BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080001-EI

In the Matter of

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

VOLUME 3

Pages 280 through 437

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN MATTHEW M. CARTER, II COMMISSIONER LISA POLAK EDGAR COMMISSIONER KATRINA J. McMURRIAN COMMISSIONER NANCY ARGENZIANO COMMISSIONER NATHAN A. SKOP
DATE:	Tuesday, November 4, 2008
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, CRR, RPR Official FPSC Reporter (850) 413-6734
APPEARANCES:	(As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.
44 through 46		403
47 through 48		316
49 through 50		284

PROCEEDINGS

* * * * *

(Transcript continues in sequence from Volume 2.)

CHAIRMAN CARTER: All right. With that, we are now on TECO. Thank you, sir. Good afternoon.

MR. BEASLEY: Good afternoon. How are you, sir?

Mr. Chairman, Tampa Electric has two witnesses, Ms. Wehle and Mr. Smith, who address issues that were on the list of stipulated issues that you approved earlier today. And unless there are any questions that you may have of them, I would suggest that their testimony be inserted into the record and their exhibits be admitted.

CHAIRMAN CARTER: Does staff have any questions of those witnesses?

MS. BENNETT: No questions of these witnesses.

CHAIRMAN CARTER: Commissioners? Okay. Then the prefiled testimony of the witnesses will be entered into the record as though read. Now the exhibits.

MR. BEASLEY: Yes, sir. They are.

CHAIRMAN CARTER: It would be 44 -- wait a minute. You tell me what the numbers are.

MR. BEASLEY: They are 49 and 50.

CHAIRMAN CARTER: 49 and 50?

MR. BEASLEY: Yes, sir.

CHAIRMAN CARTER: Any objections? Without objection, show it done.

(Exhibits 49 and 50 admitted into the record.)

Oh, Mr. McWhirter.

MR. McWHIRTER: Mr. Chairman, Mr. -- I have questions for Mr. Aldazabal.

CHAIRMAN CARTER: Okay.

MR. McWHIRTER: And one of the questions may, he may want to refer to Mr. Smith.

CHAIRMAN CARTER: Hang on a second. Hang on a second.

MR. McWHIRTER: And so if you don't excuse Mr. Smith, that would be okay, but I may not have to ask him any questions.

CHAIRMAN CARTER: Let's just deal with Ms. Wehle, Wehle.

MR. BEASLEY: Wehle.

CHAIRMAN CARTER: Wehle. See, I was in the same neighborhood. Was it the same country? Let's deal with Ms. Wehle first then. And that would be on Exhibits 49 and 50. Any questions, any concerns from any of the parties on Ms. Wehle?

MR. BURGESS: No.

CHAIRMAN CARTER: Without objection, show it done. Also this witness may be excused. Any objections of any of the parties? Okay. Thank you.

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 2007 results 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.

Q. What is the source of the data you present in your testimony in this proceeding?

A. Unless otherwise indicated, the source of the data is the 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 2007?

A. As outlined in Tampa Electric's annual Risk Management Plan, most recently filed on September 4, 2007 in Docket No. 070001-EI, the company follows a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. In an effort to limit exposure to market price fluctuations of natural gas, Tampa Electric established a hedging program. Over time, the program has been enhanced as Tampa Electric's gas needs have evolved and grown. All enhancements have been reviewed and approved by the company's Risk Authorization Committee.

On April 3, 2008, Tampa Electric filed its annual risk management report, which describes the outcomes of its 2007 risk management activities. The report indicates that Tampa Electric's 2007 hedging activities resulted in a net loss of $60 million. Tampa Electric followed the plan objective of reducing price volatility while maintaining a reliable fuel supply. For 2007, natural gas monthly market prices settled below the forward prices that existed at the time of the hedge transaction. The decrease in value of the hedge was a reflection of the balance of supply and demand as a result of uninterrupted gas production during the summers of 2006 and 2007 as well as the mild winter of 2006/2007.

Q. Did Tampa Electric enhance its physical hedging activities for natural gas?

A. Yes, Tampa Electric continues to enhance its physical gas supply reliability. During 2007, Tampa Electric contracted for access to natural gas supplies via the Southeast Supply Header and Gulf South. This will move about 65,000 MMBtu per day of gas supply inland, away from the Gulf Coast providing increased supply reliability during Gulf storms. While contracted in 2007, the access becomes effective in the summer of 2008.

Q. Does Tampa Electric use a hedging information system?

A. Yes, Tampa Electric continues to use Sungard's Nucleus Risk Management System ("Nucleus"). Nucleus supports sound hedging practices with its contract management, separation of duties, credit tracking, transaction limits, deal confirmation, and business report

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generation functions. The Nucleus system records all financial natural gas hedging transactions, and the system calculates risk management reports. Nucleus is also used for contract, credit management and risk exposure analysis.

Q. What were the results of the company's incremental hedging activities in 2007?

A. Tampa Electric's incremental *natural gas hedging* activities protected customers from price volatility for [redacted] of the natural gas used in the company's generating stations. The net result of natural gas hedging activity in 2007 was a loss of $60 million, when the instrument prices were compared to market prices on settled positions.

Q. Did the company use financial hedges for other commodities in 2007?

A. No, Tampa Electric did *not* use *financial hedges for* other commodities primarily because of its fuel mix.

Tampa Electric's generation is comprised mostly of coal and natural gas. Though the price of coal has increased, it is relatively stable compared to the prices of oil and natural gas. In addition, financial hedging instruments for the primary coal Tampa Electric burns, high sulfur Illinois Basin coal, do not exist.

Tampa Electric consumes a small amount of oil. However, its low and erratic usage pattern makes price hedging of oil consumption impractical; therefore, the company did not use financial hedges for oil.

The company did not use financial hedges for wholesale energy transactions because a liquid, published market does not exist in Florida.

Q. Did Tampa Electric use physical hedges for other commodities?

A. Yes, Tampa Electric used physical hedges in managing its coal supply reliability. The company enters into a portfolio of differing term contracts with various suppliers to obtain the types of coal used on its system. In previous years, Tampa Electric has been able to take advantage of contractual volume flexibility to seek out favorable spot market pricing. Those agreements have expired, and volume flexibility was not available for the replacement contracts.

Tampa Electric fills its oil tanks prior to entering hurricane season to reduce exposure to supply or price issues that may arise during hurricane season.

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

A. Commission Order No. PSC-02-1484-FOF-EI, in Docket No. 011605-EI states:

> "Each investor-owned electric utility shall be authorized 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."

Therefore, Tampa Electric's request for recovery is in accordance with the aforementioned order.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 080001-EI
FILED: 9/2/08

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 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 discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies. I will address steps Tampa Electric takes to manage fuel supply reliability and price volatility and describe projected hedging activities. I sponsor Tampa Electric's 2008 risk management plan submitted concurrently in this docket. I also present the calculation of waterborne transportation costs submitted for recovery. Finally, I describe the solid fuel transportation plan that will replace the contract that expires at the end of this year.

Q. Have you previously testified before this Commission?

A. Yes. I have testified or filed testimony before this Commission in several dockets, including Docket No. 011605-EI and 031033-EI as well as the annual fuel and purchased cost recovery dockets from 2001 through 2007. I recently filed testimony in Docket No. 080317-EI regarding Tampa Electric's request for an increase in base rates and service charges. 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 fuel transportation costs.

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

A. Yes. Exhibit No. ____ (JTW-2) describes the calculation of the 2007 waterborne transportation costs disallowance.

2009 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2009?

A. In 2009, Tampa Electric expects its fuel mix to be comparable to 2008. In 2009, natural gas-fired and coal-fired generation is expected to be 43 percent and 57 percent of total generation, respectively. Generation from No. 2 oil and No. 6 oil is less than one percent of the total expected generation.

Q. How does Tampa Electric's natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long- and short-term deliveries?

A. Tampa Electric uses a portfolio approach to natural gas procurement. The company's portfolio consists of a blend of pre-arranged base load, intermediate and swing supply complemented with daily spot purchases. The contracts have various time lengths to help secure needed supply at competitive prices and maintain the ability to take advantage of favorable natural gas price movements. Tampa Electric purchases its physical natural gas supply from many approved counterparties, enhancing liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indices, further increasing portfolio pricing diversification.

Tampa Electric has improved the reliability of the physical delivery of natural gas to its power plants by diversifying its pipeline transportation assets, including receipt points, and utilizing pipeline and storage tools to enhance access to natural gas supply during hurricanes or other events that constrain supply. On a daily basis, Tampa Electric strives to obtain reliable supplies of natural gas at favorable prices in order to minimize costs to its customers. Additionally, Tampa Electric's risk management activities improve the company's natural gas procurement activities by reducing natural gas price volatility.

Q. Please describe Tampa Electric's diversified natural gas transportation arrangements.

A. Tampa Electric historically has received its natural gas at its plants via the Florida Gas Transmission ("FGT") pipeline. The company enhanced its natural gas transportation reliability through the acquisition of pipeline capacity on Gulfstream Natural Gas System, LLC ("Gulfstream") and the Bayside Lateral. The Bayside Lateral is a 28-mile pipeline that directly connects Bayside Station to Gulfstream in Manatee County. Tampa Electric began receiving natural gas on the Bayside Lateral in June 2008. The ability to deliver natural gas directly from two pipelines enhances the fuel delivery reliability of the largest natural gas unit on Tampa Electric's system.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric has maintained natural gas storage capacity with Bay Gas Storage near Mobile, Alabama since 2005. Currently the company reserves 850,000 mmBtu of storage capacity, which enhances access to natural gas in the case of severe weather or other events that disrupt supply. Tampa Electric's storage capacity at Bay Gas Storage increases to

1,250,000 mmBtu when the fourth cavern is completed in 2010.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT Zones 1, 2 and 3. Diverse receipt points reduce the company's vulnerability to hurricane impacts in FGT Zone 3 and provide access to lower priced gas supply. Recently, Tampa Electric participated in the Southeast Supply Header ("SESH") project. SESH connects the receipt points of FGT and other Mobile Bay area pipelines with natural gas supply in the mid-continent. Mid-continent natural gas production has grown and continues to increase through non-conventional shale gas and the Rockies Express. Thus, SESH gives Tampa Electric access to secure on-shore gas supply for a small portion of its portfolio. This is beneficial because mid-continent gas supply is typically priced lower than gas supply around Mobile Bay.

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. Polk Station is an integrated gasification combined cycle plant currently burning a mix of petroleum coke and low sulfur coal. The plants have varying operational and environmental restrictions and require fuel with custom quality characteristics such as ash, fusion temperature and sulfur, heat and chlorine content. Since coal is not a homogenous product, fuel selection is based on these unique characteristics, along with price, availability, and creditworthiness of the supplier.

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

Q. Has Tampa Electric entered into coal and natural gas supply transactions for 2009 delivery?

A. Yes, Tampa Electric has contracted for a significant portion of its expected coal needs through bilateral agreements with coal suppliers to mitigate price volatility and ensure reliability of supply. Over three quarters of the company's expected 2009 coal requirements are already under contract. Tampa Electric is also in the process of soliciting suppliers for about one-half of the company's expected natural gas needs for the winter of 2008 and through 2009.

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'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 2009 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 Group ("PIRA"), Wood Mackenzie (formerly Hill & Associates), the Energy Information Administration, the New York Mercantile Exchange ("NYMEX") and other energy market information sources. Futures prices for energy commodities as traded on the NYMEX, blended with current PIRA price forecasts, form the basis of the natural gas, No. 6 oil and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry-recognized consultants and are specific to the particular quality and mined location of coal utilized by Tampa Electric's Big Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2009 projected fuel prices compare to the fuel prices projected for 2008?

A. The entire industry, including Tampa Electric, has experienced dramatic increases in fuel prices in 2008, and projected fuel prices for 2009 are expected to remain near these escalated levels. The global economy and the increasing industrialization of countries like China have affected the global balance of energy resources such as natural gas, oil, and coal. In particular, crude oil prices have soared to levels over $145 per barrel, due to factors such as the weakened U.S. dollar, the turmoil in the Middle East, and fears of declining production and growth in demand for refined products. Currently, the projected price of crude oil on NYMEX is around $115 per barrel for all of 2009. Additionally, transportation costs for the delivery of commodities have increased as the fuel used in transportation increased in price.

Q. What are the market drivers of the expected 2009 price of natural gas?

A. In addition to price pressures from crude oil, the market drivers for natural gas include increased demand from natural-gas fired generation, declining natural gas production in Canada and off-shore Gulf of Mexico, global competition for liquefied natural gas, and concerns about production losses due to tropical storm activity. Fortunately, higher than expected production of non-conventional gas supply from shale in and around Ft. Worth, Texas has mitigated some of the price pressure.

Q. What are the market drivers of the increase in the price of coal?

A. During early 2008, published price curves for 2009 delivery of Illinois Basin coal increased over 50 percent. There are several factors driving this dramatic increase. First, many northeast utilities are replacing lower sulfur Northern or Central Appalachian coal that has been diverted into the export market with Illinois Basin coal. Demand for Illinois Basin coal has also increased as many utilities that historically burned lower sulfur coals are installing environmental equipment which allows them to burn Illinois Basin coal. Additionally, several producers in the Illinois Basin continue to experience significant geologic issues reducing available production.

Coal prices correlate with the prices of other fuels since coal mining utilizes petroleum products, steel, and lumber in its production processes; therefore, coal prices have increased in conjunction with increases in the prices of these commodities and other fuels. The industry as a whole has experienced a severe labor shortage. Coal companies have had to increase compensation packages to attract or keep their work forces, adding to the escalating mining costs. Thus, Tampa Electric expects higher coal prices to continue through 2009.

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

A. Yes. Tampa Electric prepared a scenario in which the forecasted fuel prices were 26 percent and 31 percent higher for natural gas and No. 2 oil, respectively. Similarly, Tampa Electric prepared a scenario in which the forecasted fuel prices were 23 percent and 41 percent lower for natural gas and No. 2 oil, respectively. These percentages were derived from the actual price variation of these fuels during the past five years. The causes of potential price uncertainty include weather, political turmoil, global economics, commodity demand and production, and transportation issues.

Risk Management Activities

Q. Please describe Tampa Electric's risk management activities.

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa Electric's plan is described in detail in the Risk Management plan filed simultaneously in this docket.

Q. Does Tampa Electric's risk management strategy help to mitigate natural gas price risk?

A. Yes. To help protect customers from price volatility, Tampa Electric's plan allows for purchases of over-the-counter natural gas swaps, options and collars. A swap is a financial derivative that provides a "fixed for floating" position. Tampa Electric, the buyer, pays a fixed price for the natural gas contract, compared to a floating value that settles in a future month when the gas supply is needed. Swaps allow Tampa Electric to lock in known natural gas prices and reduce price volatility and uncertainty. The transaction costs of swaps are embedded in the price of the commodity.

Options give Tampa Electric the right, but not the obligation, to buy (call) or sell (put) natural gas at a predetermined price for a given future month. Tampa Electric pays a premium at the time of the option purchase for this right.

Collars are combinations of call options (caps) and put options (floors) that limit prices within a certain range.

With a collar, the company knows that its future price will remain within predetermined boundaries.

Q. Has Tampa Electric used financial hedging in an effort to help mitigate the price volatility of its 2008 and 2009 natural gas requirements?

A. Yes. Tampa Electric has hedged a significant portion of its 2008 natural gas supply needs and a portion of its expected 2009 natural gas supply needs. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with the company's approved Risk Management Plan. The current market position for natural gas hedges is provided in the Risk Management Plan.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2008 and 2009 natural gas purchases?

A. Yes, the company's strategies are adequate for mitigating price risk for Tampa Electric's natural gas purchases. Tampa Electric's strategies balance the desire for reduced price volatility and reasonable cost with the uncertainty of natural gas volumes. These strategies are described in detail in Tampa Electric's Risk Management Plan filed concurrently in this docket.

Q. How does Tampa Electric determine the volume of natural gas it plans to hedge?

A. First, Tampa Electric projects the quantity or volume of natural gas expected to be consumed in its power plants. The volume hedged is driven primarily by the projected total gas levels by month and the time until that natural gas is needed. Based on those two parameters, the amount hedged is maintained within a range authorized by the company's Risk Authorizing Committee. The market price of natural gas does not affect the percentage of natural gas requirements that the company hedges since the objective is price volatility reduction, not price speculation.

Next, Tampa Electric considers the quantity of natural gas that it is responsible to supply under a purchased power agreement ("PPA"). Tampa Electric has two agreements where the company is responsible for the fuel supply. Since these PPA's are recent additions to its portfolio, Tampa Electric is not currently including these volumes in its hedging portfolio. Once Tampa Electric has more experience with the PPA's, it will reassess whether to add the natural gas volumes to the consumed natural gas volumes.

Q. Were Tampa Electric's efforts through July 31, 2008 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. On April 1, 2008, the company filed its 2007 hedging results as part of the final true-up process. Additionally, Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, requires the utilities to file a Hedging Information Report showing the results of hedging activities from January through July of the current year. The Hedging Information Report facilitates prudence reviews through July 31 of the current year and allows for the Commission's prudence determination at the annual fuel hearing. Tampa Electric filed its Hedging Information Report showing the results of its prudent hedging activities from January through July 2008 in this docket on August 15, 2008.

Coal Transportation Costs

Q. Did Tampa Electric calculate the waterborne transportation costs submitted for cost recovery in accordance with the

Commission's Order No. PSC-04-0999-FOF-EI ("Order No. 04-0999"), issued in Docket No. 031033-EI on October 12, 2004?

A. Yes. The waterborne transportation costs that Tampa Electric is seeking to recover are the adjusted river rates per ton for each upriver terminal as well as the adjusted ocean barge transportation rate per ton. The company calculates the adjusted rates as described in Order No. 04-0999. The river rate is adjusted using the following formula:

$$\frac{\text{(Weighted average rate per ton for all upriver terminals - \$1/ton)}}{\text{Weighted average rate per ton for all upriver terminals}} \times \text{Contract rate for specific upriver terminal}$$

The ocean rate is reduced by $2.41 per ton for shipments from the Davant, Louisiana terminal and $4.08 per ton for petroleum coke shipments from Texas, as prescribed by the Commission order.

For 2007, Tampa Electric's adjustment to its total waterborne transportation costs totaled $15,142,720. The total 2007 adjustment recorded in Tampa Electric's final true-up filing, submitted in this docket on March 1, 2008, was calculated using the actual tons of coal and petroleum coke shipped in 2007 and the methodology required by Order No. 04-9999. These calculations are shown in Exhibit No. ____ (JTW-2).

Therefore, Tampa Electric's 2007 adjusted coal transportation costs are appropriate for recovery through the Fuel and Purchased Power Cost Recovery Clause.

Likewise, the expected 2008 waterborne transportation costs have been adjusted using this same methodology according to Order No. 04-0999 and will be revised to reflect the actual tons shipped and associated calculated disallowances as part of the normal true-up process. Accordingly, it is also appropriate for Tampa Electric to recover its allowable 2008 projected transportation expenses included in the fuel clause for coal transportation.

The transportation contract and the recovery adjustment period will expire on December 31, 2008. Tampa Electric has complied with Order No. 04-0999 by adjusting the amount of the waterborne coal transportation contract costs recovered through the fuel clause for the entire period that the contract is in effect, from January 1, 2004 through December 31, 2008. The company has consistently followed the prescribed methodology in Order No. 04-0999 in calculating the disallowance amount for both the river and ocean transportation contract rates. A final adjustment will be made to true up the actual tons shipped in 2008 and associated calculated disallowances as part of the final 2008

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true-up.

Q. Did Tampa Electric enter into a new contract for coal transportation for 2009 and beyond?

A. Yes, Tampa Electric has selected three contracts to replace the expiring solid fuel transportation contract. Tampa Electric signed a six-year contract with United Marine Group ("UMG") for waterborne transportation and delivery of up to [redacted] tons of coal per year to Big Bend Station. The contract also provides the flexibility to increase UMG's waterborne transportation deliveries by [redacted] tons per year. UMG will begin delivery under the new contract on January 1, 2009. Tampa Electric is in the process of negotiating a second contract with CSX railroad. CSX will deliver approximately [redacted] tons of coal per year to Big Bend Station once construction of rail unloading facilities at Big Bend Station is completed in early 2010. The company is also negotiating with AEP Memco, LLC for river barging services beginning in 2009. This contract will be for transportation of up to [redacted] tons from locations on the Mississippi River to New Orleans.

Q. Please describe the RFP process that resulted in the selection of the transportation providers.

A. The RFP process was comprehensive, open and fair. Throughout the process, Tampa Electric's objective was to develop a comprehensive strategy to provide cost-effective solid fuel and transportation services for the benefit of its customers. Prior to and concurrent with the bid, site visits and meetings were held with various potential respondents. The RFP was published in several solid fuel industry publications and was sent to 41 potential bidders. The RFP was downloaded by 23 different transportation providers. The company hosted a post-release bid meeting on October 24, 2007 in Tampa to invite participation in the RFP and share information about Tampa Electric's need for solid fuel transportation services. The company developed a website for distribution of information to bidders, including the RFP process timeline, answers to frequently asked questions, and the bid documents.

Tampa Electric utilized an independent consultant, Energy Ventures Analysis, Inc. ("EVA"), to monitor the RFP process for effectiveness and review the selection results. Dr. Robert Sansom and Mr. Seth Schwartz of EVA collectively have over 40 years of experience in the coal and transportation consulting business. They are leaders in their field, and their firm has a variety of clients including utilities, coal companies, transportation providers, banks, and governmental and regulatory agencies. Dr. Sansom and Mr. Schwartz provided the company with key data regarding the coal and transportation markets and assisted the company with strategic analysis of comprehensive solid fuel delivery packages for the next five years.

Concurrent with the RFP for transportation, Tampa Electric issued an RFP for coal supply. The company evaluated the delivered costs of the combined transportation and coal offers. Each transportation segment included coal commodity costs, oil forecast and other price factors to evaluate prices over the term of the contracts. Collectively, these steps assured an open, fair and comprehensive solid fuel transportation selection process.

Q. Did Tampa Electric make any other efforts to ensure the RFP process was open and fair?

A. Yes, Tampa Electric provided a steady flow of information to the FPSC staff and docket parties throughout the process. The company met with Staff and parties to determine a proxy methodology early in the process in spring 2007. During fall 2007, Tampa Electric provided draft RFP documents for review and informed all parties of plans for external bidder meetings, updates to the website and other communications. The company provided updates regarding preliminary RFP results in April and June 2008, and the final decisions will be discussed with Staff and all parties at a meeting scheduled for September 3, 2008.

Q. How did the winning bids compare to other proposals?

A. The winning bids are the most cost-effective packages offered by the bidders that provide low cost, reliable solid fuel transportation. The selected bids also provide the ability to access a diverse supply of solid fuels in new supply basins. The winning packages of transportation provide strategic value for the company and its customers.

Q. How do the 2009 transportation costs compare to costs under the previous contract in 2008?

A. The solid fuel transportation rates under the three new contracts are expected to be higher than the rates under the expiring solid fuel transportation contract. On a total basis, 2009 transportation costs are expected to be approximately $14 million greater than costs in 2008. The increase is driven by increases in fuel costs, particularly diesel, and also by the high level of demand for shipping in general. However, Tampa Electric believes dual transportation modes for solid fuel to Big Bend Station will provide ongoing supply reliability enhancements, competitive transportation supply and cost savings opportunities that benefit customers.

Q. What is your recommendation regarding the RFP process, analysis and selection of the winning providers?

A. The process was comprehensive, fair and reasonable. Tampa Electric analyzed the bids and selected the most cost-effective options. Under the new contracts, Tampa Electric will accept solid fuel shipments at Big Bend Station by rail and water routes. The company's ability to ship fuel directly to the station by two different modes beginning in 2010 will enhance supply reliability and provide long-term cost advantages. Tampa Electric requests that the Commission recognize the overall value of the winning contracts and authorize the company to recover those costs.

Q. Does this conclude your testimony?

A. Yes, it does.

CHAIRMAN CARTER: Okay. Now let's back up and take it from the top. You're recognized.

MR. BEASLEY: Mr. Buckley has already been stipulated, so his exhibit and Mr. Knapp's Exhibit 47 which he sponsors, those, I would ask that they be made part of the record.

CHAIRMAN CARTER: Are there any questions from staff of Witnesses Knapp and Buckley?

MS. BENNETT: There are none. This is the GPIF witness, so both their exhibits and their testimony could be entered into the record because they were excused.

CHAIRMAN CARTER: Parties? The prefiled testimony of Witnesses -- wait a minute. One second. Commissioners? The prefiled testimony of Witnesses Knapp and Buckley will be entered into the record as though read. Exhibits?

MS. BENNETT: Those would be Exhibits 47 and 48.

CHAIRMAN CARTER: Any objection? Without objection, show it done.

(Exhibits 47 and 48 admitted into the record.)

Also consistent with the stipulation these witnesses are excused. And does that conclude all matters with Witnesses Knapp and Buckley?

MS. BENNETT: Yes, Mr. Chairman.

CHAIRMAN CARTER: Thank you. Okay. So we've entered into exhibits, entered into the record Exhibits 47 and 48 and completed matters as it relates to Witnesses Knapp, Buckley, Wehle -- did I get it right that time?

MR. BEASLEY: Yes, sir. That's correct. Very good.

CHAIRMAN CARTER: There's hope for tomorrow. Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID R. KNAPP

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

A. My name is David R. Knapp. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as a Supervisor in the Operations Planning area of the Resource Planning Department.

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

A. I received a Bachelor of Marine Engineering degree in 1986 from the Maine Maritime Academy and a Master of Business Administration from the University of Tampa in 2002. Prior to joining Tampa Electric, I worked in the areas of operations engineering and management. In January 1996, I joined Tampa Electric and worked in field operations and power plant engineering. In April 2000, I transferred to the Resource Planning department, where I led a team that provides engineering and technical support in the development of Tampa Electric's integrated resource planning process and business planning activities. In December 2006, I transferred to the Operations Planning area of the Resource Planning, and in September 2007, I was promoted to Supervisor. I provide engineering and technical support for the daily operations of Tampa Electric's generating facilities.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and station heat rate used to determine the GPIF for the period January 2007 through December 2007. I will also compare these results to the targets established prior to the beginning of the period.

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

A. Yes, I prepared Exhibit No. _____ (DRK-1), consisting of two documents. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2007 - December 2007 True-up" is consistent with the GPIF Implementation Manual previously approved by the Commission.

In addition, Document No. 2 provides the company's Actual Unit Performance Data for the 2007 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and one natural gas combined cycle unit are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Unit 1.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2007 through December 2007 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 30. Based upon -1.482 GPIF points, the result is a penalty amount of $849,634 for the period.

Q. Please proceed with your review of the actual results for the January 2007 through December 2007 period.

A. On Document No. 1, page 3 of 30, the actual average common equity for the period is shown on line 14 as $1,459,328,846. This produces the maximum penalty or reward amount of

$5,731,699 as shown on line 21.

Q. Will you please explain how you arrived at the actual equivalent availability results for the six units included within the GPIF?

A. Yes. Operating data for each of the units is filed monthly with the Commission on the Actual Unit Performance Data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the 12 months provides the basis for the GPIF.

Q. Are the equivalent availability results shown on Document No. 1, page 6 of 30, column 2, directly applicable to the GPIF table?

A. No. Adjustments to equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 30. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 1

On this unit, 336.0 planned outage hours were originally scheduled for 2007. Actual outage activities required 0.0 planned outage hours. Consequently, the actual equivalent availability of 76.3 percent is adjusted to 73.4 percent as shown on Document No. 1, page 7 of 30.

Big Bend Unit No. 2

On this unit, 504.0 planned outage hours were originally scheduled for 2007. Actual outage activities required 218.8 planned outage hours. Consequently, the actual equivalent availability of 79.5 percent is adjusted to 76.8 percent as shown on Document No. 1, page 8 of 30.

Big Bend Unit No. 3

On this unit, 744.0 planned outage hours were originally scheduled for 2007. Actual outage activities required 1,033.8 planned outage hours. Consequently, the actual equivalent availability of 46.5 percent is adjusted to 48.2 percent as shown on Document No. 1, page 9 of 30.

Big Bend Unit No. 4

On this unit, 2,136.0 planned outage hours were originally scheduled for 2007. Actual outage activities required 2,368.0 planned outage hours. Consequently, the actual equivalent availability of 53.2 percent is adjusted to 55.1 percent as shown on Document No. 1, page 10 of 30.

Polk Unit No. 1

On this unit, 288.0 planned outage hours were originally scheduled for 2007. Actual outage activities required 356.3 planned outage hours. Consequently, the actual equivalent availability of 85.0 percent is adjusted to 85.6 percent, as shown on Document No. 1, page 11 of 30.

Bayside Unit No. 1

On this unit, 840.0 planned outage hours were originally scheduled for 2007. Actual outage activities required 1,007.3 planned outage hours. Consequently, the actual equivalent availability of 85.2 percent is adjusted to 87.0 percent, as shown on Document No. 1, page 12 of 30.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 30, column 4. This number is entered into the respective Generating Performance Incentive Point ("GPIP") table for each particular unit on pages 13 of 30 through 18 of 30. Page 4 of 30 summarizes the equivalent availability points to be awarded or penalized.

Q. Will you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for Tampa Electric's six GPIF units are shown on Document No. 1, page 6 of 30. The adjustment was developed based on the guidelines of section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 30. The heat rate value is entered into the respective GPIP table for the particular unit, shown on pages 13 of 30 through 18 of 30. Page 4 of 30 summarizes the weighted heat rate and equivalent availability points to be awarded.

Q. What is the overall GPIP for Tampa Electric for the January 2007 through December 2007 period?

A. This is shown on Document No. 1, page 2 of 30. Essentially, the weighting factors shown on page 4 of 30, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 30, column 4, are substituted within the equation. The resulting value, -1.482, is then entered into the GPIF table on page 2 of 30. Using linear interpolation, the penalty amount is $849,634.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 080001-EI
FILED: 9/2/2008

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Supervisor, Performance Planning & Analysis in the Resource Planning Department.

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

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including Operations Engineer at Gannon Station, Instrumentation and Controls Engineer at Big Bend Station, and Senior Engineer in Asset Management. In August 2007, I was promoted to Supervisor, Performance Planning and Analysis in the Resource Planning department, where I am currently responsible for unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric's maintenance planning processes and presents Tampa Electric's methodology for determining the various factors required to compute the Generating Performance Incentive Factor ("GPIF") as ordered by the Commission.

Q. Have you prepared any exhibits to support your testimony?

A. Yes, Exhibit No. ____ (BSB-1), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2009 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Do the exhibits you prepared comply with Commission-approved GPIF methodology?

A. Yes, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission. To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. Section 3.3 of the GPIF Implementation Manual allows for removal of outliers, and the methodology was approved by the Commission in Order No. PSC-06-1057-FOF-EI issued in Docket No. 060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. One outage from Big Bend Unit 2, one outage from Big Bend Unit 3, and one outage from Big Bend Unit 4 were identified as outlying outages; therefore, the associated forced outage hours were removed from the study.

Q. Please describe how Tampa Electric developed the various factors associated with the GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2009 period. A range of potential improvements and degradations were determined for each of these metrics.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor or POF and the Equivalent Unplanned Outage Factor or EUOF were subtracted from 100 percent to determine the target Equivalent Availability Factor or EAF. The factors for each of the seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2009 period, the projected

Equivalent Unplanned Outage Factor for Big Bend Unit 1 is 18.2 percent, and the Planned Outage Factor is 9.3 percent. Therefore, the target equivalent availability factor for Big Bend Unit 1 equals 72.5 percent or:

$$100\% - (18.2\% + 9.3\%) = 72.5\%$$

This is shown on page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived by using the following formula:

$$EAF_{MAX} = 1 - [0.8 \; (EUOF_T) + 0.95 \; (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in Equivalent Forced Outage Factor or EUOF and Equivalent Maintenance Outage Factor or EMOF, plus a five percent reduction in the Planned Outage Factor are necessary. Continuing with the Big Bend Unit 1 example:

$$EAF_{MAX} = 1 - [0.8\ (18.2\%) + 0.95\ (9.3\%)] = 76.6\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing with the Big Bend Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (18.2\%) + 1.10\ (9.3\%)] = 64.3\%$$

The equivalent availability maximum and minimum for the other six units are computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January through December 2009 are shown on page 21 of Document No. 1. Four GPIF units have a major outage of 28 days or greater in 2009; therefore, four Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 1 is scheduled for a planned outage from November 28, 2009 to December 31, 2009. There are 816 planned outage hours scheduled for the 2009 period, and a total of 8,760 hours during this 12-month period. Consequently, the Planned Outage Factor for Big Bend Unit 1 is 9.3 percent or:

$$\frac{816}{8,760} \times 100\% = 9.3\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a Planned Outage Factor of 9.3 percent. Big Bend Unit 2 has a Planned Outage Factor of 32.6 percent. Big Bend Unit 3 has a Planned Outage Factor of 3.8 percent. Big Bend Unit 4 has a Planned Outage Factor of 15.3 percent.

Polk Unit 1 has a Planned Outage Factor of 9.8 percent. Bayside Unit 1 has a Planned Outage Factor of 3.8 percent, and Bayside Unit 2 has a Planned Outage Factor of 3.8 percent.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. For each unit the most current 12-month ending value, June 2008, was used as a basis for the projection. All projected factors are based upon historical unit performance unless adjusted for outlying forced outages. These target factors are additive and result in an Equivalent Unplanned Outage Factor of 18.2 percent for Big Bend Unit 1. The Equivalent Unplanned Outage Factor for Big Bend Unit 1 is verified by the data shown on page 14, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

Or

$$EUOF = \frac{(1{,}368 + 224)}{8{,}760} \times 100\% = 18.2\%$$

Relative to Big Bend Unit 1, the EUOF of 18.2 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 18.2 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 9.3 percent. Therefore, the target equivalent availability for this unit is 72.5 percent.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 11.3 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 32.6 percent. Therefore, the target equivalent availability for this unit is 56.1 percent.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 41.8 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 3.8 percent. Therefore, the target equivalent availability for this unit is 54.3 percent.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 17.2 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 15.3 percent. Therefore, the target equivalent availability for this unit is 67.5 percent.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 10.6 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 9.8 percent. Therefore, the target equivalent availability for this unit is 79.7 percent.

Bayside Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 2.8 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 3.8 percent. Therefore, the target equivalent availability for this unit is 93.4 percent.

Bayside Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 2.0 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 3.8

percent. Therefore, the target equivalent availability for this unit is 94.1 percent.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 62.7 percent is shown on Page 5 of Document No. 1. This target is comparable to the 2007 January through December actual performance.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend Unit 1 on page 14 of Document No. 1. During the months of January through October and December, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the month of November, the

Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to a scheduled planned outage. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining the unit metrics, which are subsequently converted to factors. Therefore,

$$EFOF + EMOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the aforementioned agreed upon GPIF methodology.

Q. How were these targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis of the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 33 through 39 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by computer program for each unit. These curves are also used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2009 period.

A. The heat rate target for Big Bend Unit 1 is 10,774 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±302 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,396 Btu/Net kWh with a range of ±291 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,751 Btu/Net kWh, with a range of ±293 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,598 Btu/Net kWh with a range of ±454 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,707 Btu/Net kWh with a range of ±753 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,264

Btu/Net kWh with a range of ±102 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,378 Btu/Net kWh with a range of ±101 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 13 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 13. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $1,492,425.10 is shown on page 6, column 2.

Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

After all of the individual savings are calculated, column 4 totals $60,487,101 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Big Bend Unit 1, the weighting factor for equivalent availability is 8.9 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend Unit 1, page 7, if the unit operates at 76.6 percent equivalent availability, fuel savings would equal $5,381,600, and 10 equivalent availability points would be awarded.

The GPIF Reward/Penalty table on page 2 is a summary of the tables on pages 7 through 13. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $60,487,101. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2009 is $2,071,043,308. This produces the maximum allowed jurisdictional incentive of $8,123,043 shown on line 21.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met.

Q. Please summarize your testimony.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$\begin{aligned} GPIP: = (\ & 0.0890\ EAP_{BB1} + 0.0704\ EAP_{BB2} \\ & + 0.2222\ EAP_{BB3} + 0.1042\ EAP_{BB4} \\ & + 0.0309\ EAP_{PK1} + 0.0067\ EAP_{BAY1} \\ & + 0.0070\ EAP_{BAY2} + 0.0451\ HRP_{BB1} \\ & + 0.0329\ HRP_{BB2} + 0.0342\ HRP_{BB3} \\ & + 0.0711\ HRP_{BB4} + 0.1081\ HRP_{PK1} \\ & + 0.0906\ HRP_{BAY1} + 0.0876\ HRP_{BAY2}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2009 period?

A. Yes. Document No. 2 entitled "Summary of GPIF Targets" provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

CHAIRMAN CARTER: You're recognized.

MR. BEASLEY: Yes, sir. I would call Mr. Aldazabal to the stand.

CHAIRMAN CARTER: I'm glad you said it. Have you been sworn?

THE WITNESS: No.

CHAIRMAN CARTER: Okay. Let's do this then. Will all the witnesses, TECO witnesses that are going to testify today -- it's just, I guess it's just Mr. -- help me with the name again.

MR. BEASLEY: I believe it will be Mr. Aldazabal unless --

CHAIRMAN CARTER: Aldazabal?

MR. BEASLEY: Yes, sir.

CHAIRMAN CARTER: Was I close?

THE WITNESS: That's close.

CHAIRMAN CARTER: Thank you, sir.

MS. BENNETT: And also Mr. Smith.

CHAIRMAN CARTER: And Mr. Smith. Would you please stand and raise your right hand.

(Witnesses collectively sworn.)

Thank you. Please be seated.

You're recognized, sir.

MR. BEASLEY: Thank you.

CARLOS ALDAZABAL

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

DIRECT EXAMINATION

BY MR. BEASLEY:

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

A Yes. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602, and my title is Manager of Regulatory Affairs.

Q Mr. Aldazabal, did you file in this proceeding on March 3 final 2007 true-up testimony, and on August 4 actual estimated true-up testimony for 2008, and on September 2nd projected 2009 testimony, and finally on October 3rd revisions to your true-up and projected testimonies?

A The revisions were on October 13th, yes.

Q October 13. Yeah. If I were to ask you the questions in that testimony, would your answers be the same?

A Yes, they would.

MR. BEASLEY: I'd ask that all of the testimonies that I just identified be inserted into the record as though read.

CHAIRMAN CARTER: The prefiled testimony of the witness will be entered into the record as though read.

MR. BEASLEY: Thank you.

BY MR. BEASLEY:

Q Mr. Aldazabal, did you also prepare and submit exhibits identified in the Prehearing Order as CA-1, 2 and 3 as well as revised pages filed October 13?

A Yes, I did.

MR. BEASLEY: Thank you. And those have been marked for identification.

Mr. Aldazabal addresses the fuel adjustment true-up projections and cost recovery factor calculations that flow from the company-specific issues that have already been --

CHAIRMAN CARTER: Excuse me. Hang on one second. Let me interrupt you.

Mr. McWhirter, on the witnesses that we just took care of, did you have any concerns or questions on those? Because we've already entered them into the record as it relates to Knapp, Buckley and Wehle.

MR. McWHIRTER: No, ma'am. No, sir.

CHAIRMAN CARTER: Okay. That's good enough.

MR. McWHIRTER: I apologize for that.

CHAIRMAN CARTER: No is fine. I try not to wear spike heels during the day.

MR. McWHIRTER: I'm used to answering my wife.

CHAIRMAN CARTER: That's probably why you've lived so long.

(Laughter.)

It's a great day in America, isn't it?

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Regulatory Affairs in the Regulatory Affairs Department.

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy from the University of South Florida in Tampa in 1995. I am a CPA in the State of Florida and have accumulated 13 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory

Accounting. In January 2004, I was promoted to Manager, Regulatory Affairs. My present responsibilities include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2007 through December 2007 for both the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause ("capacity clause"). I also present the wholesale incentive benchmark for January 2008 through December 2008 as well as the actual incremental operation and maintenance ("O&M") security alert and North American Electric Reliability Council ("NERC") cyber security expenses for the period January 2007 through December 2007.

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

A. Unless otherwise indicated, the actual data is taken from the 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 the Florida Public Service Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

A. Yes. Exhibit No.___ (CA-1), consisting of four documents which are described in my testimony, was prepared under my direction and supervision.

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Cost Recovery Clause for the period January 2007 through December 2007?

A. The final true-up amount for the capacity clause for the period January 2007 through December 2007 is an under-recovery of $3,726,521.

Q. Please describe Document No. 1 of your exhibit.

A. Document No. 1, page 1 of 5, entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of

Final True-up Variances for the Period January 2007 Through December 2007", provides the calculation for the final under-recovery of $3,726,521. The actual capacity cost under-recovery, including interest was $27,523,105 for the period January 2007 through December 2007 as identified in Document No. 1, pages 1 and 2 of 5. This amount, less the $23,796,584 actual/estimated under-recovery approved in Order No. PSC-08-0030-FOF-EI issued January 08, 2008 in Docket No. 070001-EI, results in a final under-recovery for the period of $3,726,521 as identified in Document No. 1, page 4 of 5. This under-recovery amount will be applied in the calculation of the capacity cost recovery factors for the period January 2009 through December 2009.

Q. What is the estimated effect of this $3,726,521 under-recovery for the January 2007 through December 2007 period on residential bills during January 2009 through December 2009?

A. The $3,726,521 under-recovery will increase a 1,000 kWh residential bill by approximately $0.18.

Incremental Security Alert Expenses

Q. What were Tampa Electric's actual 2007 incremental O&M

security alert and NERC cyber security expenses as a result of the events of September 11, 2001?

A. As shown in Document No. 1, Page 2 of 5, line 4, Tampa Electric incurred $906,044 for incremental O&M security and NERC cyber security expenses for measures taken by the company to protect its generating facilities for the period January 2007 through December 2007.

Q. How did the actual incremental O&M security and NERC cyber security costs compare to the costs included in the 2007 Actual/Estimated capacity filing?

A. Actual incremental O&M security and NERC cyber security costs were $99,849 lower than projected in the 2007 Actual/Estimated capacity filing. The variance is the result of the deferral of a multi-governmental agency project.

Q. Is Tampa Electric's methodology used to calculate incremental security costs consistent with the one described in Order No. PSC-03-1461-FOF-EI, issued December 22, 2003?

A. Yes. To calculate incremental security costs, Tampa

Electric compared its actual total O&M security guard expenses to baseline expenses or pre-9/11 annual security expenses. Incremental expenses to comply with new NERC cyber security requirements due to the events of September 11, 2001 were also identified. All incremental security costs were separately identified, and any savings gained through the implementation of any security related projects were credited pursuant to the method described in Order No. PSC-03-1461-FOF-EI, issued December 22, 2003.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel and Purchased Power Cost Recovery Clause for the period January 2007 through December 2007?

A. The final fuel clause true-up for the period January 2007 through December 2007 is an under-recovery of $21,121,127. The actual fuel cost under-recovery, including interest, was $5,728,415 for the period January 2007 through December 2007. This $5,728,415 amount, less the $15,392,712 actual/estimated over-recovery amount approved in Order No. PSC-08-0030-FOF-EI, issued January 08, 2008 in Docket No. 070001-EI results in a net under-recovery amount for the period of

$21,121,127.

Q. What is the estimated effect of the $21,121,127 under-recovery for the January 2007 through December 2007 period on residential bills during January 2009 through December 2009?

A. The $21,121,127 under-recovery would increase a 1,000 kWh residential bill by approximately $1.04.

Q. Please describe Document No. 2 of your exhibit.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2007 Through December 2007". It shows the calculation of the final fuel under-recovery of $21,121,127.

Line 1 shows the total company fuel costs of $1,034,958,950 for the period January 2007 through December 2007. The jurisdictional amount of total fuel costs, which includes the Commission ordered waterborne coal transportation expense disallowance, is $998,392,983, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual under-recovered fuel costs for the period, shown on line 4. The resulting $1,350,107 over-recovered fuel costs for the period, combined with the interest, true-up collected and the prior period true-up shown on lines 5, 6 and 7, respectively, constitute the actual under-recovery of $5,728,415 shown on line 8. The $5,728,415 actual under-recovery amount less the $15,392,712 actual/estimated over-recovery amount shown on line 9, results in a final $21,121,127 under-recovery amount for the period January 2007 through December 2007 as shown on line 10.

Q. Please describe Document No. 3 of your exhibit.

A. Document No. 3 entitled "Tampa Electric Company Calculation of True-up Amount Actual vs. Original Estimates for the Period January 2007 Through December 2007", shows the calculation of the actual under-recovery as compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2007 through December 2007?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost variance is $29,161,096 less than what was originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2007 through December 2007?

A. As shown on line C3 of Document No. 3, the company collected $34,632,851 or 3.3 percent less jurisdictional fuel revenues than originally estimated.

Q. Please describe Document No. 4 of your exhibit.

A. Document No. 4 contains Commission Schedules A1 through A9 for the months of January 2007 through December 2007. Also included is a twelve-month summary detailing the transactions for each of Commission Schedules A6, A7, A8, A9 and A12 for the period January 2007 through December 2007.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2008, as derived in accordance with Order No. PSC-01-2371-FOF-EI, Docket No. 010283-EI?

A. The company's 2008 benchmark is $811,478, which is the three-year average of $878,238, $757,156, and $799,040 actual gains on non-separated wholesale sales, excluding emergency sales, for 2005, 2006 and 2007, respectively.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 080001-EI
FILED: 8/4/08

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Regulatory Affairs in the Regulatory Affairs Department.

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and a Masters of Accountancy in 1995 from the University of South Florida in Tampa. I am a CPA in the State of Florida and have accumulated 13 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, budgeting and analysis, and cost recovery clause management. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I was promoted to Manager, Regulatory Affairs. My present responsibilities include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

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 January 2008 through December 2008 fuel and purchased power and capacity true-up amounts to be recovered in the January 2009 through December 2009 projection period. My testimony addresses the recovery of fuel and purchased power costs, capacity costs and incremental O&M security costs for the year 2008, based on six months of actual data and six months of estimated data. In addition, my testimony addresses the adjustment to fuel and purchased power costs as required in Order No. PSC-04-0999-FOF-EI (the "Order"). This information will be used in the determination of the 2009 fuel and purchased power costs and capacity cost recovery factors.

Q. Have you prepared any exhibits to support your testimony?

A. Yes. I have prepared Exhibit No. ____ (CA-2), which contains two documents. Document No. 1 is comprised of Schedules E1-B, E-2, E-3, E-5, E-6, E-7, E-8, and E-9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2008 through December 2008. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2008 through December 2008. These documents are furnished as support for the projected true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2009 through December 2009 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2009 through December 2009 is an under-recovery of $132,882,938.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2009 through December 2009 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2009 is the sum of the final true-up amount for the period January 2007 through December 2007 and the actual/estimated true-up amount for the period January 2008 through December 2008.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2007?

A. The true-up was an under-recovery of $21,121,127. The actual fuel cost under-recovery, including interest and the waterborne transportation cost adjustment, was $5,728,415 for the period January 2007 through December 2007. The $5,728,415 amount, less the actual/estimated over-recovery amount of $15,392,712 approved in Order No. PSC-08-0030-FOF-EI, issued January 08, 2008 in Docket No. 070001-EI results in a net under-recovery amount for the period of $21,121,127.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2008 through December 2008?

A. The actual/estimated fuel and purchased power cost recovery true-up is an under-recovery amount of $111,761,811 for the January 2008 through December 2008 period. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit No. ____ (CA-2), Document No. 1 on Schedule E1-B.

Q. Has Tampa Electric's fuel cost recovery been appropriately adjusted as required by Order No. PSC-04-0999-FOF-EI issued October 12, 2004 in Docket No. 031033-EI?

A. Yes, Tampa Electric adjusted its fuel expense for the disallowance of costs required by The Order, which specifies that a portion of the costs incurred by Tampa Electric under the current contract with United Maritime Group, formerly TECO Transport, is not reasonable for cost recovery. The Order contemplates levelized annually recurring disallowances and Tampa Electric has complied with the Order by adjusting the amount of the waterborne coal transportation contract costs recovered through the fuel factor for 2008, just as it did for 2004 through 2007. The company has consistently calculated the disallowances in accordance with The Order, whereby specific reductions are applied to the rate for shipments from each upriver terminal and also reduced for cross gulf shipments to Big Bend Station. Specific monthly tonnage and river dock information was provided by the

Wholesale Marketing and Fuels group to Regulatory Accounting in order to properly capture and exclude the disallowance amounts from the fuel cost recovery clause. The transportation contract will expire on December 31, 2008 at which time the annual recovery adjustment will end. The 2008 adjustment will be trued up to reflect the actual tons shipped and associated calculated disallowances as part of the final 2008 true-up.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2009 through December 2009 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2009 through December 2009 is an under-recovery of $19,828,942 as shown in Exhibit No. ____ (CA-2), Document No. 2, page 2 of 6.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2009 through December 2009 capacity cost recovery factors?

A. Tampa Electric calculated the net true-up amount to be recovered in 2009 in the same manner as previously described for the fuel and purchased power cost recovery net true-up amount. The net true-up amount to be recovered in the 2009 capacity cost recovery factors is the sum of the final true-up amount for 2007 and the actual/estimated true-up amount for January 2008 through December 2008.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2007?

A. The true-up was an under-recovery of $3,726,521. The actual capacity cost under-recovery including interest was $27,523,105 for the period January 2007 through December 2007. The $27,523,105 amount, less the actual/estimated under-recovery amount of $23,796,584 approved in Order No. PSC-08-0030-FOF-EI issued January 08, 2008 in Docket No. 070001-EI results in a net under-recovery amount for the period of $3,726,521 as identified in Exhibit No. ____ (CA-2), Document No. 2, page 1 of 6.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2008 through December 2008?

A. The actual/estimated true-up amount is an under-recovery of $16,102,421 as shown on Exhibit No. ____ (CA-2), Document No. 2, page 1 of 6.

Q. Are incremental security O&M costs included for cost recovery through the capacity clause?

A. Yes. Given the Commission's previous authorization to recover incremental security O&M costs arising as a result of the extraordinary circumstances of the terrorist attacks of September 11, 2001, Tampa Electric's incremental security O&M costs are included for recovery through the capacity clause. Therefore, as shown on Exhibit No. ____ (CA-2), Document No. 2, Page 4 of 6 the company requests recovery of $2,203,783, after jurisdictional separation, for 2008 actual/estimated incremental security O&M expenses.

Q. How does this amount vary from the original projection?

A. The actual/estimated incremental security O&M expenses are $205,797 greater than the original projected costs. The variance is primarily due to additional actions required to meet NERC standards, compared to expected security changes and associated costs at the time of the original 2008 cost estimate. For example, during the course of implementing the NERC cyber security requirements, the company determined that it was necessary to secure additional critical cyber assets by relocation to a physically secured perimeter, additional guard monitoring, and additional secured checkpoints for access and control of generating assets at the plants.

Q. Did Tampa Electric evaluate and calculate its incremental "post-9/11" security project costs according to the detailed guidelines provided in Order No. PSC-03-1461-FOF-EI filed in Docket No. 030001-EI on December 22, 2003?

A. Yes. The first test is to determine if the company has any O&M expenses for incremental security projects included in the Minimum Filing Requirements ("MFR") that established its current base rates and to remove any such expenses from the calculation of incremental expenses. None of Tampa Electric's post-9/11 increased security costs were included in MFRs that established its base rates as the company's last base rate proceeding was approved in 1993, before the terrorist attacks occurred. The second test is to identify any project costs that are reflected elsewhere in the company's base rates and remove them. Tampa Electric identified such project costs for security and credited the savings to the total incremental security expense. Finally, the third test is to determine if the project will result in any offsetting O&M savings and credit any savings to the project to reduce its total cost. Tampa Electric has evaluated its incremental security O&M expenses for related O&M savings and credited the savings against total incremental security O&M expenses. The calculation of incremental security O&M costs is shown on Exhibit No. ____ (CA-2), Document No. 2, page 4 of 6.

Q. Were Tampa Electric's base year "post-9/11" security costs adjusted for retail energy sales growth as required by Order No. PSC-03-1461-FOF-EI?

A. Yes. After adjusting the base year total by energy sales growth, the baseline that should be used to calculate 2008 incremental security costs is $2,293,026. The calculation of the baseline security O&M expense amount is shown on Exhibit No. ____ (CA-2), Document No. 2, page 4 of 6.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Regulatory Affairs in the Regulatory Affairs Department.

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy in 1995 from the University of South Florida in Tampa. I am a CPA in the State of Florida and have accumulated 13 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, budgeting and analysis, and cost recovery clause management. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I was promoted to Manager, Regulatory Affairs. My present responsibilities include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the projected wholesale incentive benchmark for January 2009 through December 2009. I will also describe significant events that affect the factors and provide an overview of the composite effect from the various cost recovery factors for 2009. Finally, my testimony addresses the projected capacity cost recovery factors that would become effective in May 2009 based on the company's rate design modification proposed in Docket No. 080317-EI.

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

A. Yes. Exhibit No. ____ (CA-3), consisting of three documents, was prepared under my direction and supervision. Document No. 1 is furnished as support for the projected capacity cost recovery factors utilizing existing retail class allocated cost of service and return studies as well as a proposed allocation methodology based on 12 Coincident Peak ("CP") and 25 percent Average Demand ("AD"). The proposed methodology is described in the direct testimony of William R. Ashburn submitted in Docket No. 080317-EI. Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, is comprised of Schedules E1 through E10 for January 2009 through December 2009 as well as Schedule H1 for January through December, 2006 through 2009. Document No. 3 provides a comparison of retail residential fuel revenues under the proposed inverted or tiered fuel rate and the traditional levelized fuel rate, which demonstrates that the tiered rate is revenue neutral.

Capacity Cost Recovery

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (CA-3), Document No. 1, pages 2 through 4. The capacity factors are annualized factors that are expected to apply for the period January through April 2009. Revised factors that illustrate the company's proposed rate design modifications are reflected on pages 5 through 7 of Document No. 1. Tampa Electric has requested an effective date of May 2009 for the change in capacity cost factors, coincident with the effective date of base rate modifications proposed in Docket No. 080317-EI.

Q. How will the proposed capacity cost recovery factors be impacted if the implementation date of the base rate adjustment is different than May 1, 2009?

A. The proposed capacity cost recovery factors starting January 1, 2009 are annualized factors. Therefore, those factors would remain in effect until the Commission approves the proposed changes submitted as part of Docket No. 080317-EI.

Q. What payments are included in Tampa Electric's capacity cost recovery factors?

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers excluding optional provision purchases for interruptible customers through the capacity cost recovery factors.

Q. Is Tampa Electric requesting recovery through the capacity clause for "post-9/11" incremental security costs?

A. No, the company is not requesting recovery of 2009 incremental security expenses as a result of the events of September 11, 2001 through the capacity cost recovery clause. As part of its request for a rate increase submitted in Docket No. 080317-EI, Tampa Electric proposes to move the incremental security expenses from the capacity cost recovery clause to base rates for recovery effective with May 2009 bills.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2009 through April 2009.

A.

Rate Schedule and Metering Voltage	**Capacity Cost Recovery Factor (cents per kWh)**
RS Secondary	0.580

GS and TS Secondary	0.547
GSD	
Secondary	0.429
Primary	0.425
Transmission	0.420
GSLD and SBF	
Secondary	0.377
Primary	0.373
Transmission	0.369
IS-1, IS-3, SBI-1, SBI-3	
Secondary	0.035
Primary	0.035
Transmission	0.034
SL-2, OL-1 and OL-3	
Secondary	0.089

These factors are shown in Exhibit No. ____ (CA-3), Document No. 1, page 4 of 8.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.467 cents per kWh compare to the factor for January 2008 through December 2008?

A. The proposed capacity cost recovery factor is 0.039 cents per kWh (or $0.39 per 1,000 kWh) higher than the average capacity cost recovery factor of 0.428 cents per kWh for the January 2008 through December 2008 period.

Q. Please describe the changes to the 2009 capacity cost recovery factors related to Tampa Electric's proposed rate design submitted in Docket No. 080317-EI.

A. As described in the direct testimony of William R. Ashburn filed in Docket No. 080317-EI on August 11, 2008, Tampa Electric proposes to combine all present demand rate schedules, which consist of General Service - Demand ("GSD"), General Service - Large Demand ("GSLD"), and Interruptible Service ("IS") into one new proposed GSD rate schedule. Additionally, the allocation of production demand costs according to the 12 CP and 1/13th AD methodology, where 1/13th or approximately eight percent of the demand costs is allocated on an energy basis, would be modified to 12 CP and 25 percent AD to better reflect cost causation, as shown in the company's 2009 Cost of Service Study. The new methodology helps ensure that the prices customers pay for electric service bear a reasonable relationship to the costs of providing that service.

Q. Are there any other proposed modifications that impact the capacity cost recovery factors?

A. Yes. It is more appropriate to recover capacity costs through a factor applied to billed kW demand for demand-measured customers because this recovery method will be consistent with the recovery of the production plant that otherwise would have been built. Therefore, Tampa Electric proposes to recover capacity costs from demand-measured customer classes on a dollar per kW basis rather than an energy basis.

Q. Has the Commission previously approved the recovery of capacity costs on a demand basis from demand-measured customers?

A. Yes. The Commission recognized the appropriateness of recovering capacity costs on a demand basis from demand measured customers in Order No. 25773 in Docket No. 910794-EQ. As a result of that order, Florida Power & Light began recovering capacity costs on a demand basis from demand-measured customers. Tampa Electric's proposed rate classes, including the new demand-based charges for GSD and Stand-by Firm ("SBF") customers, are reflected in the company's capacity cost recovery schedules effective from May 2009 through December 2009, as shown in Exhibit No. _____ (CA-3), Document No. 1, pages 5 through 7.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for May 2009 through December 2009.

A.

Rate Class and Metering Voltage	**Capacity Cost Recovery Factor Cents per kWh**	**Cents per kW**
RS Secondary	0.534	
GS and TS Secondary	0.514	
GSD, SBF Standard		
Secondary		1.73
Primary		1.71
Transmission		1.70
GSD Optional		
Secondary	0.410	
Primary	0.406	
Transmission	0.402	
LS1 Secondary	0.166	

These factors are shown in Exhibit No. _____ (CA-3), Document No. 1, page 7 of 8.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the year 2009?

A. The appropriate amount for the 2009 period is 6.766 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. _____ (CA-3), Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2009 through December 2009.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF penalty of $849,634, which is included in the calculation of the total fuel and purchased power cost recovery factors. Additionally, E1-C indicates the net true-up amount for the January 2008 through December 2008 period. The net true-up amount for this period is an under-recovery of $132,882,938.

Q. Please describe the information provided on Schedule E1-

D.

A. Schedule E1-D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2009 through December 2009. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering voltage level.

Q. Please describe the information provided on Schedule E1-E.

A. Schedule E1-E presents the standard, on-peak and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Is Tampa Electric proposing a tiered rate structure for the fuel and purchased power cost recovery factor applicable to residential customers?

A. Yes. Due to the recent increases in fuel commodity prices, Tampa Electric is proposing a tiered rate structure in order to encourage energy efficiency and conservation. As shown on Schedule E1-E, the rate structure will result in a two-tiered fuel charge where usage in excess of 1,000 kWh is priced one cent per kWh more than the charge for a customer's usage up to 1,000 kWh. The company believes that a higher fuel factor for usage above 1,000 kWh will result in a shift in usage patterns by reducing usage in higher priced periods and will also encourage increased energy efficiency and conservation.

Q. Will the tiered fuel rate structure affect rate classes other than the residential rate class?

A. No. The tiered rate structure is only applicable to the residential class. Additionally, as shown in Exhibit No. ____ (CA-3), Document No. 3, the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the traditional levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2009 through December 2009.

A.

Metering Voltage Level	Fuel Charge Factor (cents per kWh)
Secondary	6.766
Tier I (Up to 1,000 kWh)	6.416

Tier II (Over 1,000 kWh)	7.416	
Distribution Primary	6.698	
Transmission	6.631	
Lighting Service	6.485	
Distribution Secondary	8.290	(on-peak)
	6.116	(off-peak)
Distribution Primary	8.207	(on-peak)
	6.055	(off-peak)
Transmission	8.124	(on-peak)
	5.994	(off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 6.766 cents per kWh compare to the levelized fuel adjustment factor for the January 2008 through December 2008 period?

A. The proposed fuel charge factor is 1.547 cents per kWh (or $15.47 per 1,000 kWh) higher than the average fuel charge factor of 5.219 cents per kWh for the January 2008 through December 2008 period.

Q. Has Tampa Electric considered the impact of the higher fuel costs on customer bills?

A. Yes. On June 18, 2008, Tampa Electric notified its customers of the higher fuel costs the company was incurring and the impacts to rates as a result of the escalating costs. The company hopes that the six-month advance notice will allow customers to better plan and budget for the higher fuel costs in 2009. In addition, the company informed customers of the 12 new energy efficiency and conservation programs available to help customers minimize the impact of the price increase.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2009 fuel and purchased power and capacity cost recovery projections?

A. Yes. There are two significant events. These are 1) the company's wholesale purchases; and 2) Tampa Electric's new coal transportation agreements.

Q. Please describe the first event that affects the company's projection filing.

A. Tampa Electric entered into or continued several cost-effective purchase agreements with Hardee Power Partners, Progress Energy Florida, Reliant Energy, Pasco Cogen, Calpine Energy Services, L.P., and qualifying facilities. The purchases improve supply reliability for retail ratepayers in 2008 and 2009 at reasonable and prudent costs. The direct testimony of Tampa Electric witness Benjamin F. Smith, II describes the purchases and demonstrates that the costs associated with the purchased power agreements are prudent and appropriate for recovery through the fuel and purchased power and capacity cost recovery clauses.

Tampa Electric also intends to enter into purchase agreements to replace lost generation capacity during the planned 2009 Big Bend scrubber outage.

Q. Please describe the second event.

A. In June and August of 2008, Tampa Electric signed new fuel transportation agreements that take effect beginning January 1, 2009. Under the new contracts, the company will have the ability to ship solid fuels directly to Big Bend Station via rail or water routes. The testimony of Tampa Electric witness Joann T. Wehle describes the transportation contracts that are effective beginning January 1, 2009. As stated in witness Wehle's testimony, the expected impact of the new agreements is an approximate average increase of $14 million in solid fuel transportation costs over the existing transportation agreement.

Coal Transportation Agreement

Q. In procuring transportation contracts, has Tampa Electric complied with the requirements of Order No. PSC-04-0999-FOF-EI, issued October 12, 2004, in Docket No. 031033-EI?

A. Yes. Tampa Electric adopted the requirements of the aforementioned Order to ensure an open and competitive RFP process. The company established and followed a schedule for procuring transportation services that provided the required time for each stage in the process. Tampa Electric provided an advance copy of the RFP to Staff and parties to the fuel docket and met with them to discuss the RFP. Additionally, meetings were held to update the parties and bidders and address any questions or concerns related to the process.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2009?

A. The company's projected 2009 benchmark is $816,969, which is the three-year average of $757,156, $799,040 and $894,710 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2006, 2007 and 2008 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2009 from non-separated wholesale sales to exceed its 2009 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2009. Therefore, all sales margins below the $816,969 threshold will flow back to customers.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its capacity, fuel and purchased power, environmental and energy conservation cost recovery factors on a 1,000 kWh residential customer's bill?

A. The composite effect on a residential bill for 1,000 kWh is an increase of $14.06 beginning January 2009. These charges are shown in Exhibit No. ____ (CA-3), Document No. 2, on Schedule E10. Additionally, the composite effect on a residential bill for 1,000 kWh would increase

$10.24 beginning May 2009 if the proposed changes related to the company's request for an increase in base rates in Docket No. 080317-EI are approved.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with the first billing cycle for January 2009. Effective with the first billing cycle for May 2009, Tampa Electric proposes modified rates that reflect the company's new base rate charges and rate structure changes for Tampa Electric's commercial and industrial customers.

Q. Does this conclude your testimony?

A. Yes, it does.

CHAIRMAN CARTER: You may proceed.

MR. BEASLEY: Yes, sir. We tender Mr. Aldazabal for any questions you may have.

CHAIRMAN CARTER: Okay. Mr. McWhirter, you're recognized, sir. Oh, Mr. -- I'm sorry. Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. A, if you'd look at your originally filed Schedule E1 and your revised Schedule E1, do you have those handy?

A Yes, I do.

Q And you originally anticipated that your annual fuel costs would be $1,560,920,087 and then later on in October you reduced that to $1,350,000,000, and I anticipate that between September 2nd when you filed your original testimony and October 13th when you filed your revised testimony something happened that caused you to reduce your fuel, projected fuel cost by $210 million; is that correct?

A That's correct.

Q And can you give us a brief outline of what it is that happened in that period of time?

A Sure. Our original filing was based on a fuel forecast as of July 3rd or approximately the first week of July. When we filed our revised testimony, we updated that fuel forecast as of October 3rd. So it's a significant time differential between the, when we did the original filing. Even though we filed it on September 2nd, the forecast was quite a bit dated between that time and the October 3rd filing, revised filing.

Q Do you have any specific periods when you do reprojections of your fuel cost? Do you do it every month, every six months or what?

A We do a reprojection of our fuel cost every year.

Q Once a year?

A Yes, sir.

Q So if fuel costs go down between now and next August, there's nothing you will file to make a correction in your potential fuel factor?

A No, that's not the case. We monitor our costs on a monthly basis and we actually report on our A schedules where we are at any given point in time. In addition to that, we monitor where we are from a midcourse standpoint, whether we're plus or minus 10 percent over or underrecovered, and we would notify the Commission if that was the case.

Q And your monthly reports, as I understand it, you report the actual cost year to date compared to the projection that you made the previous October 3 in this instance; is that what you do on your monthly reports?

A That is what we file on a monthly basis, yes.

Q So if you're calculating a 10 percent adjustment, it would only be if your actual costs are 10 percent less than you projected, is that it?

A No, that's not the case. We actually do, do essentially a relook of what the costs are going to be at the end of the period in December. We have essentially an estimate of what we're going to end up at year end. So that, those costs would be incorporated into that plus or minus 10 percent number.

Q Do you, what do you file each month with the Commission with respect to the new projections?

A We file the actual results for that given month plus a year to date number comparing that number to what we originally had filed in the previous year's projection filing.

Q But in my previous question to you I asked you if you made periodic projections and your answer was yes. And this question is with respect to those periodic projections for the rest of the year, what do you file with the Commission concerning those numbers?

A We do not file any periodic projections with the Commission.

Q And so the next time we would see your projected revenue numbers is next August; is that correct?

A Assuming we did not go in for a midcourse adjustment, that would be the case.

Q And what would happen if your fuel costs turn out to be, annual fuel cost projections turn out to be 10 percent different? Do you feel any compulsion or is there any Commission order that requires you to file new projections?

A Yes. There is a Commission order that would require us to notify the Commission if that was the case.

Q And is that information available to the public before you file it with the Commission?

A I don't understand the question. What information?

Q Well, you make new projections each month.

A Uh-huh.

Q And if it's 10 percent more or less, you would notify the Commission. But if it -- you don't -- nothing is available to the general public until and unless you notify the Commission; is that correct?

A The general public would know what our actual results are at any given point in time but they wouldn't know what our projections are. That's correct.

Q Now on your E1 form that you filed in early September, it showed that your, at Line 34 it shows your rounded fuel factor per kilowatt hour, and that's, it's 7.808 and that's 7.8 cents per kilowatt hour. If I wanted to find out what that was per megawatt hour, would it be proper just to move the decimal over from 7.8 and make it $78.08 a megawatt hour? Is that the way you do it?

A That's correct.

Q Okay. So in September your fuel cost was anticipated to be $78.08 a megawatt hour and now a month later it turned out to be $67.54 a megawatt hour?

A No, that's not correct. The total fuel cost would be much further up. That would be actually Line 5, which is our cost of generated power. That bottom number encompasses purchased power as well as prior period true-ups.

Q So I see. What -- $54.56 is what it costs you to generate power; is that right?

A That's correct.

Q And then there are adders that bring it up to $67.54?

A Purchased power cost plus prior period true-ups. Yes.

Q Okay. I'd like to ask you, I noticed on Line 10 for your purchased power in September you estimated that the purchased power would cost you $81.38 and on October 13 it's still going to cost you $81.38, actually 39 cents. Do your purchased power contracts compel you to continue to pay that high price and the price doesn't go down with the fuel price?

A No, that's not the case. In our original filing the only difference between the original filing and the revised filing is that we updated the natural gas pricing on our cost of generation. We did not update the purchased power cost simply because of a time constraint. It's a very comprehensive process, and in order to adjust a purchased power cost we would have to redispatch the entire system and it wouldn't have allowed us plenty of time to do that.

Q I see. So do those contracts have a fuel component and a capacity component in them?

A The cost reflected on this would only be the fuel component.

Q I see. And if fuel cost goes down -- I represent some people with qualifying facilities. Even though fuel prices have gone down, you're still going to pay them $65.19?

A Well, keep in mind that qualifying facilities are based on as-available energy. So even if we were to adjust the natural gas pricing on those, it's based off of our Big Bend 4 coal units which are based off of a coal, not a natural gas price. So I don't think we're seeing the same kind of price variations on, on those contracts as we are in the natural gas contracts.

Q Well, I'd like to ask you about that. I noticed in one of your schedules you project that your coal cost this year is going to go up 36 percent. Can you give us some insight into why the coal cost is going to go up 36 percent?

A I wouldn't be the appropriate witness to answer that.

Q I see.

A I wouldn't know.

Q And you don't have any indication of why it is?

A No, sir.

Q Would that be Ms. Wehle?

A Yes, sir.

Q Okay. Go to your Schedule 7 that relates to these purchased power contracts. I'm not sure I totally understand what you're saying. You're going to pay $224 million this year to economy purchases and straight purchased power contracts and then qualifying facilities, and you say that those prices will change but you haven't changed them yet. Are they going to go up or go down?

A What I was trying to say is that we didn't adjust those prices when we did our revised filing because natural gas prices represent about, on those purchased power agreements they represent about $156 million of cost that could potentially be impacted if we were to adjust natural gas prices. But of that $156 million of impact, only 10 percent is what we adjusted natural gas prices by. So we're talking $15 million on the economy purchases, not the ones for cogen contracts. And then we would have to redispatch the whole system, so we just did not have the ability to do that in the, in the time period provided.

Q Well, let's go to this Schedule 7, if you don't mind. And am I correct that this year you're going to, you have a new purchased power contract that's been determined to be cost-effective and under that contract you're going to pay Pasco Cogen $110 a megawatt hour?

A I wouldn't be the witness to address purchased power agreements. That would be Witness Smith.

Q And Mr. Smith would be the one to do that?

A Yes, sir.

Q And in your filing you indicate that the fuel cost is $110 and the total cost is $110. Would it be fair to presume from that that in these contracts that are listed on Line 6 of your Schedule E1 that there are no capacity payments made to those contract customers, just a fuel payment?

A That's not necessarily the case. Line 6 could include some capacity payments for some of those agreements. Line 7 would not include any capacity payments.

Q So when you say in this Schedule 7 it has fuel cost and total cost, what you're telling me now is that total cost is not, that column is not accurate, that there is a capacity charge on top of what we have for the total cost?

A No. That column is accurate. That's a total for fuel adjustment. That is the fuel component of those agreements. The capacity component would be reflected on our capacity schedules.

Q And that capacity component is in your capacity charge?

A Yes, sir.

Q Do you know the philosophy that suggested that the fuel when it is only costing you $54.56 to generate electricity, why it's cost-effective to pay these people on average $117.83 a megawatt hour for fuel?

A Again, Witness Smith could better answer that question.

Q All right. Now in your original filing for natural gas, natural gas constitutes about what percentage of your total fuel cost?

A In my original filing?

Q Yeah. Well, the percentages will remain about the same, won't they?

A No, not necessarily because we only adjusted the natural gas pricing. Natural gas represented about 63 percent in the original filing.

Q I beg your pardon?

A 63 percent of our total fuel expense.

Q Is natural gas?

A Natural gas originally.

Q And you projected originally on your Schedule E5 that that would be $12.25 an MCF?

A I have $12.30 an MCF originally delivered.

Q And what do you project it on your new filing?

A I have $9.97 per MCF delivered.

Q Now does that cost have any charges in it other than the raw commodity cost for natural gas?

A Yes, it does. It includes the transportation to get the cost to our plants and it also includes the impacts of our hedges.

Q When the fuel charge -- when the price of natural gas goes up or goes down, does the transportation charge change correspondingly?

A The transportation charge would be a rate. So if the volume of the gas goes up or down, that transportation amount would change.

Q I see. So you don't have take-or-pay transportation agreements so that if you, if you sell less energy, if you sell less electricity, you can transport less coal or transport less gas and your transportation costs will go down along with the, the reduced sales; is that a correct statement?

A I'm not sure I understand the question. Can you repeat the question?

Q Well, the $9.97, I understand you said that that has two components. One is the raw gas cost and the second component is the transportation charge. So if the raw gas price were $7, we'd anticipate that, you anticipate the transportation, transportation cost is going to be $2, is that --

A No. There's a third component and it's the hedges. We've locked in some hedges and those costs are factored into that price as well.

Q I see. You, from time to time you lock in prices and that's what Ms. Wehle is going to talk about or has talked about and we've agreed that that's what you do and so forth.

A Yes, sir.

Q Okay. And in your most recent filing look at the schedule that shows the change in price of fuel from year to year. What is that, H10 or something like that? It would be Schedule H1, Page 31 of 31.

A Yes, I'm there.

Q Okay. And on Line 11 -- well, that's your generation. On Line 24 you anticipate that the price of natural gas is going to go up 8.8 percent over last year.

A Line 24?

Q That's what I'm looking at. But, you know, I make a lot of mistakes. You straighten me out.

A That's Btus burned. If we're looking at the price of natural gas, you want to go to Line 38.

Q I see. And you anticipate that there will be no increase, no 5.3 percent increase in 2009 over 2008?

A Well, what we're showing here is the actual estimated for 2008. And I'm actually showing a decrease --

Q Uh-huh.

A -- for 2009 versus actual estimated.

Q You think it'll decrease in 2009?

A Versus our actual estimated filing for 2008 that's what we're projecting, a decrease in natural gas.

MR. McWHIRTER: Thank you. That's all the questions I have and I tender the witness.

CHAIRMAN CARTER: Mr. Twomey.

MR. TWOMEY: Yes, sir, Mr. Chairman. Thank you.

CROSS EXAMINATION

BY MR. TWOMEY:

Q And good afternoon.

A Good afternoon.

Q I want to follow up just briefly, if I may, on some of the questions that Mr. McWhirter asked you to make sure I got the numbers correct.

My understanding is, is that you've testified that the company's original filing in this docket was based upon a July 3rd forecast; is that correct?

A Yes. That's correct.

Q Okay. And then --

A A forward, forward price forecast. Yes.

Q You call it what?

A A forward price forecast.

Q A forward price forecast?

A Yes, sir.

Q Okay. Is that, is that always for 12 months or is it for the remainder of the calendar year? How does that work?

A Well, July 3rd it would have been for a forward price forecast for the remaining portion of 2008 and all of 2009.

Q Okay. Now the, as I understand what you told Mr. McWhirter, since you have, and tell me if I'm correct in understanding this, since you have an obligation pursuant to Commission policy to advise the Commission of any change or over, underrecovery of 10 percent, at any given point in the year you track, you make a forecast every month whether you report it to anybody.

A We don't do a full-blown forecast, like I said before. It's a very comprehensive process. But we do track where we are on an actual basis and we have a general estimate of what we're going to end up at the end of the year.

Q So you do enough to make, apparently do enough to make yourself comfortable that you can advise the Commission at any given point on whether you're over or under 10 percent.

A Yes. And, in fact, we did that this year. We notified the Commission back in July that we anticipated being over 10 percent underrecovered at the end of 2008.

Q Okay. Now the -- thank you. Now the, from July 3rd to October 3rd is three months, it's a quarter; right?

A Approximately three months. Yes, sir.

Q The, so is that one you do -- do you do comprehensive or more comprehensive forecasts, forward forecasts on a quarterly basis?

A No. No. The only reason we did a very comprehensive forecast initially is we were anticipating the fuel filing coming up so we did a comprehensive forecast early on. What we did in our revised filing is we went in and adjusted our natural gas prices based on a more recent forward curve, but we didn't redispatch the entire system to adjust purchased power or the other components of the PROMOD process, which includes maintenance schedules and unit performance and all that.

Q Okay. And you told, as you discussed with Mr. McWhirter, if I heard you correctly, the, the difference in the forecast price for natural gas resulted in a, a drop in the total requested for 2009 of some $211 million.

A That -- both the combination of 2008 and 2009.

Q Reduced gas prices for the remainder of this year plus what you forecast it to be for all of 2009.

A Yes, sir.

Q $211 million.

A Yes, sir.

Q Which is about 13.5 percent.

A Of what?

Q Of the base price you had of $1.561 billion originally.

A Subject to check, yes.

Q Okay. Now so -- and you said to Mr. McWhirter that -- did you tell Mr. McWhirter your natural gas percentage of the cost was 53 percent or 63 percent?

A 60 -- I have to recalculate it. It was 60 something percent.

Q Okay. But it was 60, not 50?

A Yeah. It was 60 something percent.

Q I'm almost as hard of hearing as he is.

The -- well, what I wanted to ask you is the, you made your supplemental filing October 13 because over the course of, of just three months you forecast changes in the price of natural gas sufficient to bring your total fuel bill for the remainder of 2008 and 2009 down almost 14 percent for a total of some $210, $211 million; correct?

A That's correct. We were also able to adjust our actual -- we had three additional months of actual results. So incorporating that into the reduction as well.

Q Okay. Now do you have any confidence that gas won't reduce more or even substantially more in the remainder of this year? We have another, another quarter to go; right?

A Yes.

Q Another two months, but another quarter from your last forecast.

A We actually looked at our forecast and our commodity price is in line with what we have in our October 13th filing, the pure commodity price. There's not a significant difference there. And in fact the cooler months are upcoming, so our expectation is that natural gas prices, if anything, could possibly go up with the cooler months coming, so.

Q So you think, you think the decreases that we are going to see from the middle of this year until the next part, the end of next year, we've experienced them in your best judgment?

A That's a much better question for Witness Wehle. It's a forecast question.

Q Okay.

A But what I'm trying to say is that our commodity price that we have embedded in our revised filing is in line with what exists today as far as on a forward price basis.

MR. TWOMEY: Okay. Very good. Thank you. That's all.

CHAIRMAN CARTER: Thank you. Commissioners, I'm going to go to the staff before coming back to the bench.

Staff, you're recognized.

MR. YOUNG: No questions.

CHAIRMAN CARTER: Commissioner Skop, you're recognized.

COMMISSIONER SKOP: Thank you, Mr. Chairman. Just a quick question. I thought, in the lengthy discussion I thought I heard the witness state that transport costs may fluctuate with gas hedges if volumes change. And did I hear that correctly?

THE WITNESS: I guess what I was trying to say is that there's a fixed rate component on our natural gas transportation agreements. Even though the fixed rate doesn't change, depending on the volume, the dollar amount, the fuel expense could change, so.

COMMISSIONER SKOP: Thank you for that clarification.

THE WITNESS: Sure.

CHAIRMAN CARTER: Thank you. Commissioners, anything further from the bench? Okay then.

MR. BEASLEY: I have no redirect, and I would like to move the admission of Exhibits 44, 45 and 46 for Mr. Aldazabal.

CHAIRMAN CARTER: Hang on one second. Any objection to the exhibits? Commissioners, that would be Exhibits 44 through 46. Without objection, show it done.

(Exhibits 44 through 46 admitted into the record.)

Anything further from this witness from any of the parties?

MR. McWHIRTER: I'd like to ask a couple of questions of Mr. Smith on the cost-effectiveness of these contracts.

CHAIRMAN CARTER: Mr. Smith is, he's coming up next.

MR. McWHIRTER: Okay.

CHAIRMAN CARTER: We're just -- I got you though. We'll bring Mr. Smith on in a minute. Let's deal with Mr. -- I'm going to give a shot at this, Aldazabal.

THE WITNESS: That's correct.

CHAIRMAN CARTER: Let's don't do nothing else today. (Laughter.) You're only entitled to one of those a day.

So you may be excused, sir.

MR. BEASLEY: Call Mr. Smith.

CHAIRMAN CARTER: Mr. Smith. And while Mr. Smith is coming here, staff, I'm looking at my -- and, Commissioners, as you look at your witness list, I don't see -- I guess we'll have to modify, put Mr. Smith's name on there. I don't see anything down for him other than on our pretrial -- no exhibits? Okay. Good. All righty. You're recognized.

MR. BEASLEY: Mr. Chairman, his last name is Smith.

(Laughter.)

BENJAMIN SMITH

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

DIRECT EXAMINATION

BY MR. BEASLEY:

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

A Yes. My name is Benjamin Smith. My business address is 702 North Franklin Street, Tampa, Florida 33602, and I am Manager of Strategic Fuels and Power Services for Tampa Electric Company.

Q Mr. Smith, did you prepare and submit in this proceeding a document entitled Prepared Direct Testimony of Benjamin F. Smith, which is a projection testimony for January through December 2009 filed on September 2nd, 2008?

A Yes, I did.

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

A Yes, they would.

MR. BEASLEY: And I would ask that Mr. Smith's testimony be inserted into the record as though read.

CHAIRMAN CARTER: The prefiled testimony of Mr. Smith will be entered into the record as though read.

MR. BEASLEY: Thank you.

TAMPA ELECTRIC COMPANY
DOCKET NO. 080001-EI
FILED: 9/2/08

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH, II

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

A. My name is Benjamin F. Smith, II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the Fuel Services and Systems group within the Fuels Management Department.

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

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida and am a registered Professional Engineer within the State of Florida. I joined Tampa Electric in 1990 as a cooperative education student. During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager of Strategic Fuels and Power Services in the Fuel Services and Systems group. My responsibilities are to evaluate short-term and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale contract structure and help evaluate the processes used to value wholesale power opportunities. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers and other wholesale generators.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I testified before this Florida Public Service Commission ("Commission") in Docket Nos. 030001-EI and 040001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

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

A. The purpose of my testimony is to provide a description of Tampa Electric's purchased power agreements that the company has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe Tampa Electric's purchased power strategy for mitigating price and supply-side risk, while providing customers with a reliable supply of economically priced purchased power.

Q. Please describe the efforts Tampa Electric makes to ensure that its wholesale purchases and sales activities are conducted in a reasonable and prudent manner.

A. Tampa Electric evaluates potential purchased power needs and sale opportunities by analyzing the expected available amounts of generation and the power required to meet the projected demand and energy of its customers. Purchases are made to achieve reserve margin requirements, to meet customers' demand and energy needs, to supplement generation during unit outages and for economical purposes. When there is a purchased power need, the company aggressively polls the marketplace for wholesale capacity or energy, searching for reliable supplies at the best possible price from creditworthy counterparties.

Conversely, when there is a sales opportunity, the company offers profitable wholesale capacity or energy products to creditworthy counterparties. The company has wholesale power purchase and sale transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's wholesale purchase and sale activities are conducted in a reasonable and prudent manner.

Q. Has Tampa Electric reasonably managed its wholesale power purchases and sales for the benefit of its retail customers?

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order, No. PSC-97-0262-FOF-EI, issued in Docket No. 970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs.

The company monitors its contractual rights with purchased power suppliers as well as with entities to which wholesale power is sold to detect and prevent any breach of the company's contractual rights. Also, Tampa Electric continually strives to improve its knowledge of wholesale power markets and the available opportunities within the marketplace. The company uses this knowledge to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power is available on Tampa Electric's system and market conditions allow.

Q. Please describe Tampa Electric's 2008 wholesale energy purchases.

A. Tampa Electric assessed the wholesale power market and entered into short-term and long-term purchases based on price and availability of supply. Approximately 18 percent of the expected energy needs for 2008 will be met using purchased power. This purchased power energy includes economy purchases and existing firm purchased power agreements with Hardee Power Partners, Calpine and qualifying facilities. The company's purchases also include a 25 to 125 MW firm system average purchase from Progress Energy Florida and a 158 MW firm peaking purchase from Reliant.

The Calpine purchase is a 170 MW peaking purchase that began in May 2006 and continues through April 2011. As described in my September 2005 testimony and approved by the Commission in Docket No. 050001-EI, this purchase is from Calpine's natural gas-fired facilities in Auburndale, Florida and was entered into to meet Tampa Electric's peaking system needs.

As described in my September 2007 testimony and approved by the Commission in Docket No. 070001-EI, the purchase from Progress Energy Florida was 50 MW from January 2006 through March 2007 that increased to 75 MW for the period of April through November 2007. In a September 2007 amendment that followed my testimony filing, this purchase was increased again and extended to a total of 100 MW for the period December 2007 through March 2008. This purchase amendment provides an estimated $1.6 million in savings to customers. In November 2007, the purchase was amended once again to include an additional 25 MW for the period December 2007 through December 2008. The second purchase amendment provides an estimated $1.3 million in savings to customers. Lastly, in March 2008, the purchase was amended once more to include an additional 100 MW for the period April through May 2008. This third purchase amendment provides an estimated $3.8 million in savings to customers, resulting in a cumulative $6.7 million in estimated savings to customers for the three Progress Energy Florida purchase amendments.

While negotiating an agreement with the winning bidder, Reliant Energy, to fulfill Tampa Electric's 2009 peaking power Request for Proposals ("RFP"), the company became aware of a 2008 reserve margin need and negotiated an additional peaking purchase contract with Reliant under the same terms.

All of these purchases help reduce price volatility. They were also reliable sources of power during the Big Bend Unit 3 SCR installation outage, which began November 2007, and the 2008 spring planned maintenance outages of Bayside Unit 1 and Polk Unit 1. Additionally, the Reliant purchase continues to reduce supply and price volatility risk through the summer peak loads and into the fall planned maintenance season, which includes the start of the Big Bend Unit 2 SCR installation outage.

With the exception of the April through May 2008 Progress Energy Florida purchase, which was not signed in time to be included, Tampa Electric identifies all of these purchases in Chapter 4, "Forecast of Facilities Requirements", of its 2008 Ten Year Site Plan, filed April 1, 2008.

Q. Has Tampa Electric entered into any other wholesale energy purchases?

A. Yes. As described in my September 2007 testimony and approved by the Commission in Docket No. 070001-EI, Tampa Electric finalized the purchase of 121 MW of firm intermediate, natural-gas fired capacity with Pasco Cogen for the period January 2009 through December 2018. This purchase was finalized in August 2007 with an estimated savings to customers of $13 million over the life of the contract. However, since my 2007 testimony, the savings to customers have been further maximized through the company's purchase of the Union Hall Substation that services Pasco Cogen. This purchase allows for a direct connection to Tampa Electric, which eliminates the need to pay for an estimated $17 million in transmission wheeling services through Progress Energy Florida. The elimination of this wheeling cost results in a direct benefit to customers, increasing their estimated savings from $13 million to $30 million over the life of the contract.

As a result of Tampa Electric's Request for Proposals ("RFP") for peaking power beginning in 2009, a 158 MW Reliant Energy purchase was secured to meet the company's 20 percent firm reserve margin requirement. This firm purchase was finalized in December 2007 and begins January 1, 2009 and continues through May 31, 2012. The Reliant purchase was the most cost-effective option resulting from the RFP.

Tampa Electric also identified the Pasco Cogen and Reliant purchases in its Ten Year Site Plan filed April 1, 2008.

For 2009, the company expects to meet approximately 13 percent of its customers' energy needs through purchased power, which includes economy purchases and the existing firm purchased power agreements with Hardee Power Partners, Calpine, Reliant, Pasco Cogen and qualifying facilities. All of these purchases provide supply reliability and help reduce price volatility.

Lastly, Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during its spring and fall generation maintenance periods and peak periods. This purchasing strategy provides a reasonable and diversified approach to serving customers.

Q. Does Tampa Electric plan to enter into any other new purchased power agreements during its upcoming Big Bend Station SCR installation outages?

A. With the exception of its previously mentioned purchases, Tampa Electric has not made purchases for the upcoming SCR installation outages on Big Bend Units 1 and 2 at this time. However, the company continually monitors and engages the marketplace for power purchase opportunities and will evaluate the economics of potential forward purchases during the outages to reduce the overall cost to customers. The SCR installation outages for Big Bend Units 2 and 1 are scheduled to begin December 2008 and November 2009, respectively. The outages are projected to last approximately four months each.

Q. Does Tampa Electric engage in physical or financial hedging of its wholesale energy transactions to mitigate wholesale energy price volatility?

A. Physical and financial hedges can provide measurable market price volatility protection. Tampa Electric purchases physical wholesale products. The company has not engaged in financial hedging for wholesale transactions because the availability of financial instruments within the Florida market is limited. The Florida wholesale power market currently operates through bilateral contracts between various counterparties, and there is not a Florida trading hub where standard financial transactions can occur with enough volume to create a liquid market. Due to this lack of liquidity, the appropriate financial instruments to meet the company's needs do not currently exist. Tampa Electric has not purchased any wholesale energy derivatives, but the company does employ a diversified power supply strategy, which includes self-generation and short-term and long-term capacity and energy purchases. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

Q. Does Tampa Electric's risk management strategy for power transactions adequately mitigate price risk for purchased power for 2008?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For example, the 170 MW Calpine purchase and the 158 MW purchase from Reliant in 2008 are reliable, cost-based call options on peaking power. Likewise, the Progress Energy Florida purchase is a cost-based call option on system average energy. All of these purchases serve as both a physical hedge and reliable source of economical power in 2008. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by supply and the volatility of natural gas prices.

Mitigating price risk is a dynamic process, and Tampa Electric continually evaluates its options in light of changing circumstances and new opportunities. Tampa Electric also strives to maintain an optimum level and mix of short- and long-term capacity and energy purchases to augment the company's own generation for the year 2008 and beyond.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchased power supplies during major weather related events such a hurricane?

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions during major weather related events. The strategy includes monitoring storm activity; evaluating the impact of the storm on the wholesale power market; purchasing power on the forward market for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing the seller's fuel sources and dual fuel capabilities; and focusing on fuel-diversified purchases. Notably, the recently acquired purchases from Reliant and Pasco Cogen are dual fuel resources, having both natural gas and oil capability, which enhances supply reliability during a potential hurricane-related disruption in natural gas supply. Absent the threat of a hurricane, and for all other months of the year, the company continues its strategy of evaluating economic combinations of short- and long-term purchase opportunities identified in the marketplace..

Q. Please describe Tampa Electric's wholesale energy sales for 2008 and 2009.

A. Tampa Electric entered into various non-firm, non-separated wholesale sales in 2008. The gains from the non-separated sales are returned to customers through the fuel clause, up to the three-year rolling average threshold of $811,478. In 2008, the company is expected to exceed this threshold by $111,106, of which customers receive 80 percent, or $88,885, of this amount. The remaining 20 percent is company revenue in accordance with Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No. 010283-EI.

In 2009, other than its pre-existing separated sales, Tampa Electric has made no separated sales for 2009. However, the company anticipates its gains from non-separated wholesale sales in 2009 to be $718,000, of which 100 percent would flow back to customers since it is less than the projected threshold of $816,969.

Q. Please summarize your testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and those efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and short-term and long-term power purchases. The company purchases in both the physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. It also enters into wholesale sales that benefit customers. Tampa Electric does not purchase wholesale energy derivatives in the developing Florida wholesale power market due to a lack of financial instruments appropriate for the company's operations. It does, however, employ a diversified power supply strategy to mitigate price and supply risks.

Q. Does this conclude your testimony?

A. Yes.

MR. BEASLEY: Mr. Smith is available for the questions that you may have and Mr. McWhirter.

CHAIRMAN CARTER: Thank you. Mr. Wright?

MR. WRIGHT: No questions, Mr. Chairman. Thank you.

CHAIRMAN CARTER: Mr. McWhirter, you're recognized, sir.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. Smith, you were in the room and heard the questions that I asked Mr. A about the, the purchased power contracts. And he stated that, if I'm stating it correctly, and if I'm not, correct me, he said that when you made the adjusted schedule, you reduced the cost of generation but you didn't reduce the fuel cost that's attributable to purchased power, and I guess that's because you haven't gotten around to it. Do you know what that reduction in cost might be of that 200 and something million dollars that's designated for purchased power, $224 million?

A And that was on a -- which schedule was that on?

Q On Schedule E1, Line 10, purchased power cost is $224 million.

A I'm getting to the schedule.

Q It's Schedule E1 to Mr. A's testimony.

A Do you have a Bate stamp page on that?

Q It's Page 29.

CHAIRMAN CARTER: Staff, can we help out here? It may have changed with our numbering sequence here. Let's -- have we got a copy of that that we can get to him?

Thank you, Mr. Twomey.

THE WITNESS: Line 10, $224 million, that number?

BY MR. McWHIRTER:

Q Yes. And he said that the other fuel costs are going down but you hadn't gotten around to reexamining those costs. Can you tell us what the status of the reexamination is on your purchased power contract?

A I can't tell you exactly what the adjustment would be, but relative to specific deals -- for example, you mentioned a Pasco deal --

Q Yes, sir.

A -- that was shown at about $110 per megawatt hour.

Q Yes, sir.

A That deal is a cost-based deal, which means it's at a fixed heat rate times the price of natural gas. So to the extent that the price of natural gas itself, that commodity was reduced, then the cost of that purchased power agreement would also be reduced.

Q Well, your cost of generated power has gone down something like, what, 13 to 15 percent? Can we fairly assume that the $224 million will go down some 13 to 15 percent also?

A I can't make that, that assumption.

Q But you do know that it's going to go down for 2009.

A For the contracts that we have that are natural gas based --

Q Yes, sir.

A -- yes, if the commodity price were to go down, the fuel costs associated with those contracts would go down as well.

Q Okay. But you don't know how much but we do know they're going to go down. And in your testimony you haven't designated that amount. When, when will we get that information?

A For my testimony I do identify a percentage of energy that we expect to come from purchased power and the deals that we've entered into and the savings associated with those deals, but I do not determine the specific fuel costs associated with a particular deal.

Q All right. Let's go to Schedule E7 attached to Mr. Aldazabal's testimony.

MR. BEASLEY: Do you have a Bate stamp page number?

BY MR. McWHIRTER:

Q It's on Page 26 of 31.

A I believe I have it.

Q Page 27 of 31. 27 is more appropriate. And if you go to the bottom, you show your purchased power contracts that will constitute $77 million or close to $78 million. And it has a fuel, average fuel cost of $131.71 per megawatt hour and a total cost. And he said that that really wasn't the total cost, that there was another capacity charge on top of that. Is that correct?

A These contracts do have a capacity charge component. Yes.

Q And you're the person that presented testimony on why this contract is cost-effective. Can you give us the criteria you used in making that determination?

A Sure. When we evaluate whether or not a contract like this is cost-effective, we basically do an analysis in our system dispatch models where we see what our system costs are going to be before we make this purchase and then we actually add the purchase in and we simulate what our system costs will be with the purchase. That gives us a difference in cost. And to the extent that that difference in cost which we call savings is greater than the actual cost of doing the deal, then the deal shows savings to us and it's a good deal.

Q Are you obligated to buy a certain amount of energy from the new contract, the Pasco Cogen contract?

A The Pasco Cogen contract is a call option, which means that we utilize that energy when it's economic to do so. It's not a must take contract where we're obligated to take a certain amount of energy. But when it's economic to do so, we dispatch that resource into our system.

Q Can you give me -- and that contract has a capacity component. Do you pay the capacity component even if you buy no electricity from that provider?

A Yes. It's a firm contract and the seller reserves that capacity solely for us. So the capacity charge is to make sure that stays reserved for only Tampa Electric Company.

Q Okay. And what, what's the amount of that capacity?

A That's confidential. The capacity payment or the capacity itself?

Q The capacity that you purchased.

A It's about 130 megawatts.

Q So it's a pretty big supply. And do you know what the amount of the payment is?

A Off the top of my head I don't know the exact payment value for capacity.

Q But that would be in addition to the $77 million you paid for the fuel.

A The capacity doesn't show up in the fuel component here.

Q And you reached the conclusion that that contract was cost-effective because you put it into a computer model and it popped out that that was better than what you would do otherwise?

A It showed savings both covering the cost of fuel as well as the capacity payment. Yes.

Q And what was the alternative that you measured it against? If you weren't buying from this provider, you'd be buying from, what, the open market?

A Well, there, there's the alternative of buying from the open market, yes. But there's also the alternative of running our more expensive resources.

Q But you've got a lot of leeway there when your most expensive resource is $57 a megawatt hour and this is $110 a megawatt hour.

A Once again, Mr. McWhirter and Commissioners, this is a cost-based contract and it's calculated based on a fixed heat rate times the price of natural gas.

Witness Aldazabal mentioned that when they reprojected, they did not go back and reproject the cost of this purchased power. So to the extent that the price of natural gas is decreased from what these were based on, instead of seeing a $110 per megawatt hour price, for example, you would see something less. So to compare this number to his reprojection are comparing two different things based on two different gas prices.

Q Well, you're not paying these people $10, you're paying them $110 a megawatt hour.

A Correct. The $110 per megawatt hour is based on the price of natural gas in the original projection as well as being based on the seasons of times that we utilize this purchase. Once again, this is a call option that's dispatchable when it's economic to do so. Since it is a call option of natural gas prices, it's typically going to be utilized most during the summer when the prices are projected to be higher for natural gas, when the loads are projected to be higher on our system. So the cost is going to be substantially greater on this when natural gas prices are higher.

Q Can you give us some insight into what you're paying for natural gas during the summer of 2008?

A This summer of 2008, I do not know what the gas prices are for summer of 2008.

Q When, when you file schedules that show your month-to-month price and those schedules show something like $10 a megawatt hour for gas that you're purchasing, it seems kind of unusual that your computer would kick out a price of $110 as being more economical than the average price.

A I can give you an example for --

Q Okay.

A -- what you're, what you're asking. Remember, these are for the year 2009. And in looking at what the gas prices were in the original projection, those gas prices were double-digit gas prices. We're talking, say, $12 per megawatt hour, $12 per MMBtu or $14 per MMBtu.

Now without actually giving away the terms of our deal, let's just assume that the heat rate is a 10,000 heat rate for a nice round number. A 10,000 heat rate resource times a $14 per MMBtu gas price is a $140 resource, and that's what generates the type of numbers that you see here. So to the extent that the price of natural gas is in those double digits, then you will end up with a price in the $100 range. To the extent that the price of natural gas is $7, then you end up with a $70 resource. Once again, this is a cost-based contract based on a fixed heat rate times the price of natural gas at the time it's dispatched.

Q I see. So heat rate comes into play. Can you divulge what the heat rate is on this contract?

A That's confidential.

Q And can you tell us what the heat rate is in your GPIF files for your gas turbines and your combined cycle plants?

A I can tell you for our Bayside resource, for example, which is our large combined cycle, the heat rate is in the 7,000 range.

Q I see. So that heat rate is 30 percent better than you contracted for; is that right?

A It's an intermediate gasification, intermediate combined cycle. It's a different resource and it is more efficient than a peaking resource.

Q How long did you lock in this new contract that you're seeking approval for in this proceeding?

A The Pasco Cogen contract begins January, January 2009 and it continues through 2017. So it's a ten-year contract.

Q And so if the Commission approves this contract at this time, it's locked in for the next ten years and it can't do anything about it?

A Well, the Pasco Cogen, as I mentioned in my testimony, the Pasco Cogen contract has significant savings to customers. It has $30 million of projected savings. So having a contract such as this seems to me is a beneficial contract to have.

Q I would tend to agree if you had $30 million in savings, but I haven't seen any testimony that indicates what those savings are because you show that the heat rate is substantially greater than the heat rate for a combined cycle and there must be something else at play that would give us some insight into it. What is that?

A I'm looking in my testimony. On Page 8 and 9 in my testimony is where I identify the $30 million of savings for Pasco Cogen. And those savings for Pasco Cogen are $13 million of savings utilizing an analysis as I described before both with it in our system and without, with an additional $17 million of savings from avoided transmission costs since we've since purchased a substation that allows us to serve, get, get that power directly instead of paying transmission wheeling costs.

Q Now that substation, you purchased it. Did that go into your base rates or are you asking to put that substation in your fuel charge?

A I don't know where that cost would go. I'm not the right witness for that.

Q Would it be part of the capacity component of this charge?

A I don't know where the company would put the purchase of the substation.

Q Does -- when you make an investment in a substation, do you get a return on that investment?

A I'm not, I'm not familiar with what the company would do in that case.

MR. McWHIRTER: I have no further questions of this witness.

CHAIRMAN CARTER: Thank you. Mr. Twomey.

MR. TWOMEY: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. TWOMEY:

Q And good afternoon, Mr. Smith. Who would be the right witness to answer Mr. McWhirter's questions, do you know?

A I do not know.

Q Okay. Fine. Now the -- I just have a number of questions to ask that are related to what Mr. McWhirter asked you and they're related to the, the projections for, primarily for 2009. I think it has to be 2009 for this Pasco Cogen contract. And I don't want to ask you any questions at all like Mr. McWhirter did in part on the prudency of the underlying contract. Okay?

It struck me from your early conversation with him that there is an issue about the correctness of the projections that, of the, the costs that are included with the Pasco Cogen contract independent of the, the prudency of the underlying contract, and that those, those questions relate to the fact that, if I heard you correctly, that purchased power agreement is based in part on the, the heat rate of the unit times the price of natural gas; right?

A Correct.

Q Now as I understand it further, the company, when it realized that the price of natural gas from whatever the October 3rd forecast, that the price of natural gas was going to go down some, by my calculation, 13.5 percent or in that neighborhood, the company recognized the importance apparently of keeping the customer rates down and went ahead and modified or revised its filings by some $210 million, $211 million; right? But that, that revision was based solely on the, I guess the, what I would call the gross purchase of natural gas for your own units.

What I think Mr. McWhirter was asking about and remains unresolved yet is that there are other purchases of natural gas for -- there's pricing, other pricing for natural gas in 2009 as relates to this Pasco Cogen contract which you haven't yet taken time to modify for what you know to be a reduction in the price of gas; is that correct?

A To my knowledge, we have not reprojected the price of gas for these purchased power agreements.

Q Okay. My question is this. The -- you have, you have witnesses that have provided sworn testimony that they believe within the confines of whatever your projection methodology ranges are that the price of natural gas for your own use is going to go down the last quarter of this year and it's going to be down substantially for all of 2009. That's your company's projections.

What, what would be wrong since that appears to be the best information you have of using those same gas prices to modify and thereby reduce the amount of money you want to get from your customers in 2009 related to the Pasco Cogen contract?

A Once again, with a decrease in the price of natural gas, the affected fuel prices for these purchased power agreements would go down. As far as why the company did not go through and adjust the prices for purchased power, I am not the correct witness to answer that. I would say that the price of natural gas would affect the price of these purchased power agreements. If that price of natural gas were lower, then the price of these resources would be lower. If it were higher, then the price of these resources would be higher.

Q Yes, sir, Mr. Smith. And I'm just, I won't belabor this. I'll say this and I'll stop. I'm trying to, I'm trying to understand why we went ahead -- maybe it's because of time constraints, I would accept that -- we went ahead, the company recognized a substantial decrease in the price of natural gas for your own consumption and reduced the fuel adjustment charge requested going forward. That makes sense.

For whatever reason, the press of time or whatever, there is this Pasco Cogen contract and maybe others that also you're asking for recovery through your customers for the year 2009; right?

A Correct.

Q And a key part of the pricing of that and the amounts you have in your request for 2009 is based upon the price of natural gas, but you're apparently using the old price, not the new price. So what I'm trying to ask of you or whatever witness in the company is if there's a potential additional savings to the customer and a reduction in your fuel adjustment charge by applying the new projected cost of natural gas to the Pasco Cogen contract, shouldn't we be doing that as well?

A Once again, if the price of natural gas were less, then the price of these purchased power agreements would be less. I do not know why the company didn't reproject purchased power when it did its reprojection filing.

MR. TWOMEY: Okay. Thank you. I appreciate your help.

CHAIRMAN CARTER: Thank you. Commissioners, I'm going to go to staff before coming to the bench.

Staff, you're recognized.

MR. YOUNG: No questions.

CHAIRMAN CARTER: Commissioners, anything further? Okay then.

MR. BEASLEY: We have no redirect, sir. And the, Mr. Smith did not sponsor an exhibit, so there are no exhibits to move.

CHAIRMAN CARTER: Okay. Anything -- nothing further for this witness? Thank you, Mr. Smith. Have a great day.

Staff, there were no exhibits for Mr. Smith, so.

MS. BENNETT: No. We've got the testimony entered and there were no exhibits, so I think we're finished with TECO.

CHAIRMAN CARTER: Did we cover all of the stipulated witnesses, et cetera, for TECO, all matters?

MR. BEASLEY: Yes, sir, we did, and we appreciate your indulgence.

CHAIRMAN CARTER: Thank you. Commissioners, my plan was -- you know, I'm reluctant to go forward with my plan and here's why, is that Mr. Burgess has a preliminary matter when we get into the FPL case and I really would want to give him the complete time that he needs to make that, as well as give the company an opportunity to be heard on that. But it wouldn't do Mr. Burgess justice for us to start and then have to stop because I did promise staff I'd give them an opportunity to go and exercise their franchise on a day like today. So, Mr. Burgess, if that would help you -- what's your take on that?

MR. BURGESS: I appreciate that, Commissioner. I think that would work better to go ahead and start anew.

CHAIRMAN CARTER: Okay. Let's do that, Commissioners. We've, we've completed our task. And, staff, one final -- yes, ma'am, Commissioner Argenziano.

COMMISSIONER ARGENZIANO: Is that legal talk for staff going to vote?

(Laughter.)

CHAIRMAN CARTER: Yes. Yes, ma'am, it is.

But, staff, we have completed information from Progress, from FPUC, from Gulf and TECO, and what we'll do tomorrow morning, we'll start with -- Mr. Burgess has a preliminary matter in the FPL case and we'll start there. And, Commissioners, also there is, before we complete this task tomorrow, Commissioner Argenziano, the issue that was raised, we'll deal with that at that point in time before we have a final disposition. And with that, everybody, we are on recess until tomorrow at 9:30.

(Hearing recessed at 4:31 p.m., and will resume at 9:30 a.m. on November 5, 2008.)

(Transcript continues in sequence with Volume 4.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, 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 7th day of November, 2008.

Linda Boles

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