availability?

A. Yes. Page 23 of my exhibit summarizes the planned outages experienced by the Company's GPIF units during the period. Page 24 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 040001-EI

GPIF Targets and Ranges for January through December 2005

DIRECT TESTIMONY OF MICHAEL F. JACOB

Q. Please state your name and business address.

A. My name is Michael F. Jacob. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am employed by Progress Energy Carolinas as Manager of Generation Modeling and Analysis.

Q. Have your responsibilities as Manager of Generation Modeling and Analysis remained the same since you last filed testimony in this proceeding?

A. Yes, my responsibilities regarding the preparation of the Generation Performance Incentive Factor (GPIF) filing requirements for Progress Energy Florida (the Company) have remained the same.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the development of the Company's GPIF targets and ranges for the period of January through December 2005. These GPIF targets and ranges have been developed from individual unit equivalent availability and average net operating heat rate targets and improvement/degradation ranges for each of the Company's GPIF generating units, in accordance with the Commission's GPIF Implementation Manual.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. ____ (MFJ-1) which consists of the GPIF standard form schedules prescribed in the GPIF Implementation Manual and supporting data, including unplanned outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units. This 95-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. Which of the Company's generating units have you included in the GPIF program for the upcoming projection period?

A. For the 2005 projection period, the GPIF units are the same as for the current period, Anclote Units 1 and 2, Crystal River Units 1 through 5, Hines Unit 1, and Tiger Bay. Combined, these units account for 81.0% of the estimated total system net generation for the period.

The Company's Hines Unit 2 was not included for the upcoming projection period since there is not sufficient performance history to use in setting targets and ranges for the unit.

Q. Have you determined the equivalent availability targets and improvement/degradation ranges for the Company's GPIF units?

A. Yes. This information is included in the GPIF Target and Range Summary on page 4 of my exhibit.

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the GPIF Implementation Manual. This includes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e., forced, partial forced, maintenance and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate (EUOR). From operational data and these graphs, the individual target rates are determined by inspecting two years of twelve-month rolling averages and the scatter of monthly data points during the two-year period. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage rates can then be converted into an overall equivalent unplanned outage factor

(EUOF). Because factors are additive (unlike rates), the unplanned and planned outage factors (EUOF and POF) when added to the equivalent availability factor (EAF) will always equal 100%. For example, an EUOF of 15% and POF of 10% results in an EAF of 75%.

The supporting tables and graphs for the target and range rates are contained in pages 49-95 of my exhibit in the section entitled "Unplanned Outage Rate Tables and Graphs."

Q. Please describe the methodology utilized to develop the improvement/degradation ranges for each GPIF unit's availability targets?

A. The methodology described in the GPIF Implementation Manual was used. Ranges were first established for each of the four unplanned outage rates associated with each unit. From an analysis of the unplanned outage graphs, units with small historical variations in outage rates were assigned narrow ranges and units with large variations were assigned wider ranges. These individual ranges, expressed in term of rates, were then converted into a single unit availability range, expressed in terms of a factor, using the same procedure described above for converting the availability targets from rates to factors.

Q. Have you determined the net operating heat rate targets and ranges for the Company's GPIF units?

A. Yes. This information is included in the Target and Range Summary on page 4 of my exhibit.

Q. How were these heat rate targets and ranges developed?

A. The development of the heat rate targets and ranges for the upcoming period utilized historical data from the past three years, as described in the GPIF Implementation Manual. A "least squares" procedure was used to curve-fit the heat rate data within ranges having a 90% confidence level of including all data. The analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in pages 30-48 of my exhibit in the section entitled "Average Net Operating Heat Rate Curves."

Q. How were the GPIF incentive points developed for the unit availability and heat rate ranges?

A. GPIF incentive points for availability and heat rate were developed by evenly spreading the positive and negative point values from the target to the maximum and minimum values in case of availability, and from the neutral band to the maximum and minimum values in the case of heat rate. The fuel savings (loss) dollars were evenly spread over the range in the same manner as described for incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of the weighting factors.

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of PROSYM simulations were made in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determine the contribution of each unit's availability to fuel savings. The heat rate contribution of each unit to fuel savings was determined by multiplying the BTU savings between the minimum and target heat rates (at constant generation) by the average cost per BTU for that unit. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

Q. What was the basis for determining the estimated maximum incentive amount?

A. The determination of the maximum reward or penalty was based upon monthly common equity projections obtained from a detailed financial simulation performed by the Company's Corporate Model.

Q. What is the Company's estimated maximum incentive amount for 2005?

A. The estimated maximum incentive for the Company is $9,314,504. The calculation of the estimated maximum incentive is shown on page 3 of my exhibit.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOANN T. WEHLE

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

A. My name is Joann T. Wehle. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of the Wholesale Marketing and Fuels Department.

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

A. I received a Bachelor's of Business Administration Degree in Accounting in 1985 from St. Mary's College, South Bend, Indiana. I am a CPA in the State of Florida and worked in several accounting positions prior to joining Tampa Electric. I began my career with Tampa Electric in 1990 as an auditor in the Audit Services Department. I became Senior Contracts Administrator, Fuels in 1995. In 1999, I was promoted to Director, Audit Services and subsequently rejoined the Fuels Department as Director in April 2001. I became Director, Wholesale Marketing and

Fuels in August 2002. I am responsible for managing Tampa Electric's wholesale energy marketing and fuel-related activities.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Florida Public Service Commission's ("FPSC" or "Commission") review, information regarding the 2003 performance of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 011605-EI and approved by the Commission in Order No. PSC-02-1484-FOF-EI. In addition, I will present details regarding the appropriateness for recovery of $108,746 in incremental operations and maintenance (O&M) expenses associated with hedging activities.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes. Exhibit No. ___ (JTW-1) was prepared under my direction and supervision. My exhibit shows Tampa Electric's calculation of its 2003 incremental hedging O&M expenses.

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

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

Q. What were the results of Tampa Electric's risk management activities in 2003?

A. As outlined in Tampa Electric's Risk Management Plan filed on September 12, 2003 in Docket No. 030001-EI, the company strives to reduce fuel price volatility while maintaining a reliable supply of fuel. Tampa Electric has established a hedging program to limit exposure to market price fluctuations of natural gas given the company's change in fuel mix. This program was reviewed and approved in March 2003 by the company's Risk Authorizing Committee (RAC). Tampa Electric has followed the program as approved by the RAC.

On April 1, 2004 Tampa Electric filed its annual risk management report, which describes the outcomes of its 2003 risk management activities. As that report indicates, Tampa Electric's hedging activities during 2003 produced a net savings of $29.5 million for Tampa Electric's customers.

Q. How did Tampa Electric's fuel mix change in 2003?

A. During 2003, Tampa Electric tested and brought on-line the natural gas fired Bayside Unit No. 1. Bayside Unit No. 2 was also tested during the fourth quarter of 2003 and became commercially operational on January 15, 2004. Both Bayside units are highly efficient, natural gas-fired combined cycle units. These units can serve base load, intermediate, and peaking needs depending on particular load and generation needs. These changes increased natural gas-fired generation for the company to twenty-one (21) percent of the total generation in 2003.

Q. Did the test and addition of the Bayside units impact Tampa Electric's hedging activity?

A. Yes. During the test phase, prior to commercial operation, the amount of run time and associated natural gas consumption of these units was uncertain. Even after

Bayside became commercially operational the performance characteristics and interplay of the individual combined cycle units continued to be analyzed and adjusted to maximize operating efficiency. Thus, the volume risk of natural gas hedged during 2003 was higher due to the addition of both Bayside units.

Q. Did the company conduct incremental hedging activities in 2003?

A. Yes, the company conducted several hedging related activities in 2003. These activities helped reduce fuel price risk and improve gas supply reliability. These activities included 1) executing numerous natural gas supply enabling agreements with a variety of counterparties to diversify the portfolio of suppliers for both price competitiveness and reliability of supply, 2) executing numerous electric power and transmission enabling agreements with a variety of counterparties to diversify the portfolio of suppliers for both price competitiveness and reliability of supply, 3) executing International Standardized Derivative Agreements to allow the execution of financial hedging transactions with a number of counterparties, 4) initiated the reorganization of hedging transaction responsibilities into a front, middle and back office structure consistent with industry standard concepts and 5) began the acquisition and implementation of a hedging information system. Furthermore, the company utilized a variety of financial hedging instruments including swaps, swing swaps, collars and options.

Q. What were the results of the company's incremental hedging activities?

A. The incremental hedging activities enhanced Tampa Electric's hedging processes, procedures, controls and capabilities. As a result, natural gas hedging activities protected Tampa Electric's customers from price volatility on [redacted] of the natural gas used in the company's plants.

Q. What were the costs associated with these transactions?

A. The net cost of that price protection in 2003 was a [redacted] when the instrument prices were compared to market prices on settled positions. The transaction costs associated with these transactions were embedded in the commodity price of the natural gas.

Q. Did the company use financial hedges for other commodities in 2003?

A. No, Tampa Electric did not use financial hedges for other commodities because of its fuel mix. Historically, Tampa Electric has primarily relied on coal as a boiler fuel. The price of coal is relatively stable compared to the prices of oil and natural gas, and there are no financial hedging instruments for the types of coal the company uses. The company also did not use financial hedges for oil or wholesale energy transactions. Tampa Electric consumes a small amount of oil, making price hedging somewhat impractical, and the company does not plan to use financial hedges for wholesale energy transactions until a liquid, published market exists in Florida.

Q. Does Tampa Electric use physical hedges?

A. Yes, Tampa Electric uses physical hedges in managing its coal supply. The company enters into a portfolio of differing term contracts with various suppliers to obtain the types of coal used on its system. In addition, some coal supply contracts have embedded volume options that the company uses when spot-market pricing is favorable compared to the contract price. In 2003, these coal strategies resulted in [redacted] to Tampa Electric's customers.

Q. What is the basis for your request to recover the commodity and transaction costs described above?

A. The Commission, in Order No. PSC-02-1484-FOF-EI, authorized the utility to

> . . .charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions for natural gas, residual oil, and purchased power contracts tied to the price of natural gas.
>
> Order, at page 5, paragraph 3.

Q. Are you requesting recovery of incremental hedging O&M costs?

A. Yes, Tampa Electric requests recovery of $108,746 that the company incurred as incremental O&M expenses. The Commission, in Order No. PSC-02-1484-FOF-EI, authorized the utility to

> . . .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.

Order, at page 6, paragraph 4

Tampa Electric's base year expenses, actual 2003 expenses and the resulting incremental expenses are shown in my exhibit (JTW-1). Tampa Electric established its base year expenses according to the portion of the employee's time and related costs for hedging in 2001 and then calculated its 2003 costs in the same manner. The recoverable amount is the increment, as shown in my exhibit (JTW-1).

Q. Does this conclude your testimony?

A. Yes it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
FILED: 9/9/04

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOANN T. WEHLE

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

A. My name is Joann T. Wehle. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Wholesale Marketing & Fuels.

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

A. I received a Bachelor of Business Administration Degree in Accounting in 1985 from St. Mary's College in Notre Dame, Indiana. I am a CPA in the State of Florida and worked in several accounting positions prior to joining Tampa Electric. I began my career with Tampa Electric in 1990 as an auditor in the Audit Services Department. I became Senior Contracts Administrator, Fuels in 1995. In 1999, I was promoted to Director, Audit Services and subsequently rejoined the Fuels Department as Director in April 2001. I became Director, Wholesale Marketing and

Fuels in August 2003. I am responsible for managing Tampa Electric's wholesale energy marketing and fuel-related activities.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to report to the Florida Public Service Commission ("Commission") the 2003 actual costs of Tampa Electric's affiliated coal transportation transactions compared to the benchmark prices calculated in accordance with Order No. 20298. My report will show that the 2003 prices paid by Tampa Electric to its affiliated company, TECO Transport, are reasonable and prudent. In addition, I will discuss the change in Tampa Electric's fuel mix, the company's natural gas strategies, fuel price forecasts, and potential impacts of the high and low fuel forecasts. Finally, I will address steps Tampa Electric has taken to manage fuel prices and supply volatility and describe projected hedging activities and incremental operations and maintenance (O&M) costs for these activities.

Q. Have you previously filed testimony before this Commission?

A. Yes. I filed testimony before this Commission in the predecessors to this docket since 2001 and in Docket No. 011605-EI. I also testified before this Commission in Docket Nos. 030001-EI and 031033-EI. My testimony in these dockets described the appropriateness and prudence of Tampa Electric's fuel procurement activities, fuel supply risk management, fuel price volatility hedging activities, and waterborne coal transportation costs.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes. Exhibit No. ___ (JTW-2), containing two documents, was prepared under my direction and supervision. Document No. 1 is furnished in support of the waterborne transportation benchmark application, and Document No. 2 describes the calculation of the company's incremental O&M hedging costs.

Coal Transportation Costs

Q. Were Tampa Electric's actual affiliated coal transportation prices for 2003 at or below the transportation benchmark established in Docket No. 870001-EI-A, Order No. 20298?

A. Yes. As shown on page 2 of Document No. 1 of my exhibit, the affiliated coal transportation prices for 2003 were at or below the appropriate benchmark calculations as directed by Order No. 20298 of this Commission. Accordingly, it is appropriate for Tampa Electric to recover its transportation expenses included in the Fuel and Purchased Power Cost Recovery Clause for 2003 coal transportation.

Q. What coal transportation rates are reflected in Tampa Electric's 2005 projected costs?

A. Tampa Electric utilized the waterborne coal transportation rates of the contract that took effect on January 1, 2004.

2005 Fuel Mix and Procurement Strategies

Q. Please describe any changes in the types and amounts of fuel that will be used by Tampa Electric's generating stations in 2005.

A. In 2004, Tampa Electric completed its transition from burning predominantly coal to utilizing a mix of natural gas and coal. As a result of the repowering of Gannon Station, Tampa Electric's reliance on natural gas has increased from three percent in 2002 to 39 percent of projected natural gas-fired generation in 2004. In 2005, natural gas-fired and coal-fired generation are expected to be 41 percent and 58 percent of total generation, respectively.

Q. How have Tampa Electric's activities and strategies related to natural gas procurement and forecasting changed now that natural gas-fired H. L. Culbreath Bayside Station ("Bayside Station") has successfully entered commercial service?

A. Tampa Electric continues to use a portfolio approach to natural gas procurement. The company's portfolio is comprised of long-term and spot resources to secure needed supply and maintain the ability to take advantage of favorable gas price movements. However, as the company's fuel mix has changed to incorporate more substantial volumes of natural gas, its focus on the natural gas market has increased as part of daily activities. Tampa Electric has increased the number of counterparties it can trade with for both physical gas and financial hedging products to provide flexibility in the procurement strategy.

Q. Please describe Tampa Electric's hedging plan.

A. Tampa Electric has continued to refine its hedging plan and strategies. Based on experience gained through the addition of Bayside Station, the company updated and enhanced the risk management plan, which was recently presented and approved by the company's Risk Authorizing Committee. Additionally, Tampa Electric implemented a risk management software program that improved the internal controls surrounding risk management activities by providing more detailed and timely reporting of hedging activities. The company's fuel procurement staff also reviewed industry information services from respected forecasting companies and selected the services of PIRA Energy Consulting to assist with forecasting fuel and energy market conditions. All of these activities have enhanced the company's tools and strategies with a focus on the natural gas market.

Q. How does Tampa Electric arrange for natural gas to be delivered to its units?

A. Tampa Electric has a contract for firm natural gas transportation. Additionally, the company evaluates the market and expected unit operations and attempts to sell any unused natural gas transportation capacity on a daily basis, and the resulting savings are flowed back to customers.

Q. What is Tampa Electric's coal procurement strategy?

A. Tampa Electric's two coal-fired plants are Big Bend Station and Polk Station. Big Bend Station is a fully scrubbed plant whose design fuel is high sulfur Illinois Basin coal, and Polk Station is an integrated gasification combined cycle plant that is currently burning a mix of Illinois Basin coal, petroleum coke, and lower sulfur coal. The plants have varying operations and environmental restrictions and require fuel with custom quality characteristics such as sulfur content, BTU/lb, ash fusion temperature and chlorine content. Since coal is not a homogenous product, fuel selection is based on these unique factors and price, availability, and creditworthiness of the supplier.

Tampa Electric maintains a portfolio of bi-lateral, long-, medium-, and short-term contracts for coal supply. This allows the company to maintain stable supply sources while providing flexibility to take advantage of favorable spot market opportunities. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the operating stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations help in market monitoring and in shaping the company's coal procurement strategy to reflect current market conditions.

Q. Has Tampa Electric entered into fuel supply transactions for 2004 and 2005 delivery?

A. Yes, it has. To mitigate price volatility and ensure reliability of supply, Tampa Electric has purchased the majority of its expected coal needs for both years through bilateral agreements with coal suppliers. Tampa Electric has also entered into contracts for a portion of the company's expected natural gas needs for the winter of 2004 to 2005 and expects to contract for the remainder of its supply needs within the next two months.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes. Tampa Electric diligently manages its mix of long-, intermediate-, and short-term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company monitors and adjusts fuel volumes it takes within contractually allowed maximum and minimum amounts in accordance with the price of fuel available on the spot market to take advantage of the lowest available fuel prices. The company's fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Projected 2005 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including PIRA Energy Consulting, Hill & Associates, the Energy Information Administration, the New York Mercantile Exchange ("NYMEX") and other energy consultants. Futures prices for energy commodities, as traded on the NYMEX, are the primary driver of the natural gas and No. 2 oil price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and quality adjustments. The transportation and quality adjustments are specific to the power plants to which the fuel will be delivered and the locations from which it is transported.

Coal prices and coal transportation prices are projected using information from industry-recognized consultants and are specific to the particular quality and location of coal utilized by Tampa Electric's Big Bend Station and Polk Unit 1. Final as-burned prices are derived by adjusting for expected transportation costs, as well as adjusting for costs associated with creating coal blends.

Q. How do the 2005 projected fuel prices compare to the fuel prices projected for 2004?

A. Projected fuel prices for 2005 have increased for all commodities. Tampa Electric began to see some increases in late 2003, but did not experience dramatic increases until 2004. The global economy and the increasing industrialization of countries like China have affected the price of natural resources such as natural gas, oil, and coal to a large degree. In addition, the transportation of these resources has been affected. The demand for these commodities and others, such as steel, has continued to exert upward pressure on these prices. Crude oil prices have seen unprecedented high pricing recently due to factors such as the turmoil in the Middle East and issues related to the Russian oil market.

Natural gas prices have increased 16 percent since the 2004 projection was prepared. The market drivers of this increase are the economic recovery for industries that are dependent on natural gas use, lower hydroelectric power output from the West, increased heating demand from the most recent winter and declining natural gas production in North America.

Coal prices are correlated with the prices of the other fuels since coal mining utilizes petroleum products, steel, and lumber in its production processes. Therefore, coal prices have also increased. In addition, more US domestic coal is being exported because of higher demand in Europe and Asia. For all of these reasons, Tampa Electric expects the higher prices to continue for all fuels through 2005.

Q. Did Tampa Electric consider the impact of higher than expected or lower than expected natural gas prices?

A. Yes. After reviewing the historical volatility in NYMEX pricing and the implied volatility in natural gas options, Tampa Electric has determined that actual prices in 2005 could be higher or lower than the base forecast by as much as 35 percent. Major fundamental or technical changes, such as abnormal weather, political instability or production shortages, will also dramatically affect price volatility. In the event of a significant natural gas price increase, the company evaluates potential lower cost alternatives.

Hedging Transactions and Related Expenses

Q. Given the volatility of the natural gas commodity market, has Tampa Electric entered into financial hedging transactions in 2004 to mitigate the price volatility of natural gas?

A. Yes. To protect customers from price risk, Tampa Electric purchased over-the-counter natural gas swaps and collars during 2004. A swap is a financial derivative that provides a "fixed for floating" position. The buyer (Tampa Electric) pays a fixed price for the natural gas, which has a floating value until cash settlement at the end of the month. The swaps allowed Tampa Electric to lock in known natural gas prices and avoid upward price volatility. The transaction costs of swaps are embedded in the price of the commodity.

Collars are combinations of call options (caps) and put options (floors) that collar prices within a certain range. With a collar, the company knows that its future prices will remain within the predetermined boundaries established by the call and put options.

Q. Will Tampa Electric use financial hedging to mitigate the price volatility of natural gas purchases in 2005?

A. Yes. Swaps are one of the hedging instruments Tampa Electric plans to use during 2005. Other instruments that Tampa Electric may use in 2005 are futures, options and collars.

Q. Does Tampa Electric anticipate incurring incremental O&M expenses related to initiating or maintaining its non-speculative financial hedging program in 2005?

A. Yes. In Order No. PSC-02-1484-FOF-EI, issued October 30, 2003, the Commission authorized the recovery of prudently-incurred incremental O&M expenses 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. Tampa Electric expects its 2005 total incremental hedging O&M cost to be $111,116. These incremental costs are itemized in Document No. 2 of my exhibit. The company purchased and implemented a software system to more efficiently track, monitor and evaluate hedging transactions in 2004. The annual license fee for this software system is included in the calculation of 2005 incremental costs.

Q. What is Tampa Electric's appropriate base O&M expense level used to calculate incremental hedging O&M expenses?

A. Tampa Electric's base level of hedging O&M expenses of $169,153 reflects the company's actual 2001 costs prior to its implementation of a prudent financial hedging program in 2002. The base level costs were audited by the Commission Staff in Audit No. 02-340-2-1, in Docket No. 030001-EI. Tampa Electric's expected 2005 incremental hedging O&M expenses shown in Document No. 2

of my exhibit are calculated using this audited base level.

Q. Were Tampa Electric's efforts through July 31, 2004 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the risk management plan filed with this Commission, which was approved by the company's Risk Authorizing Committee.

Q. Does this conclude your testimony?

A. Yes, it does.

CHAIRMAN BAEZ: What else do we have to take care of before we put Mr. Portuondo on?

MS. VINING: I believe we could move on now to the issues that are stipulated.

CHAIRMAN BAEZ: Okay. Can you run those down for us? They are quite a few.

MS. VINING: Sure. I would note first for the record that all of Gulf and FPUC's issues have proposed stipulations and, in fact, they were excused from the hearing.

CHAIRMAN BAEZ: You want us to take those -- would you identify them, or do we need to take those up separately or --

MS. VINING: No. I think we can take those in an aggregate. For FPUC we would recommend approval of the positions noted for them for Issues 1 through 9.

CHAIRMAN BAEZ: Commissioners, a motion? That would be approving the issues, the positions in Issues 1 through 9 as submitted by FPUC.

COMMISSIONER DEASON: Move approval.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Okay. Go ahead now. Gulf?

MS. VINING: And for Gulf Power Company we would recommend approval of the positions for Gulf in Issues 1 through 11, 18, 19, 22A, 22B, 22C and 24 through 29.

CHAIRMAN BAEZ: And that would be the balance of Gulf's issues.

MS. VINING: That would be correct.

CHAIRMAN BAEZ: Commissioners, is there a motion?

COMMISSIONER DEASON: Move approval.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor,say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, Commissioners.

Now, Ms. Vining, which -- now we have to take them --

MS. VINING: Yes. The next thing that I would like to have addressed is Issue 31A, which is a company-specific issue for Florida Power & Light in the capacity clause.

Each of the Commissioners should have staff's position on this as well as a proposed resolution of issue on the matter. And I guess as a preliminary matter, I would ask that that be marked as an exhibit.

CHAIRMAN BAEZ: And that would put us at Exhibit --

MS. VINING: It should be, I believe, Exhibit 59, if we're, you know, in line with the comprehensive stipulated exhibit list.

(Exhibit 59 marked for identification.)

CHAIRMAN BAEZ: That's correct. And that is stipulated language, Issue 31A

MS. VINING: Yes. On this issue staff has reviewed the proposed stipulation between FPL and OPC to resolve the issue concerning certain costs associated with the NRC's design basis threat order. Based on this review and with the anticipation that FPL's nuclear decommissioning accrual will actually decrease by at least $10 million, it appears that the immediate deferral and subsequent amortization of $38.3 million of design basis threat costs will result in benefits to the ratepayers. Therefore, staff recommends that the Commission approve the stipulation that resolves Issue 31A. And I would note that the stipulation is attached to staff's position on this issue.

CHAIRMAN BAEZ: Commissioners, any questions at this point?

COMMISSIONER DEASON: Yes, I have a question.

CHAIRMAN BAEZ: Commissioner Deason.

COMMISSIONER DEASON: The first year adjustment to the deferred debit, that being the amount of the reduction in the nuclear decommissioning accrual, that is an amount that the Commission will determine based upon the filing of the decommissioning study; is that correct?

MR. SLEMKEWICZ: That's correct.

COMMISSIONER DEASON: And it should be a

straightforward amount, and whatever that amount is, Florida Power & Light agrees to reduce the deferred debit by that amount?

MR. SLEMKEWICZ: That's correct.

COMMISSIONER DEASON: Okay. And we do not anticipate there to be any question as to what that amount is. I'm just -- from past experience, sometimes we think things are very clear, and then when we get to a making an adjustment sometimes issues arise. I just want to make sure that this is something that's not going to be subject to future litigation as to that one amount.

MR. SLEMKEWICZ: Right. It's the difference between the current accrual and what the new accrual will be based on the new study.

COMMISSIONER DEASON: And when will that study be filed?

MR. SLEMKEWICZ: I'm not sure. Sometime this spring, I believe. And we expect it to, you know, decrease because of the, you know, life extension of the units.

COMMISSIONER DEASON: Now I'm not trying to throw a wrench into the works, but the question is what if there's an increase in the deferral? There would not be an increase to the deferred debit; correct?

MR. SLEMKEWICZ: That's correct.

COMMISSIONER DEASON: Just it works in one direction nly.

MR. SLEMKEWICZ: That's correct.

COMMISSIONER DEASON: And there's only a one-year djustment because there -- does it coincide with the xpiration of the earnings and rate agreement?

MR. SLEMKEWICZ: That's correct. It ends in 2005. nd so this would take care of that one year where there would ot be a change in base rates.

COMMISSIONER DEASON: And then the Commission, if here is a reduction in the nuclear decommissioning accrual, hat would be an ongoing reduction until the next study is iled, and the Commission would have the discretion to address hat in whatever manner in the future.

MR. SLEMKEWICZ: That's correct.

COMMISSIONER DEASON: Is there any disagreement etween the parties with the answers that staff has just given?

MS. CHRISTENSEN: No. That's our understanding.

COMMISSIONER DEASON: Okay. Mr. Butler?

MR. BUTLER: No, no disagreement.

COMMISSIONER DEASON: No disagreement. Okay.

CHAIRMAN BAEZ: Commissioners, question or motion?

COMMISSIONER DEASON: I can move approval of the stipulation between Florida Power & Light and OPC.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, Commissioners.

Now that disposes of 31A.

MS. VINING: Yes.

CHAIRMAN BAEZ: All right. Moving right along. We're on Issue 1, or how do you want, how do you want to do this?

MS. VINING: What might be useful is since that was the last remaining company-specific issue for the capacity clause issues --

CHAIRMAN BAEZ: Right.

MS. VINING: -- we could address those issues at this time.

CHAIRMAN BAEZ: Okay.

MS. VINING: And then once that -- those are, those are agreed to, then we could excuse Ms. Dubin.

CHAIRMAN BAEZ: Very well. And I'm showing 25, 26, 27 and 29, is that --

MS. VINING: Well, actually starting with 24.

CHAIRMAN BAEZ: Okay. 24 through 29; is that correct?

MS. VINING: Correct. Well, I'm sorry. Actually 30A and 33A because those are company-specific issues for the capacity clause as well. But that doesn't affect Ms. Dubin.

CHAIRMAN BAEZ: Very well. But we can take them all up?

MS. VINING: That would make sense to me.

CHAIRMAN BAEZ: Okay.

COMMISSIONER DEASON: Mr. Chairman, I move approval of those issues.

CHAIRMAN BAEZ: There's a motion for approval of Issues 24, 25, 26, 27, 28, 29, 30A and 33A. Is there a second?

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: A motion and a second. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, Commissioners.

Ms. Vining.

MS. VINING: With that, I believe that Ms. Dubin can be excused at this time.

CHAIRMAN BAEZ: And the Chair excuses Witness Dubin.

MR. BUTLER: I would move the admission of her testimony into the record. I think we didn't do that before.

CHAIRMAN BAEZ: I'm sorry?

MR. BUTLER: I said, I'm sorry, I think we didn't do that for her before.

CHAIRMAN BAEZ: We haven't done that before. Without -- before she gets excused; right? Without objection, show the testimony, prefiled testimony of Witness Korel Dubin entered into the record as though read. And then her exhibits are, have already been previously marked as part of the comprehensive exhibit.

MR. BUTLER: Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 040001-EI

FEBRUARY 23, 2004

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 or the Company) 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 2003 through December 2003. The Net True-Up for the FCR is an over-recovery, including interest, of $41,808,676. The Net True-Up for the CCR is an under-recovery, including interest, of $7,050,083. I am requesting Commission approval to include this FCR true-up over-recovery of $41,808,676 in the calculation of the FCR factor for the period January 2005 through December 2005. And, I am requesting Commission approval to include this CCR true-up under-recovery of $7,050,083 in the calculation of the CCR factor for the period January 2005 through December 2005.

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 2003 through December 2003 period have been filed monthly with the Commission and served on all parties. Those schedules are incorporated herein by reference.

Q. What is the source of the data that you will present through 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 the Company's business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by the 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 2003 through December 2003, an over-recovery of $41,808,676. 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 2003 through December 2003 of $302,921,183 is shown on line 1. The estimated/actual End-of-Period under-recovery for the same period of $344,729,859 is shown on line 2. This amount was included in the calculation of the FCR factor for the period January 2004 through December 2004. Line 1 less line 2 results in the Net True-Up for the period January 2003 through December 2003 shown on line 3, an over-recovery of $41,808,676.

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 2003 through December 2003.

Q. Describe the variance in fuel costs?

A. The final over-recovery of $41,808,676 for the period January 2003 through December 2003 is due primarily to a $25.7 million (0.7%) decrease in Jurisdictional Total Fuel Costs and Net Power Transactions (Appendix I, page 6, line C6) and a $16.1 million (0.5%) increase in Jurisdictional Fuel Revenues (Appendix I, page 6, line C3).

The $25.7 million variance in Jurisdictional Fuel Costs and Net Power Transactions is due primarily to a $71.5 million (2.3%) decrease in the Fuel Cost of System Net Generation, a $4.7 million (36.2%) increase in Gains from Off-System Sales, and a $2.9 million (2.0%) decrease in Energy Payments to Qualifying Facilities, offset by a $6.2 million (7.9%) variance in the Fuel Cost of Power Sold, an $18.8 million (7.4%) increase in Fuel Cost of Purchased Power, and a $34.3 million (45.7%) increase in the Energy Cost of Economy Purchases.

As shown on the December 2003 A3 schedule, the $71.5 million (2.3%) decrease in the Fuel Cost of System Net Generation is primarily due to $114 million (5.7%) lower than projected natural gas cost offset by $39 million (4.5%) greater than projected heavy oil cost. The natural gas price averaged $6.24 per MMbtu, $0.28 per MMbtu (4.3%) lower than projected. Additionally, 4,376,819 fewer MMbtu's (1.4%) of natural gas were used during the period than projected. Heavy oil averaged $4.46 per MMbtu,

$0.04 per MMbtu (0.9%) higher than projected. Additionally, 7,133,992 more MMbtu's (3.6%) of heavy oil were used during the period than projected.

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

A. As shown on Appendix I, page 6, line C3, actual jurisdictional Fuel Cost Recovery revenues, net of revenue taxes, were $16.1 million (0.5%) higher than the estimated/actual projection. This increase was due to higher than projected jurisdictional sales, which were 648,039,165 kWh (0.7%) 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) to offset incremental fuel used to generate these kWh sales.

Q. What is the appropriate final 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 year 2004, the three year average threshold consists of actual gains for 2001, 2002, and 2003 (see below) resulting in a three year average threshold of $15,133,577:

2001	$17,846,596
2002	$9,726,487
2003	$17,827,648
Average threshold	$15,133,577

Gains on sales in 2004 are to be measured against this three year average threshold.

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 2003 through December 2003, an under-recovery of $7,050,083, which I am requesting to be included in the calculation of the CCR factors for the January 2005 through December 2005 period.

The actual End-of-Period over-recovery for the period January 2003 through December 2003 of $8,998,342 (shown on line 1) less the estimated/actual

End-of-Period over-recovery for the same period of $16,048,425, (shown on line 2) results in the Net True-Up under-recovery for the period January 2003 through December 2003 (shown on line 3) of $7,050,083.

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 2003 through December 2003. The End of-Period true-up shown on page 5, line 17 plus line 18 is an over-recovery of $8,998,342.

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 2003 through December 2003.

Q. What was the variance in net capacity charges?

A. As shown on line 9, actual net capacity charges on a Total Company basis were approximately $8.4 million (1.2%) higher than the estimated/actual projection. This variance was primarily due to $7.5 million (4.3%) higher than projected Payments to Non-Cogenerators caused by higher than estimated payments for UPS. Additionally, Short Term Capacity Payments were $1.2 million (1.3%) higher than projected, Payments to Cogenerators were $1.0 million (0.3%) higher than projected, and Transmission Revenues from Capacity Sales were $0.3 million (4.9%) lower than projected. These increases were somewhat offset by $1.0 million (9.2%) lower than projected Incremental Power Plant Security Costs and $0.6 million (6.6%) lower than projected expenses for Transmission of Electricity by Others.

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

A. As shown on line 14, actual Capacity Cost Recovery revenues, net of revenue taxes, were $1.3 million (0.2%) higher than the estimated/actual projection. This increase was due to higher than projected jurisdictional sales, which were 648,039,165 kWh (0.7%) 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. 040001-EI

August 10, 2004

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 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 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 2004 through June 2004 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 a comparison when calculating the FCR and CCR true-ups that are presented in your testimony.**

A. The FCR and CCR true-up calculation compares estimated/actual data consisting of actuals for January through June 2004 and revised estimates for July through December 2004, with the original estimates for January through December 2004 filed on September 12, 2003.

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 2004.

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 estimated/actual true-up amount for the period January 2004 through December 2004 is an under-recovery, including interest, of $182,196,299 (Appendix I, Page

3, Column 13, Line C7 plus C8).

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 2004 through June 2004, columns (1) through (6) reflects the actual results of operations and the data for July 2004 through December 2004; 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 predecessors to 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 original projections for the January 2004 through December 2004 period is provided in Appendix I, Page 4. FPL's original filing dated September 12, 2003 Jurisdictional Projected Total Fuel and Net Power Transactions to be $3.364 billion for January through December 2004 (See Appendix I, page 4, Column 2, Line C6). The estimated/actual Jurisdictional Total Fuel Cost and Net Power Transactions are now projected to be $3.522 billion for the period January through December 2004 (Actual data for January through June 2004 and revised estimates for July through December 2004) (See Appendix I, Page 4, Column 1, Line C6). Therefore, Jurisdictional Total Fuel Cost and Net Power Transactions are $158 million higher than originally projected. (See Appendix I, Page 4, Column 3, Line C6).

Jurisdictional Fuel Revenues for 2004 are $22.3 million lower than originally projected (Appendix I, Page 4, Column 3, Line C3). The $158 million of higher costs plus the $22.3 million of lower revenues, plus interest, result in the $182.2 million under-recovery.

This $182.2 million estimated/actual under-recovery net of the final over-recovery of $41.8 million for the period ending December 2003 filed on February 23, 2004 results in a net $140.4 million under-recovery to be carried forward to the 2005 FCR 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 $158 million or an 4.7% increase from projections.

This variance is mainly due to:

- A $242.3 million or 8.2% 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 $78.2 million (3.8%) higher than the original filing. The unit cost of natural gas in the estimated/actual period is $6.53 per MMBTU or $.63 (10.7%) higher than the $5.90 per MMBTU included in the original filing. Residual oil costs are currently projected to be $156.3 million (22.7%) higher than the original filing. The unit cost of residual oil in the estimated/actual period is $4.50 per MMBTU or $0.30 (7.1%) higher than the $4.20 per MMBTU included in the original filing.
- A $2 million or 4% increase in the Energy Cost of Economy Purchases due to higher than projected unit cost for economy purchases.

Offset by:

- A $62.7 million or 116.3% increase in Fuel Cost of Power Sold, which is primarily due to selling 85.1% more MWh's than projected at a 16.8% higher than projected unit cost. Additionally, gains from Off-System Sales are $9.9 million or 141.1% higher than projected.

- A $13 million or 4.5% decrease in Fuel Cost of Purchased Power due to 2% less than projected purchases at a slightly lower cost.

Q. What is the appropriate estimated benchmark level for calendar year 2005 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 2005, the three year average threshold consists of actual gains for 2002, 2003, and January through June 2004, and estimates for July through December 2004 (see below). Gains on sales in 2005 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 2005) to include all actual data for the year 2004.

2002	$ 9,726,487
2003	$13,091,111
2004	$16,992,686
Average threshold	$13,270,095

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. Appendix II, Pages 2 and 3 show the calculation of the CCR Estimated/Actual True-up amount. The calculation of the Estimated/Actual True-up for the period January 2004 through December 2004 is an under-recovery of $73,892,873 including interest (Appendix II, Page 3, Column 13, Lines 17 plus 18).

Q. Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes it is.

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 2004 reflects actual data and the data for July through December 2004 is based on updated estimates) compared to the original projections for the January 2004 through December 2004 period.

Q. What is the variance related to capacity charges?

A. As shown in Appendix II, Page 4, Column 3, Line 12, the variance related to capacity charges is a $74.7 million (12.4%) increase. The primary reasons for this variance is a $12.3 million increase in payments to non-cogenerators, a $16.6 million increase in short-term capacity payments, an $8.8 million increase in payments to cogenerators, a $2.2 million increase in Transmission of Electricity by Others, and a $38.8 million increase in Incremental Power Plant Security Costs. These amounts are slightly offset by a $3.1 million increase in Transmission Revenues from Capacity Sales.

The $38.8 million increase in Incremental Power Plant Security Costs is primarily a result of the expanded scope of activities needed to comply with the Nuclear Regulatory Commission (NRC) Design Basis Threat Order EA-03-086. FPL had originally projected $2.05 million in its September 13, 2003 filing for compliance with the DBT Order. FPL's current projection of the cost of complying with that order is $40.36 million. The reasons for this increase are addressed in the testimony of FPL witness, John Hartzog. The $12.3 million increase in payments to non-cogenerators is primarily due to higher than originally projected payments to Southern Company and SJRPP. The $16.6 million increase in short-term capacity payments is primarily due to higher than estimated short-term purchases. FPL entered into several short-term economic capacity transactions that were not included in its original projections for 2004. The $8.8 million increase in payments to cogenerators is due to higher than originally projected payments to ICL and Cedar Bay.

Additionally, Page 4, Column 3, Line 15, Capacity Cost Recovery revenues, net of revenue taxes, are $1.2 million higher than originally projected. The $74.7 million higher costs less the $1.2 million additional revenue, plus interest, results in an estimated/actual 2004 true-up amount of $73.9 million under-recovery (Appendix II, Page 4, Column 3, Lines 16 plus 17). This under-recovery of $73.9 million plus the final 2003 under-recovery of $7 million filed on February 23, 2004 results in an under-recovery of $80.9 million to be carried forward to the 2005 capacity factor.

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

A. Yes. 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.

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. 040001-EI

September 9, 2004

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 2005 through December 2005. 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, operational data as set forth in Commission Schedules E1 through E10, H1 and other exhibits filed in this proceeding, and data previously approved by the Commission. I am also providing projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten year projection of Florida Power & Light Company's annual generation mix and fuel prices.

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 80-81 included in Appendix II (KMD-5) and the entire Appendix III (KMD-6). 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 cost recovery (FCR) factor for which the Company requests approval?

A. 4.001¢ per kWh. Schedule EI, Page 3 of Appendix II shows the calculation of this twelve-month levelized FCR factor. Schedule E2, Pages 10 and 11 of Appendix II indicates the monthly fuel factors for January 2005 through December 2005 and also the twelve-month levelized FCR factor for the period.

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

A. Yes. Schedule E1-D, Page 6 of Appendix II, provides a twelve-month levelized FCR factor of 4.246¢ per kWh on-peak and 3.892¢ 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 FCR factor for the January 2005 through December 2005 period?

A. FPL is requesting to include a net true-up under-recovery of $140,387,623 in the FCR factor for the January 2005 through December 2005 period. This $140,387,623 under-recovery represents the estimated/actual under-recovery for the period January 2004 through December 2004 of $182,196,299 that was filed with the Commission on August 10, 2004 plus the final true-up over-recovery of $41,808,676 that was filed on February 23, 2004 for the period January 2003 through December 2003.

Q. What adjustments are included in the calculation of the twelve-month levelized FCR 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 2005 factor is an under-recovery of $140,387,623. This amount divided by the projected retail sales of 103,009,994 MWh for January 2005 through December 2005 results in an increase of .1363¢ per kWh before applicable revenue taxes. The Generating Performance Incentive Factor (GPIF) Testimony of FPL Witness Pam Sonnelitter, filed on April 1, 2004, calculated a reward of $6,615,282 for the period ending December 2003 which is being applied to the January 2005 through December 2005 period. This $6,615,282 divided by the projected retail sales of 103,009,994 MWh during the projected period results in an increase of .0064¢ per kWh, as shown on line 33 of Schedule E1, Page 3 of Appendix II.

Q. **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." Has FPL included any additional costs in its factors for the period January 2005 through December 2005 consistent with the Hedging Resolution approved in Docket No. 011605-EI?

A. Yes. As stated in the testimony of FPL witness Gerard Yupp, FPL projects to incur $553,145 in incremental O&M expenses for FPL's expanded hedging program. The $553,145 is for three (3) employees who are dedicated full time to FPL's expanded hedging program and for computer license fees.

Since the entire $553,145 in O&M expenses are for FPL's expanded hedging program and none of those expenses were included in FPL's MFR filing in Docket No. 001148-EI, FPL has included $553,145 in projected incremental hedging expenses in its FCR calculations for the period January 2005 through December 2005. This amount is shown on line 3b of Schedule E1, page 3 of Appendix II.

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 2005 through

December 2005. Total Recoverable Capacity Payments amount to $689,014,560 (line 16) and include payments of $189,483,480 to non-cogenerators (line1), Short-term Capacity Payments of $71,226,940 (line 2), payments of $353,802,166 to cogenerators (line 3), and $4,718,484 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 4a) $35,856,342 of Okeelanta/Osceola Settlement payments (line 5b), $12,482,363 in Incremental Power Plant Security Costs (line 6), and $7,118,219 for Transmission of Electricity by Others (line 7). This amount is offset by $4,407,384 of Return Requirements on SJRPP Suspension Payments (line 4b), by Transmission Revenues from Capacity Sales of $7,026,600 (line 8), and $56,945,592 of jurisdictional capacity related payments included in base rates (line 12) less a net under-recovery of $80,942,956 (line 13). The net under-recovery of $80,942,956 includes the final under-recovery of $7,050,883 for the January 2003 through December 2003 period that was filed with the Commission on February 23, 2004, plus the estimated/actual under-recovery of $73,892,873 for the January 2004 through December 2004 period, which was filed with the Commission on August 10, 2004.

Q. Has FPL included a projection of its 2005 Incremental Power Plant Security Costs in calculating its Capacity Cost Recovery (CCR) Factors?

A. Yes. FPL has included $12,482,363 on Appendix III, page 3, Line 6 for projected 2005 Incremental Power Plant Security Costs in the calculation of its CCR Factors.

Of the total $12,482,363 for 2005 incremental power plant security costs, $10,838,199 is for nuclear power plant security, which is discussed in the testimony of FPL Witness John Hartzog. The remaining $1,644,163 of the total $12,482,363 is for fossil power plant security. This projection includes the costs of increased security measures for incremental fossil power plant security required by the Maritime Transportation Act, Security Coast Guard rule and/or recommendations from the Department of Homeland Security authorities. FPL is in the process of complying with these requirements and will continue implementing these measures into 2005. The measures include the cost of cameras/recorders and security guards.

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 CCR clause. On November 9, 2001, FPL filed a series of 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 this series of 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 FPL's 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 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 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 2005 through

December 2005. 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 2005?

A. The typical 1,000 Residential kWh bill is $90.35. This includes a base charge of $40.22, the fuel cost recovery charge from Schedule E1-E, Page 7 of Appendix II for a residential customer is $40.09, the Capacity Cost Recovery charge is $7.39, the Conservation charge is $1.48, the Environmental Cost Recovery charge is $0.25 and the Gross Receipts Tax is $0.92. A comparison of the current Residential (1,000 kWh) Bill and the 2005 projected Residential (1,000 kWh) Bill is presented in Schedule E10, Page 78 of Appendix II.

Q. Does this conclude your testimony.

A. Yes, it does.

CHAIRMAN BAEZ: Okay. Ms. Vining.

MS. VINING: I believe we can go to Issue 1 now.

CHAIRMAN BAEZ: Okay. Commissioners --

MS. VINING: I would note that since you've already done a, approved a universal stipulation for Gulf and FPUC, now staff would recommend approval of the positions listed for FPL and TECO.

CHAIRMAN BAEZ: On, on just Issue 1?

MS. VINING: Yes. Just on Issue 1.

CHAIRMAN BAEZ: Commissioners, a motion?

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, Commissioners.

Issue 2.

MS. VINING: Before we move on from Issue 1, I believe there's a correction that Progress Energy would like to make to their position.

CHAIRMAN BAEZ: Oh.

MS. DAVIS: I know we have a correction to Issue 2. I'm not sure we have a correction to Issue 1.

MS. VINING: I can propose it, if you guys can tell me if you agree.

COMMISSIONER DAVIDSON: I guess we moved reconsideration of Issue 1, so the --

MS. VINING: Well, no. The Progress Energy position wasn't part of the proposal, is my understanding.

CHAIRMAN BAEZ: It's not part, it's not part of the stipulation. It was only FP&L and TECO.

COMMISSIONER DAVIDSON: Okay.

MS. DAVIS: There's no change to our position.

MS. VINING: Okay. Okay. I thought we, I thought we had a change.

MS. DAVIS: Issue 2.

MS. VINING: Okay. I apologize then.

CHAIRMAN BAEZ: Issue 2.

MS. VINING: On Issue 2 we would recommend approval of the position listed for Florida Power & Light.

CHAIRMAN BAEZ: Commissioners, questions or a motion.

COMMISSIONER DEASON: Move approval.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Motion and a second to approve the Power & Light position on Issue 2. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, Commissioners.

Issue 3.

MS. DAVIS: Commissioner, for Issue 2 --

CHAIRMAN BAEZ: Ms. Davis, can you turn your mike on?

MS. DAVIS: Oh, sorry. For Issue 2 our position has changed. The correct number should be $17,490,748 overrecovery.

COMMISSIONER BRADLEY: Repeat that, please.

MS. DAVIS: $17,490,748.

CHAIRMAN BAEZ: I'm sorry. And that's still overrecovery?

MS. DAVIS: Yes, sir.

CHAIRMAN BAEZ: Okay. Issue -- we are on Issue 3?

MS. VINING: Yes.

CHAIRMAN BAEZ: Go ahead.

MS. VINING: For Issue 3 we would recommend approval of the position listed for FPL on Issue 3.

CHAIRMAN BAEZ: Commissioners, questions or a motion.

COMMISSIONER DEASON: Move approval.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

MS. DAVIS: Mr. Chairman, our position on Issue 3 has changed

CHAIRMAN BAEZ: Okay. Go ahead.

MS. DAVIS: In place of the number $84,589,752, the correct number should be $76,802,024. And in place of the number $163,747,022, the number should be $155,959,294.

CHAIRMAN BAEZ: Very well. Issue 4.

MS. VINING: For Issue 4 we would recommend approval of the positions listed for FPL, Progress Energy and TECO.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, Commissioners.

Issue 5.

MS. VINING: On Issue 5, we would recommend approval of the position listed for FPL under staff's position.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

MS. DAVIS: Mr. Chairman --

CHAIRMAN BAEZ: Ms. Davis.

MS. DAVIS: -- our position on Issue 5 has changed. In place of the number shown there, the correct number is $1,576,406,043.

CHAIRMAN BAEZ: Thank you, Ms. Davis.

Issue 6.

MS. VINING: For Issue 6, we would recommend approval of the position listed for Florida Power & Light.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, Commissioners.

MS. DAVIS: Mr. Chairman, our position on Issue 6 has changed. In place of the number shown of 3.932, the correct number is 3.912.

CHAIRMAN BAEZ: Thank you, Ms. Davis.

Issue 7.

MS. VINING: On Issue 7, staff would recommend approval of the positions listed for FPL, Progress Energy -- oh, no. Excuse me. Just, just for FPL. Oh, I'm sorry. I was getting ahead of myself. FPL, Progress Energy and TECO.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Issue 8.

MS. VINING: For Issue 8, staff would recommend approval for the position listed for FPL.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

MS. DAVIS: Commissioner, our position for Issue 8 has changed. It is shown on Page 17 of the prehearing order. The number for Group A, Transmission, should change from 3.859 to 3.840. The on-peak number should be 4.946. The off-peak number should be 3.368.

For Group B, Distribution Primary, the standard number is 3.879, the on-peak number is 4.996, the off-peak number is 3.402.

For Group C, Distribution Secondary, the first number is 3.918, the on-peak number is 5.046, the off-peak number is 3.436.

For Group D, Lighting Service, the number is 3.737.

CHAIRMAN BAEZ: Can you repeat that last number, Ms. Davis?

MS. DAVIS: 3.737.

CHAIRMAN BAEZ: Thank you. Issue 9.

MS. VINING: On Issue 9, we would recommend approval of the position listed.

CHAIRMAN BAEZ: Commissioners, a motion.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in avor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Issue 10.

MS. VINING: For Issue 10, we would recommend approval of the positions listed for FPL, Progress and TECO.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Issue 11.

MS. VINING: For Issue 11, staff would recommend approval for the positions listed for FPL, Progress and TECO.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Issue -- I have Issue 13A.

MS. VINING: Right. For that one, staff would recommend approval of the position listed.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, Commissioners.

Issue 13C.

MS. VINING: Staff would recommend approval of the position listed.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: 13E.

MS. VINING: For that one we would also recommend approval of the position listed.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: 17A.

MS. VINING: Staff would recommend approval of the position listed.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, Commissioners.

17B.

MS. VINING: Staff would recommend approval of the position listed.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: 17C.

MS. VINING: Staff would recommend approval of the position listed.

MS. KAUFMAN: Chairman Baez. I'm sorry.

CHAIRMAN BAEZ: Ms. Kaufman.

MS. KAUFMAN: This was just the issue I reserved my right to look at it next year.

CHAIRMAN BAEZ: Thank you for that clarification.

COMMISSIONER DEASON: So moved.

CHAIRMAN BAEZ: We have a motion on 17C. Is there a second?

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: All those in favor, say aye

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Next I have 17F. Is that correct? Yes

MS. VINING: Yeah. On that one, staff would recommend approval of the position listed.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Issue 18.

MS. VINING: For 18, staff would recommend approval of the positions listed in Attachment A to the prehearing order with regard to companies Progress Energy, Tampa Electric and FPL

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Issue 19.

MS. VINING: For Issue 19, staff would recommend approval of the positions listed in Attachment A with regard to utilities Florida Power & Light and Progress Energy Florida.

COMMISSIONER DEASON: So moved.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Moved and seconded. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, Commissioners. I think that does it for the proposed stipulations; is that correct?

MS. VINING: Correct.

CHAIRMAN BAEZ: All right. And I think we're at that point where we can take up witnesses, or you have one other --

MS. VINING: I have one other housecleaning matter.

CHAIRMAN BAEZ: Okay.

MS. VINING: The letter from Senator Bennett --

CHAIRMAN BAEZ: Yes.

MS. VINING: -- we have not marked that yet. I would suggest that it should be Exhibit Number 60.

CHAIRMAN BAEZ: My next number is 60. We'll show the letter from Senator Bennett dated November 5th, 2004, marked as Exhibit 60.

MS. VINING: At this time we'd request that it be moved into the record.

CHAIRMAN BAEZ: Without objection, show Exhibit 60 moved into the record.

(Exhibit 60 marked for identification and admitted into the record.)

CHAIRMAN BAEZ: And I think we're ready to swear witnesses. Will all the witnesses that are in the room please stand and raise your right hand.

(Witnesses collectively sworn.)

CHAIRMAN BAEZ: Thank you. You can be seated.

MS. KAUFMAN: Mr. Chairman --

CHAIRMAN BAEZ: Ms. Kaufman, thank you for waving because the voices, they come in and --

MS. KAUFMAN: I believe there's another preliminary matter, just, just so the record is clear. There is a motion pending by Florida Power & Light, a motion to compel, and there was a motion for protective order pending by FIPUG. And we've discussed it with Ms. Smith this morning and have agreed that their motion will be withdrawn as will ours.

And if, if Ms. Smith has anything to add, but I believe that is the understanding. There's no need for the Commission to reach a decision on that.

CHAIRMAN BAEZ: Now, Ms. Vining, can you, can you clear something up for me? There are some motions that the underlying discovery was withdrawn. This is not what Ms., what Ms. Kaufman is alluding to.

MS. VINING: No. Those are not the motions she's referring to.

CHAIRMAN BAEZ: Very well. Well, if the motion is withdrawn, is there anything that we need to do?

MS. VINING: No.

CHAIRMAN BAEZ: Okay. Thank you, Ms. Kaufman.

The first witness is Witness Portuondo; correct?

MR. BUTLER: Excuse me. Chairman Baez?

CHAIRMAN BAEZ: Yes.

MR. BUTLER: FPL would want to make an opening statement with respect to the testimony of Mr. Hartman and the subject of the UPS agreements. It seems like it would make sense to do that when we get to it, but I just want to make sure that we reserve the opportunity to do so at the appropriate time.

CHAIRMAN BAEZ: You, you can -- and let me, let me just -- hold on. I know Ms. Christensen is going to have something to say about that. Well, go ahead and say it now.

MS. CHRISTENSEN: I was just going to comment that we had opening statements or prepared short opening comments as well, and I don't know if you want to take opening statements just as a preliminary matter before witnesses or --

CHAIRMAN BAEZ: And you kind of anticipated my comment. I was going to go -- I mean, I appreciate that it would probably be more appropriate to do it as a witness is coming up because it really means the balance of, of the case. But I think at this point, you know, if there are, if there are other parties that need to make opening statements, maybe it's better if we take them all, get them into the record at this point.

And I'm not sure about the order, but I think since you're, you're sitting there way to the right --

MR. BUTLER: I'm happy to go now, if that's what you'd like.

CHAIRMAN BAEZ: If that's all right with you.

MR. BUTLER: Certainly. Okay. Good morning, Commissioners. FPL is asking you to review and approve in this proceeding three power purchase agreements between FPL and subsidiaries of Southern Company.

The agreements are intended to replace the energy and 930 megawatts of total capacity that FPL obtains through its current UPS agreement with the Southern Company. That agreement will expire on May 31, 2010. The new agreements will cover the period June 1, 2010, to December 31, 2015. They will provide FPL 165 megawatts of coal-fired capacity from Scherer Unit 3, with the remaining capacity coming from the gas-fired Harris Unit 1 and Franklin Unit 1.

FPL needs the Commission to review and approve the new UPS agreements in this proceeding because FPL has only a very narrow window of opportunity to terminate the agreements if they are not approved. That window can close as early as the first half of February 2005.

The new UPS agreements will represent a large financial commitment. FPL cannot justify making that commitment without knowing first that the Commission finds the agreements to be in the interest of FPL's customers.

FPL's Witness Tom Hartman will demonstrate that the new UPS agreements are indeed in the customers' interests. There are several key benefits to FPL and its customers that will result from the agreements.

First, FPL will maintain 165 megawatts of firm coal-fired capacity in its portfolio, with the opportunity to purchase additional coal by wire on an as-available basis and a right of first refusal for additional firm coal-fired capacity from the Miller and Scherer plants.

Second, FPL will retain 930 megawatts of firm transmission service in the SERC region, S-E-R-C, for the period 2010 through 2015, and will position itself to extend that service again in later years.

Third, the transmission access will allow FPL to procure energy and capacity from SERC when market terms are favorable, thus reducing power costs for FPL's customers.

Excuse me. Fourth, the transmission access also will enable FPL to obtain firm capacity and/or purchase market energy from outside Florida to enhance FPL's power supply reliability.

Fifth, the gas-fired capacity under the new UPS agreements will be served by a separate gas transmission network that is independent of those serving FPL's plants. This will provide a valuable increase in the diversity of fuel transportation for FPL's gas-fired resources, which will further enhance FPL's power supply reliability.

Finally, the UPS agreements are for a relatively short duration. Entering into them will allow FPL additional time over the next ten years to investigate the possibility of using non-gas technologies.

In contrast, without the new UPS agreements, FPL likely will have to make a long-term commitment to additional gas-fired capacity and, therefore, lose that flexibility.

These benefits are substantial and they will have long-lasting impacts. The Commission should approve the new UPS agreements in this proceeding so that FPL can lock in those benefits while it has the chance to do so.

There are three witnesses who have filed testimony opposing approval of the new UPS agreements. All three are closely allied with the merchant power industry; two are actually employees of merchant providers.

The merchant witnesses have covered their true interests with the thinnest of disguises here, but no one should be fooled as to their intentions. They want to keep open as many opportunities as possible for merchant sales in Florida, irrespective of whether this would be in the interest of FPL's customers. FPL respectfully asks the Commission to keep the true interests of these merchant witnesses in mind when considering their testimony.

The merchant, merchant witnesses all make essentially the same point in arguing against approval of the new UPS agreements. They assert that FPL should be required to conduct an RFP prior to seeking Commission approval for the agreements. Only by doing so, they assert, can the Commission assure itself that the new UPS agreements are in the customers' interests. But the merchant witnesses simply fail to make the case that conducting an RFP would make any positive difference here.

There is an extremely limited pool of resource alternatives that could provide benefits comparable to those available to FPL and its customers under the new UPS agreements. If the RFP did not require bids to include the benefits of the new agreements, the bids most likely would include few, if any, of those benefits. On the other hand, if the RFP did require the benefits of the new agreements, FPL doubts that anyone other than the Southern Company would be in a position to bid. There is no reason to believe that a Southern Company bid would be as good as, much less improve on, the negotiated deal reflected in the new UPS agreements.

Furthermore, in our -- excuse me -- an RFP is unnecessary because FPL has already done a thorough job of canvassing the market for relevant alternatives. FPL determined that the cost of power under the new UPS agreements is below the publicly available prices for other relevant contracts in the Southern Company territory.

FPL also sought indicative offers from existing merchant facilities that realistically might be able to supply alternative power. It received only one such offer, which was not as cost-effective as the new agreements.

FPL performed an RFP last year in connection with the Turkey Point Unit 5 need determination proceeding, so FPL also took the opportunity to evaluate the new agreements against the most relevant bid it received in response to that RFP. Again, the new UPS agreements were more cost-effective.

The only alternative that could compare favorably to the new agreements is an FPL self-build gas-fired unit. Looking only at the readily quantified cost, a self-build unit could be between $69 million and $93 million less expensive than the new UPS agreements. But if FPL were to build such a unit, it would forego all of the less quantifiable benefits I outlined earlier: 165 megawatts of coal-fired capacity, firm transmission service in the SERC region with attendant opportunities for economic purchases and reliability enhancement, increased diversity of natural gas transportation routes, and additional time to decide whether to make a long-term commitment to gas-fired capacity. FPL believes that those benefits clearly outweigh the quantified cost differential.

In summary, the new UPS agreements represent a good deal for FPL's customers. FPL needs the Commission's prompt review and approval in order to secure those benefits. FPL is confident that the evidence will provide you a solid basis for approving the agreements in this proceeding, and we ask that you do so. Thank you.

CHAIRMAN BAEZ: Thank you, Mr. Butler.

Mr. Beasley.

MR. BEASLEY: No, sir.

CHAIRMAN BAEZ: You're going to waive your opening statement.

Ms. Davis

MS. DAVIS: Yes, sir, we have a brief opening statement.

Commissioners, I believe the only issue remaining for us now relates to waterborne transportation costs for our coal purchases. As you may recall, last year you voted to continue the market proxy pricing system that had been in effect since 1992 through calendar year 2003, and then to end it effective 12/31/03. Subsequently you approved a settlement for calendar year 2004 in an RFP process from that point forward.

The issue that you will hear about today concerns the application of the market price proxy for 2003, the last year in which it is effective. We believe that the evidence will show that we correctly applied the proxy for all coal purchases in that year.

To refresh your memory, you may recall that last year when you discussed this, you established a proxy that related to -- was intended to provide compensation for all segments of the transportation trade, that is from the mine to the river, down the river to the terminal, then from the terminal across the Gulf of Mexico to Crystal River.

There are a subset of coal purchases that are made in New Orleans or in Mobile at the terminal. Remember, there's a price that you pay for the coal, the commodity price, and then a separate transportation proxy for the cost of transporting that coal.

For coal that's purchased in New Orleans, we believe that in a subset of those purchases there is an increment related to the cost of terminaling the coal in New Orleans that is included in the commodity price. Since we receive a comprehensive market price proxy that's intended to include that service, we felt it was necessary to back the trans-loading cost of the seller when we're the buyer out of the commodity cost. We believe that we correctly did that. And then we took the adjusted commodity price plus the market proxy for 2003 as the total cost that is passed on to customers.

We believe that Ms. Davis will convince you that this is the way the proxy was intended to work and that it was correctly applied for calendar year 2003. Thank you.

CHAIRMAN BAEZ: Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman. The other day I was having a conversation with a friend of mine, and he asked me how work was going and what I was working on, and I told him a little bit about, about this case. And his remark back to me, after I told him that FPL was seeking approval of these contracts that didn't take effect until 2010, was, he said, "It seems to me only outside of Hollywood could FPL and Southern create a perfect storm that would require this Commission to act right away." And I thought about that a little bit, and over the weekend I took the liberty of, of writing a little bit using that theme and have prepared an opening that references this perfect storm. I wanted to give you that by way of background so if I go through this, you're scratching your head going where is this perfect storm coming from?

This case involves a perfect storm that was created when two large corporate systems from the southeast, Florida Power & Light and the Southern Company, collided in contract negotiations. The eye of the storm revolves around an existing contract, the UPS agreement, which does not expire until the summer of 2010. However, this summer the parties struck a new deal.

The new deal adds two gas-fired Southern power plants to the mix, while dropping one coal-fired Southern unit entirely. It replaces 930 megawatts of coal-fired capacity with only 165 megawatts of coal-fired capacity, then tacks on nearly 800 megawatts of gas-fired capacity. The deal for which FPL seeks approval is one of the largest purchased power contracts this Commission has been ever -- has ever been asked to approve.

The perfect storm has created a sense of urgency complete with warnings that action must be taken now. FPL tried to get Southern to agree to let this Commission have a year to review the deal, but Southern's strength prevailed at the negotiating table. The PSC got a six-month review and approval time or else the deal could be off. Rather than use the agreed to six months, FPL is now asking the Commission to approve the deal now, a mere two months after FPL made its first filing describing the terms of the arrangement.

The forecasts associated with the perfect storm are unclear, however, as they are based on conditions that are likely to change, given that the eye is not due to strike until the summer of 2010. However, here is a long-range forecast about three of the issues you will hear testimony on.

FPL wants this Commission to recognize unquantifiable benefits which it itself has not been able to value or provide a dollar estimate for. The benefits FPL asks this Commission to accept tipping the scales in favor of contract approval are apparently not being capable -- are not capable of being measured by FP&L. FP&L says these contracts are not a case of measurement but of judgment. However, this Commission cannot must accept FPL's subjective judgment, but must make its own determination. FPL has failed to provide enough information about these benefits and cannot even rank the benefits in order of importance.

Second issue, market power issues looming in Washington may have an impact on the perfect storm deal. FPL acknowledges that Southern has made a filing at FERC in which it admits failing one of FERC's indicative tests of market power. A review of Southern market power is something the FERC is presently considering. The impacts of market power may be on the horizon in Tallahassee today as FPL admits that its real interest in contract negotiations was to retain its coal-fired generation under the UPS agreement. Well, FPL lost considerable ground on this point. As mentioned, it went from having 930 megawatts of coal-fired generation down to only 165 megawatts of coal-fired generation. And to get this, FPL had to agree to take 790 megawatts of gas-fired generation that it admits it did not want by itself. Southern's linking 165 megawatts of coal-fired generation to 790 megawatts of gas-fired generation is a questionable tie-in arrangement.

Third, other forecasters believe the perfect storm deal may not be good for ratepayers. FPL and this Commission should gather as much information as possible before moving forward and approving this deal. However, FPL never sought offers from Florida market providers. FPL never issued an RFP.

FPL never publicly indicated that it was interested in discussing this deal with others in the SERC market. FPL, with no expertise in transmission planning, unilaterally eliminated multiple potential suppliers in the SERC region due to concerns about transmission constraints. What FPL did do was make a few phone calls, and after those phone calls received only one indicative offer before they inked this deal with Southern.

Forecasters such as Mr. Churbuck and FIPUG suggest that market forces brought to bear by an RFP or other transparent public solicitation process can reduce the storm's impact or eliminate it altogether. Even FPL's own internal weatherman, it's self-build option, projects it could save ratepayers between $69 and $93 million.

In conclusion, the Commission should not approve the Southern/FPL deal at this time. Sufficient information has not been presented to justify its approval. The benefits espoused by FPL are less than certain and hinge on a number of things that may or may not happen in the future.

Issues of market power exist. Florida Power & Light candidly did not fully investigate other options before signing up with Southern.

The weather outside today is clear. The long-range forecast suggests that the perfect storm can be avoided and, quite frankly, should be. Thank you.

CHAIRMAN BAEZ: Thank you, Mr. Moyle. Ms.

Christensen.

MS. CHRISTENSEN: Good morning, Commissioners. Patricia Christensen on behalf of the Citizens of the State of Florida.

As you've heard from Ms. Davis, the Citizens have a few issues here today in this year's fuel proceeding, and these are first with Progress's charging of the proxy for trans-loading -- for transactions designated FOB Dixie barge. And the second issue we have is with Tampa Electric's GPIF targets for 2005.

We believe that the testimony will show today that Progress inappropriately charged the trans-loading portion of the proxy for contracts which were designated FOB Dixie Fuel barge.

In deposition, Progress Witness Davis testified that FOB Dixie barge means that the fuels delivered onto the Dixie barge, which is the oceangoing barge, Witness Davis admits that for those contracts designated FOB Dixie barge, the coal included the cost of the trans-loading activities. Witness Davis testified in deposition that the coal brought -- bought FOB Dixie barge had already been trans-loaded off the oceangoing vessel and was sitting on the ground at IMT. That is New Orleans.

She also testified in her supplemental testimony that she backed out the approximate amount of the trans-loading cost from the coal cost, and then Progress turned around and charged the customers the full trans-loading cost of the proxy. And we believe that that was inappropriate and we believe that the testimony will show that they should not have charged the proxy at all.

Since the trans-loading activities were already taken care of by the coal supplier, not Progress, and because Progress simply created a paper transaction reducing the coal price per ton a slight amount for trans-loading on its Commission report in order to justify charging the customer the higher trans-loading proxy per ton, we believe that the Commission should not allow them to have charged the full proxy or the proxy at all, and that the differential between what they backed out and the full charge, the full cost of the proxy should be credited back to the customers.

Our second issue is regarding Tampa Electric's GPIF targets for 2005. We believe that the evidence will show that Tampa Electric's 2005 targets for the GPIF should not be approved. We believe the evidence will show that the equivalent plant availability factor is the amount of time that the plant is available to serve the power needs of the company and that the higher the availability, the better. And that the heat rate, which is also part of the GPIF calculation, is the technical term regarding the operating efficiency of the plant and that the lower the heat rate, the better.

We believe that Witness Knapp's testimony, as, as he has testified in deposition, will show that the availability for the Big Bend coal plants, particularly those 1 through 3, has been declining for at least the last three years. We believe that testimony today will show, and he has admitted in deposition, that Tampa Electric did not meet its 2003 availability targets for Big Bend 1 through 3 and also 4 and was penalized in 2003. We believe that the testimony will show that the 2005 availability targets for the Big Bend is below the actual performance of the Big Bend in 2003. And we believe that he has acknowledged in his deposition and will acknowledge today that if the Big Bend plants meet the current 2005 availability targets for these plants, that the same performance which would have caused merely two years ago a penalty be incurred, a penalty to be incurred, would result in no penalty and possibly an award today if the 2005 targets are approved.

And we believe that in listening to all of the testimony that will be presented today, that the Commission will and should not accept the proposal to reward performance in 2005 that it deemed unacceptable in 2003, and that they will approve appropriate targets for 2005 minimally relating back to 2003.

So in summary, we believe that Progress inappropriately charged customers the trans-loading proxy for transactions designated FOB Dixie barge, resulting in customers being overcharged approximately $800,000 which should be returned to the customers, and we believe that Tampa Electric's GPIF targets for 2005 should not be approved because it has the potential to award availability performance that was subject to penalties merely two years before, and that customers should -- and that the Commission, excuse me, should establish the same incentive awards for 2005 that were approved for 2003. Thank you.

CHAIRMAN BAEZ: Thank you, Ms. Christensen.

(Transcript continues in sequence with Volume 3.)

STATE OF FLORIDA)
CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, Official Commission Reporter, 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' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 17th DAY OF NOVEMBER, 2004

Linda Boles

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