BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 030001-EI

In the Matter of

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

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VOLUME 5

Pages 692 through 807

PROCEEDINGS: HEARING

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

DATE: Wednesday, November 12, 2003

TIME: Commenced at 9:00 a.m.
Concluded at 6:35 p.m.

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

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

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
28	JDJ-1	696	763
29	JDJ-2	708	763
30	JDJ-3	718	763
31	SLB-1 through SLB-8	766	

P R O C E E D I N G S

(Transcript continues in sequence from Volume 4.)

MR. BEASLEY: Call Ms. Jordan.

CHAIRMAN JABER: Mr. Beasley, you're going to have revised testimony for Ms. Jordan as well; right?

What is -- yesterday I found on the bench here, it looks like revised testimony, rebuttal testimony of Denise Jordan. We can take that up during rebuttal, but I don't know if this was an extra copy I received or something I should -- you intend for us to substitute.

MR. BEASLEY: Okay. If we did -- we did submit revised rebuttal testimony. And if you would like to hold that until we get to it, we'd be happy to do that.

CHAIRMAN JABER: Okay.

J. DENISE JORDAN

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 Would you please state your name, your business address and your position with Tampa Electric Company?

A My name is J. Denise Jordan. My business address is 702 North Franklin Street, Tampa, Florida 33602. My title is director of rates and planning.

Q Ms. Jordan, did you prepare and submit in this proceeding a document entitled, "Final True-up Testimony of J. Denise Jordan" filed April 1, 2003?

A Yes, I did.

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

A No, I do not.

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

A Yes.

MR. BEASLEY: I'd ask that Ms. Jordan's final true-up testimony be inserted into the record as though read.

CHAIRMAN JABER: The prefiled testimony of Denise Jordan dated April 1st shall be inserted into the record as though read.

BY MR. BEASLEY:

Q Ms. Jordan, did you have prepared under your direction and supervision the Exhibit JDJ-1 that accompanied that April 1 filing?

A Yes, I did.

MR. BEASLEY: I'd ask that JDJ-1 be marked for identification?

CHAIRMAN JABER: JDJ-1 will be marked as Exhibit 28.

(Exhibit Number 28 marked for identification.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
FILED : 04/01/03

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. DENISE JORDAN

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

A. My name is J. Denise Jordan. 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 Director, Rates and Planning in the Regulatory Affairs Department.

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

A. I received a Bachelor of Mechanical Engineering degree in 1987 from Georgia Institute of Technology in Atlanta, Georgia. Prior to joining Tampa Electric, I accumulated 13 years of electric utility experience working in the areas of rate design and administration, demand-side management implementation, commercial and industrial account management, customer service and marketing. In April 2000, I joined Tampa Electric as Manager, Electric

Regulatory Affairs. In February 2001, I was promoted to Director, Rates and Planning. My present responsibilities include the areas of fuel and purchased power cost recovery filings, capacity cost recovery filings, environmental cost recovery filings, strategic planning and energy and rate design issues and analyses.

Q. What is 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 and approval, the net true-up amounts for the period from January 2002 through December 2002 for both the Fuel and Purchased Power Cost Recovery and the Capacity Cost Recovery Clauses. I also present the wholesale incentive benchmark for January 2003 through December 2003 as well as the actual incremental security alert and hedging expenses.

Q. What is the source of the data, which you will present by way of testimony or exhibits 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 this Commission.

Q. Have you prepared an exhibit in this proceeding?

A. Yes. I have prepared Exhibit No.___ (JDJ-1), Fuel and Purchased Power Cost Recovery and Capacity Cost Recovery that contains four documents as described in my testimony.

CAPACITY COST RECOVERY CLAUSE

Q. What is the net true-up amount for the capacity cost recovery clause for the period January 2002 through December 2002?

A. The net true-up amount is an under-recovery of $314,462.

Q. Please explain Document No. 1.

A. Document No. 1, page 1 of 4 entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of Final True-up Variances for the Period January 2002 through December 2002" shows the calculation of the final net true-up under-recovery of $314,462. The actual capacity cost under-recovery, including interest was $1,842,516 for the period January 2002 through December 2002 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the actual/estimated under-recovery approved in FPSC Order No. PSC-02-1761-FOF-EI issued December 13, 2002 in Docket No. 020001-EI of $1,528,054, results in a final under-recovery for the period of $314,462 as identified in Document No. 1, page 4 of 4. This under-recovery amount will be applied in the calculation of the capacity cost recovery factors for the period January 2004 through December 2004.

Q. What is the estimated effect of this $314,462 under-recovery in the January 2002 through December 2002 period, on residential bills during the January 2004 through December 2004 period?

A. The $314,462 under-recovery will cause a 1,000 kWh residential bill to be approximately $0.02 higher.

Incremental Security Alert Expenses

Q. What were Tampa Electric's actual costs for security alert expenses as a result of the events of September 11, 2001?

A. As shown in Document No. 1, Page 2 of 4, line 4, Tampa Electric incurred security alert expenses of $816,076 for incremental O&M security expenses for measures taken by the company to protect its generating facilities. The incremental security expense shown represents actual expenses of $400,652 and $415,424 incurred in 2001 and 2002, respectively.

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE

Q. What is the net true-up amount for the Fuel and Purchased Power Cost Recovery Clause for the period January 2002 through December 2002?

A. The net fuel true-up is an under-recovery of $28,662,327. The actual fuel cost under-recovery, including interest, was $31,827,918 for the period January 2002 through December 2002. This $31,827,918 amount, less the actual/estimated under-recovery amount of $3,165,591 approved in Order No. PSC-02-1761-FOF-EI issued December 13, 2002 in Docket No. 020001-EI results in a final under-recovery amount for the period of $28,662,327. In accordance with Order no. PSC-03-0400-PCO-EI issued March 24, 2003 in Docket No. 030001-EI, $26.0 million of the total $28,662,327 final under-recovery was applied in the calculation of the fuel recovery factors for the period April 2003 through December 2003. The remaining $2,662,327 under-recovery will be applied in the calculation of the fuel recovery factors for the period January 2004 through December 2004.

Q. What is the estimated effect of the remaining $2,662,327 under-recovery from the January 2002 through December 2002 period on residential bills during the January 2004 through December 2004 period?

A. The $2,662,327 under-recovery will cause a 1,000 kWh residential bill to be approximately $0.15 higher.

Q. Please explain Document No. 2.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel Over/(Under)- Recovery for the Period January 2002 through December 2002". It shows the calculation of the final fuel under-recovery for the period of $28,662,327.

Line 1 shows the total company fuel costs of $523,259,217 for the period January 2002 through December 2002. The jurisdictional amount of total fuel costs is $512,067,602 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 $21,862,398 under-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 $31,827,918 shown on line 8. The $31,827,918 less the actual/estimated under-recovery of $3,165,591 shown on line 9, results in a final under-recovery amount for the period of $28,662,327 as shown on line 10.

Q. Please explain Document No. 3.

A. Document No. 3 entitled "Tampa Electric Company Calculation of True-up Amount Actual vs. Original Estimates for the Period January 2002 through December 2002", shows the calculation of the actual under-recovery as compared to the original estimate for the same period.

Q. What was the variance in jurisdictional fuel revenues for the period January 2002 through December 2002?

A. As shown on line C3 of Document No. 3, the company collected $5,277,724 or 1.1 percent less jurisdictional fuel revenues than originally estimated.

Q. What was the total fuel and net power transaction cost variance for the period January 2002 through December 2002?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost variance is $1,727,938 or 0.3 percent less than originally estimated.

Q. Please explain Document No. 4.

A. Document No. 4 contains Commission Schedules A1 through A9 for the months of January 2002 through December 2002. Also included is a twelve-month summary detailing the transactions for each of Commission Schedules A6, A7, A8, and A9 for the period January 2002 through December 2002.

Deferred Earnings Plan Refund

Q. Has Tampa Electric completed disbursement of the refund associated with the company's 1999 earnings as contemplated in Order Nos. PSC-01-255-FOF-EI and PSC-01-

255-FOF-EI in Docket Nos. 950379-EI and 950379-EI, respectively?

A. Yes. As of June 30, 2002, the total amount subject to refund including interest was $6,385,474. The refund was disbursed during June 2002 through August 2002. Tampa Electric actually refunded a total of $6,131,115 to its customers. Therefore, the difference or true-up associated with the refund is $254,359, which is shown on Document No. 3, line C6E.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2003 as derived in accordance with Order No. PSC-01-2371-FOF-EI, Docket No. 010283-EI?

A. The company's 2003 benchmark is $1,546,058, which is the three-year average of $2,287,740, $1,512,133 and $838,302 actual gains on the non-separated wholesale sales, excluding emergency, for 2000, 2001 and 2002, respectively.

Hedging Transaction and Incremental O&M Costs

Q. Did Tampa Electric prudently incur any transaction and incremental O&M expenses for initiating and/or maintaining its non-speculative financial hedging program in 2002?

A. Yes. Tampa Electric prudently incurred $83,786 for incremental O&M hedging expenses, which are shown on Document No. 3, Line A6C. Exhibit____ (JTW-1) of the direct testimony of witness J. T. Wehle itemizes the incremental O&M expenses by category.

Q. Does this conclude your testimony?

A. Yes.

BY MR. BEASLEY:

Q Ms. Jordan, did you also prepare and submit actual estimated true-up testimony for the period January 2003 through December 2003 that you caused to be filed on August the 12th of this year?

A Yes.

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

A No, I do not.

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

A Yes, they would.

MR. BEASLEY: I'd ask that Ms. Jordan's actual estimated true-up testimony be inserted into the record as though read.

CHAIRMAN JABER: The prefiled testimony of J. Denise Jordan filed August 12th shall be inserted into the record as though read.

BY MR. BEASLEY:

Q Ms. Jordan, did you have prepared under your direction and supervision the exhibit identified JDJ-2 that was also filed on August 12th?

A Yes, I did.

MR. BEASLEY: I'd ask that Exhibit JDJ-2 be marked.

CHAIRMAN JABER: JDJ-2 will be marked as Exhibit 29.

(Exhibit Number 29 marked for identification.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
FILED: 8/12/03

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. DENISE JORDAN

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

A. My name is J. Denise Jordan. 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 Director, Rates and Planning in the Regulatory Affairs Department.

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

A. I received a Bachelor of Mechanical Engineering degree in 1987 from Georgia Institute of Technology in Atlanta, Georgia. Prior to joining Tampa Electric, I accumulated 13 years of electric utility experience working in the areas of rate design and administration, demand-side management implementation, commercial and industrial account management, customer service and marketing. In April 2000, I joined Tampa Electric as Manager, Electric Regulatory Affairs. In February 2001, I was promoted to

Director, Rates and Planning. My present responsibilities include the areas of fuel and purchased power, capacity, environmental and energy conservation cost recovery clauses, rate design, strategic planning and load research and forecasting.

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 2003 through December 2003 fuel and purchased power and capacity true-up amounts to be recovered in the January 2004 through December 2004 projection period. My testimony addresses the recovery of fuel and purchased power costs, incremental hedging operations and maintenance ("O&M") costs, capacity costs and incremental O&M security costs for the year 2003, based on six months of actual data and six months of estimated data. This information will be used to determine fuel and purchased power cost and capacity cost recovery factors for the year 2004.

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

A. Yes. I have prepared Exhibit No. ____ (JDJ-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 of January 2003 through December 2003. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2003 through December 2003. 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 2004 through December 2004 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2003 through December 2003 is an under-recovery of $91,007,445.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2004 through December 2004 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2004 is the sum of the final true-up amount for the period of January 2002 through December 2002 and the actual/estimated true-up amount for the period of January 2003 through December 2003.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2002?

A. The true-up was an under-recovery of $28,662,327. The actual fuel cost under-recovery, including interest, was $31,827,918 for the period January 2002 through December 2002. The $31,827,918 amount, less the actual/estimated under-recovery amount of $3,165,591 approved in Order No. PSC-02-1761-FOF-EI issued December 13, 2002 in Docket No. 020001-EI results in a final under-recovery amount for the 2002 period of $28,662,327. However, in accordance with Order No. PSC-03-0400-PCO-EI issued March 24, 2003 in Docket No. 030001-EI, $26,000,000 of the total $28,662,327 final under-recovery was applied in the calculation of the fuel recovery factors for the period April 2003 through December 2003. The remaining $2,662,327 under-recovery will be applied in the calculation of the fuel recovery factors for the period January 2004 through December 2004.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2003 through December 2003?

A. The actual/estimated fuel and purchased power cost recovery true-up is an under-recovery amount of $88,345,118 for the January through December 2003 period. This net true-up amount includes the company's estimated current period under-recovery of $26,000,000 in projected costs reported in Tampa Electric's request for a mid-course adjustment filed February 24, 2003. In Order No. PSC-03-0400-PCO-EI issued March 24, 2003, the Commission decided not to address, at that time, the recovery of $26,000,000 of 2003 projected costs requested by Tampa Electric in its February 24, 2003 mid-course petition. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit ____ (JDJ-2), Document No. 1 on Schedule E1-B.

Q. Are incremental hedging O&M costs included in the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2003 through December 2003?

A. Yes. The Commission authorized the recovery of prudently-incurred incremental O&M expenses incurred for the purpose of initiating and/or maintaining a new or expanded non-speculative financial and/or physical hedging program designed to mitigate fuel and purchased power price volatility for its retail customers in Order No. PSC-02-1484-FOF-EI, issued October 30, 2002 in Docket No. 011605-EI. Therefore, as shown on Exhibit ____ (JDJ-2), Document No. 1 on Schedule E1-B, line A-5b, Tampa Electric included $190,847 actual and estimated incremental hedging O&M costs in its 2003 actual/estimated true-up calculation.

Q. How are the incremental hedging O&M costs calculated?

A. The total anticipated costs for 2003 are $360,000, and the base level amount is $169,153. Therefore, the incremental hedging O&M cost is calculated by subtracting the base level amount of $169,153 from the $360,000 of total anticipated costs, which results in an incremental expense of $190,847.

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

A. The currently projected incremental hedging O&M cost is $224,153 less than the original projected cost. As Tampa

Electric stated in witness Joann Wehle's testimony filed September 20, 2002 in Docket No. 020001-EI, the company plans to purchase a software system to more efficiently track, monitor and evaluate hedging transactions. Originally, the implementation of that system was expected to be complete in 2003. Currently, Tampa Electric expects that the implementation will begin in 2003 and be completed in 2004. Therefore, some implementation costs will be shifted into 2004 and will be included in the 2004 projected costs.

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 2004 through December 2004 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2003 through December 2003 is an under-recovery of $2,161,509 as shown in Exhibit ____ (JDJ-2), Document No. 2, page 2 of 3.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2004 through December 2004 capacity cost recovery factors?

A. Tampa Electric calculated the net true-up amount to be recovered in 2004 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 2004 capacity cost recovery factors is the sum of the final true-up amount for 2002 and the actual/estimated true-up amount for January 2003 through December 2003.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2002?

A. The final true-up amount is an under-recovery of $314,462 per the company's April 1, 2003 true-up filing and as shown in Exhibit ____ (JDJ-2), Document No. 2, page 1 of 3.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2003 through December 2003?

A. The actual/estimated true-up amount is an under-recovery of $1,847,047 as shown on Exhibit ____ (JDJ-2), Document No. 2, page 1 of 3.

Q. Are incremental security O&M costs included for 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 ____ (JDJ-2), Document No. 2, Page 2 of 3, the company requests recovery of $178,482, after jurisdictional separation, for 2003 actual/estimated incremental security O&M expenses.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Ms. Jordan, did you prepare and submit projection testimony on September 12th, 2003?

A Yes, I did.

Q Do you have any changes or corrections to that?

A No, I do not.

Q 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 Ms. Jordan's projection testimony be filed or inserted into the record as though read.

CHAIRMAN JABER: The prefiled testimony of. J. Denise Jordan filed September 12th shall be inserted into the record as though read.

BY MR. BEASLEY:

Q And did you have prepared under your direction and supervision the exhibit identified JDJ-3 that accompanied that September 12th testimony?

A Yes, I did.

MR. BEASLEY: I'd ask that JDJ-3 be marked for identification.

CHAIRMAN JABER: It will be marked as Exhibit 30.

(Exhibit Number 30 marked for identification.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
FILED: 09/12/03

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. DENISE JORDAN

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

A. My name is J. Denise Jordan. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Rates and Planning in the Regulatory Affairs Department.

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

A. I received a Bachelor of Mechanical Engineering degree in 1987 from Georgia Institute of Technology in Atlanta, Georgia. Prior to joining Tampa Electric, I accumulated 13 years of electric utility experience working in the areas of rate design and administration, demand-side management implementation, commercial and industrial account management, customer service and marketing. In April 2000, I joined Tampa Electric as Manager, Electric Regulatory Affairs. In February 2001, I was promoted to

Director, Rates and Planning. My present responsibilities include the areas of fuel and purchased power, capacity, environmental and energy conservation cost recovery clauses, rate design, strategic planning and load research and forecasting.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. On behalf of Tampa Electric, I have testified before this Commission in Docket Nos. 010001-EI and 020001-EI regarding regulatory treatment and cost recovery of fuel and purchased power expenses. I also testified in Docket No. 010283-EI, which addressed the calculation of gains and the appropriate regulatory treatment for non-separated wholesale energy sales. In addition, I have filed direct testimony and appeared before this Commission on behalf of the company in several other dockets.

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 and the projected wholesale incentive benchmark for January 2004 through December 2004. In addition, I will address the 2004 projected incremental security costs due to increased security as a result of the September 11, 2001 attacks, the appropriate base amount and period for calculating incremental security costs as well as the projected incremental operating and maintenance ("O&M") costs associated with Tampa Electric's hedging activities. I will also discuss the appropriate regulatory treatment of any costs associated with the resale of surplus coal and dead freight coal transportation costs due to the Gannon Unit 1 through 4 shutdown. Finally, I will describe significant events that affect the factors and provide an overview of the composite effect from the various cost recovery factors for 2004.

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

A. Yes. My Exhibit No. ____ (JDJ-3), consisting of three documents, was prepared under my direction and supervision. Document No. 1 of Exhibit No. ____ (JDJ-3) is furnished as support for the projected capacity cost recovery factors. In support of the proposed levelized fuel and purchased power cost recovery factors, Document

No. 2 is comprised of Schedules E-1 through E-10 for January 2004 through December 2004 and Schedule H-1 for January through December, 2001 through 2004. Document No. 3 provides the composite effect of the proposed cost recovery factors on a 1,000 kilowatt-hour ("kWh") residential bill.

Capacity Cost Recovery Clause

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. ___ (JDJ-3), Document No. 1, Projected Capacity Cost Recovery.

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

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

Q. Has Tampa Electric included costs for security alert expenses as a result of the events of September 11, 2001?

A. Yes. The Commission has authorized in previous years' fuel docket hearings, the recovery of incremental security O&M costs arising as a result of the extraordinary circumstances of the attacks of September 11, 2001, through the capacity clause. Therefore, as shown on Exhibit ____ (JDJ-3), Document No. 1, Tampa Electric requests recovery of $114,523, after jurisdictional separation, for estimated expenses in 2004.

Q. Please summarize the proposed capacity cost recovery clause factors by rate schedule for January 2004 through December 2004.

A.

Rate Schedule	**Capacity Cost Recovery Factor (cents per kWh)**
Average Factor	0.216
RS	0.267
GS and TS	0.244
GSD, EV-X	0.210
GSLD and SBF	0.185
IS-1, IS-3, SBI-1, SBI-3	0.016

SL-2, OL-1 and OL-3 0.105

These factors are shown in Exhibit No. ___ (JDJ-3), Document No. 1, page 3 of 3.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.216 cents per kWh compare to the factor for January through December 2003?

A. The proposed capacity cost recovery factor is 0.011 cents per kWh (or $0.11 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.227 cents per kWh for the January 2003 through December 2003 period.

Incremental Security Cost Baseline

Q. How did Tampa Electric establish the baseline for calculating its incremental security O&M costs that resulted from the attacks on September 11, 2001?

A. The O&M expenses Tampa Electric incurred for security measures implemented to protect the company's generating facilities as a result of the September 11, 2001 attacks were and continue to be tracked and recorded separately in accounts created specifically for capturing such expenses. As a result, the expenses have never been commingled with the company's on-going security expenses, thereby eliminating any need for a baseline.

Fuel and Purchased Power Cost Recovery Factors

Q. What is the appropriate value of the base fuel and purchased power cost recovery factor for the year 2004?

A. The appropriate value for the new period is 3.967 cents per kWh before the normal application of factors that adjust for variations in line losses. Schedule E1 of Exhibit No. ___ (JDJ-3), Document No. 2, Fuel Projection, shows the appropriate values for the total fuel and purchased power cost recovery factor as projected for the period January 2004 through December 2004.

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

A. The GPIF and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF penalty of $2,496,021, which is to be 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 2003 through December 2003 period. The net true-up amount for this period is an under-recovery of $91,007,445.

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 2004 through December 2004.

Q. What is the purpose of Schedule E1-E?

A. The purpose of Schedule E1-E is to present the standard, on-peak and off-peak fuel adjustment factors after adjusting for variations in line losses.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by rate schedule for January 2004 through December 2004.

A.

Rate Schedule	**Fuel Charge Factor (cents per kWh)**
Average Factor	3.967
RS, GS and TS	3.984
RST and GST	4.999 (on-peak)

	3.460	(off-peak)
SL-2, OL-1 and OL-3	3.691	
GSD, GSLD, and SBF	3.969	
GSDT, GSLDT, EV-X and SBFT	4.980	(on-peak)
	3.447	(off-peak)
IS-1, IS-3, SBI-1, SBI-3	3.866	
IST-1, IST-3, SBIT-1, SBIT-3	4.851	(on-peak)
	3.357	(off-peak)

Q. How does Tampa Electric's proposed average fuel adjustment factor of 3.967 cents per kWh compare to the average fuel adjustment factor for the April 2003 through December 2003 period?

A. The proposed fuel charge factor is 0.532 cents per kWh (or $5.32 per 1,000 kWh) higher than the average fuel charge factor of 3.435 cents per kWh for the April 2003 through December 2003 period.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2004?

A. The company's projected 2004 benchmark is $1,261,681, which is the three-year average of $1,512,133, $838,302 and $1,434,606 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2001, 2002 and 2003 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2004 from non-separated wholesale sales to exceed its 2004 wholesale incentive benchmark?

A. Yes. Tampa Electric anticipates that sales will exceed the projected benchmark by $683,819 of which 80 percent or $547,055 will flow back to ratepayers.

Incremental Hedging O&M Costs

Q. Is Tampa Electric seeking to recover prudently incurred projected incremental O&M costs for initiating and/or maintaining its non-speculative financial hedging program in 2004?

A. Yes. The projected incremental O&M expenses are shown on Exhibit No. ____ (JDJ-3), Document No. 2, Schedule E2, line 8c. Exhibit No. ____ (JTW-3) of the direct testimony of Tampa Electric witness J. T. Wehle itemizes the expected O&M expenses by functional category.

Regulatory Treatment

Q. What is the appropriate treatment for any gains or losses on the resale of surplus coal due to the shutdown of Gannon Units 1 through 4?

A. As described in the testimony of witness Wehle, due to the company's efforts to mitigate the impact of any surplus coal from Gannon Station, Tampa Electric currently expects the impact on ratepayers to be neutral and there remains the potential for ratepayers to experience net gains. The company's projected 2004 fuel and purchased power costs do not include any gains or losses on the resale of surplus coal; however, if there are any gains or losses, the appropriate regulatory treatment would be to pass the gains or losses through the Fuel and Purchased Power Cost Recovery Clause.

Q. What is the appropriate regulatory treatment of any dead freight coal transportation costs related to the shutdown of Gannon Units 1 through 4?

A. As described in the direct testimony of witness Wehle, due to the dynamic nature of calculating potential dead freight costs, Tampa Electric does not have a viable projection of potential dead freight costs at this time.

Therefore, the company's projected 2004 fuel and purchased power costs do not include any dead freight costs. In the event that there are dead freight costs, the appropriate regulatory treatment would be recovery of the actual costs through the Fuel and Purchased Power Cost Recovery Clause.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2004 fuel and purchased power and capacity cost recovery projections that were not reflected in last year's projections?

A. Yes. There are two significant events. These are 1) Tampa Electric's 2003 estimated net true-up under-recovery amount of $91,007,445, and 2) the company's fuel mix transition due to the repowering of the Gannon Station to the Bayside Power Station.

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

A. On August 11, 2003, Tampa Electric notified the Commission that the company had determined that its projected actual/estimated fuel and purchased power cost under-recovery for the 2003 cost recovery period would be greater than the ten percent notification threshold set forth in Order No. 13694. In view of the timing of the determination, Tampa Electric did not request a mid-course correction but, instead, is seeking recovery of the projected 2003 under-recovery as a component of the company's 2004 fuel cost recovery factors. Therefore, the net true-up amount to be recovered in 2004 is $91,007,445, which is the sum of the final true-up amount for the period of January 2002 through December 2002 and the actual/estimated true-up amount for the period of January 2003 through December 2003.

The 2002 final true-up was an under-recovery of $28,662,327. However, in accordance with Order No. PSC-03-0400-PCO-EI issued March 24, 2003 in Docket No. 030001-EI, $26,000,000 of the total $28,662,327 final under-recovery was applied in the calculation of the fuel and purchased power cost recovery factors for the period April 2003 through December 2003, leaving the remaining $2,662,327 under-recovery for inclusion in the calculation of the fuel cost recovery factors for the period January 2004 through December 2004. In addition, the actual/estimated fuel and purchased power cost recovery true-up for the January through December 2003 period is an under-recovery of $88,345,118. This 2003 net true-up amount includes $26,000,000 in projected costs that the company estimated as part of its under-recovery that was reported in Tampa Electric's request for a mid-course adjustment filed February 24, 2003. In Order No. PSC-03-0400-PCO-EI issued March 24, 2003, the Commission decided not to address, at that time, the recovery of $26,000,000 of 2003 projected costs requested by Tampa Electric in its February 24, 2003 mid-course petition.

Q. Please describe the second event.

A. As described in the direct testimony of witness Wehle, Tampa Electric will continue to shift from a predominant reliance on coal-fired generation to a mix of coal and natural gas-fired generation due to the repowering of Gannon Station to Bayside Power Station. Bayside Unit 1, a 709 MW (summer rating) gas-fired unit, began commercial operation in April 2003. Bayside Unit 2, a 908 MW (summer rating) gas-fired unit, is expected to begin commercial operation in January 2004. Therefore, the 2004 projection period includes 12 months of Bayside Station natural gas fuel generation expenses, which increases net system generation fuel costs.

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 $5.33 beginning January 2004. These charges are shown in Exhibit___(JDJ-3), Document No. 3.

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 2004.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Ms. Jordan, did you prepare supplemental direct testimony pertaining to the security issue that was filed on November 3, 2003, in this proceeding?

A Yes, I did.

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

A They would.

MR. BEASLEY: I'd ask that Ms. Jordan's supplemental direct testimony be inserted into the record as though read.

CHAIRMAN JABER: Supplemental direct testimony filed November 3rd shall be inserted into the record as though read.

MR. BEASLEY: Thank you.

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
FILED: 11/03/03

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED SUPPLEMENTAL DIRECT TESTIMONY

OF

J. DENISE JORDAN

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

A. My name is J. Denise Jordan. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Rates and Planning in the Regulatory Affairs Department.

Q. Are you the same Denise Jordan who submitted Direct Testimony on September 12, 2003 and Rebuttal Testimony on October 16, 2003 in this proceeding?

A. Yes, I am.

Q. What is the purpose of your supplemental direct testimony?

A. The purpose of my supplemental direct testimony is to address the appropriate methodology for determining the incremental costs of security measures implemented as a result of the September 11, 2001 terrorist attacks.

Q. Does Tampa Electric seek recovery of incremental operating and maintenance ("O&M") expenses for security measures as a result of the events of September 11, 2001?

A. Yes. As I stated in my direct testimony filed September 12, 2003, Tampa Electric is requesting recovery of $114,523, after jurisdictional separation, through the Capacity Cost Recovery Clause for estimated incremental security O&M expenses in 2004.

Q. Please describe how Tampa Electric established a base year amount or baseline for calculating its incremental security O&M costs?

A. The unanticipated security expenses incurred for measures implemented to protect the company's generating facilities as a result of September 11, 2001 were not included in Tampa Electric's last base rate proceeding; therefore, all such security expenses are incremental. Accordingly, the company's base year or baseline amount is zero. Additionally, the incremental security expenses were and continue to be tracked and recorded separately in accounts created specifically for tracking such expenses. As a result, the expenses have never been commingled with the company's on-going security expenses, thereby eliminating any need for a baseline comparison or reconciliation of expenses to the preceding year.

Q. Has the Florida Public Service Commission's Division of Auditing and Safety reviewed Tampa Electric's incremental security expenses? If so, what were the findings?

A. Yes. Exhibit______ (JYS-1) from the direct testimony of Ms. Jocelyn Stephens, testifying on behalf of the Florida Public Service Commission Staff, includes the Base Year Cost Final Audit Report, Audit Control No. 02-340-2-1, for Tampa Electric, which states the following in Audit Disclosure No. 1:

> "…the Company was able to provide security by function for incremental costs incurred as a result of the 9/11 event."

In addition, page 3, lines 7 through 11 of Ms. Stephens' testimony states:

> "We prepared schedules for the years 2001, 2002 and projected 2003, by account, by month, for security costs recorded in the general ledger. In order to determine the amount of normal and

recurring security costs, we removed those costs identified by the company as incremental. The resulting amount equals actual security costs on a consistent basis."

The audit results concur with the company's position that its security expenses incurred as a result of the events of September 11, 2001 are indeed incremental.

Q. Do you agree that expenses from a base year used for comparison purposes need to be grossed up by the growth rate in energy sold since the base year to the recovery year?

A. No, I do not. As I stated earlier, a baseline comparison of the base year amounts to the recovery year is not needed because the company's expenses for security measures due to the events of September 11, 2001 are incremental. In any event, there is no correlation between the growth rate in energy sales and the level of expenses included in base rates and it would be inappropriate to simply assume one.

Q. Does this conclude your testimony?

A. Yes it does.

BY MR. BEASLEY:

Q Ms. Jordan, would you please summarize your testimony for the Commission.

A Good morning, Commissioners. My direct testimony presents for Commission review and approval the proposed annual capacity cost recovery factors, the proposed fuel and purchased power cost recovery factors, and the projected wholesale incentive benchmark for January 2004 through December 2004.

My testimony also presents projected incremental security costs as a result of the September 11th, 2001, attacks, the appropriate base amount and -- the appropriate base amount and period for calculating incremental security costs, as well as the projected incremental O&M costs associated with the company's hedging activities.

Tampa Electric's last base rate proceeding did not include any security costs for measures implemented to protect the company's generating facilities as a result of the September 11th, 2001, attacks; therefore, all these security costs are incremental.

In addition, the incremental security expenses have been and will continue to be tracked and recorded separately. These expenses have never been commingled with Tampa Electric's ongoing security expenses, which eliminates the needs for a baseline comparison for reconciling the expenses to expenses incurred in the previous year.

Tampa Electric's incremental security expenses have been reviewed by the Commission's division of auditing and safety staff, and the audit results concur with the company's position that its security expenses incurred are incremental.

My testimony also addresses the proposal to gross up expenses from a base year that are used for comparison purposes according to the growth rate in energy sales. It is inappropriate to assume a correlation between the growth rate in energy sales and the level of expenses included in base rates. In any regard, such a measure is not warranted for Tampa Electric because the company's base year amount is zero. That concludes my summary.

MR. BEASLEY: We tender Ms. Jordan for questions.

CHAIRMAN JABER: Thank you, Mr. Beasley.

MR. BUTLER: Ms. Jaber or Commissioner Jaber -- sorry.

CHAIRMAN JABER: Yes.

MR. BUTLER: I have some very brief examination concerning her supplemental testimony.

CHAIRMAN JABER: Security issues, security costs?

MR. BUTLER: Yes.

CHAIRMAN JABER: Go ahead, Mr. Butler.

CROSS EXAMINATION

BY MR. BUTLER:

Q Ms. Jordan, are you familiar with Mr. Brinkley's

testimony concerning grossing up the baseline for determining incremental power plant security costs by the growth in kilowatt hour sales?
A Yes, I am.
Q Okay. And is it your understanding that Mr. Brinkley's proposal is based on the idea that a utility's revenue requirements are generally expected to grow in proportion to the growth in its revenues?
A Yes.
Q Okay. Do you believe that this expectation is realistic when it's applied to power plant security costs?
A No, I do not.
Q And would you explain why, please?
A Basically because you, you cannot assume, for example, that if you have growth that is occurring for, let's say T&D security, if that is growing and you're going to adjust the overall security costs, that's not in relationship to what's happening at a generation facility. You would not assume that you were going to hire an additional security guard because you sold more kilowatt hours that particular year. It is not a direct relationship.
MR. BUTLER: Thank you. That's all that I have.
CHAIRMAN JABER: Mr. Vandiver.
CROSS EXAMINATION
BY MR. VANDIVER:

Q Good morning, Ms. Jordan.
A Good morning.
Q I'm in your August 12th testimony at Page 4. Lines 18 through 20, you reference the midcourse correction.
A Correct.
Q That was a 26 of the -- what was that midcourse correction due to?
A That midcourse correction was due to increased natural gas prices as well as increased purchased power expenses.
Q Was that partially due to the shutdown of Gannon Station?
A In what regard, sir?
Q You closed down Gannon Station, several units, four units early. Was part of that due to the shutdown of Gannon Station --
A I don't think the actual --
Q -- the midcourse correction?
A I don't think the midcourse correction was due to the shutdown.
Q So none of that played into the shutdown of Gannon?
A Was it a factor in determining our overall fuel cost recovery?
Q Yes.
A Yes.

Q Can you quantify how much of that was due to the shutdown of Gannon?

A I can refer you to the documents that you talked with Mr. Whale on yesterday with regards to the scenarios that were presented by the company that looked at the various impacts.

Q Okay. But you can't just ballpark it looking at it of the $26 million, but you can say that it played a part in the midcourse correction?

A It played a part in the cost recovery of the dollars, yes.

Q Okay. And you're presently seeking, back on Page 3 of the same testimony, you're presently looking at an underrecovery of $91 million; is that correct?

A I'm sorry, sir. I can't hear you.

Q Back on Page 3 you're presently seeking an underrecovery of $91 million?

A That is correct.

Q Okay. And if we could go to -- let's go to Page 13, Schedule A3.

A Same document?

Q Yes. Same document. Page 13 at the bottom, Schedule A3. I'm looking at your generation mix in January. It's about halfway down the page. And at that time your generation mix was 96.31 percent coal. I'm looking at the January '03 figure.

A I'm there.

Q Okay. Is that correct?

A Yes.

Q And then if we could turn to the next page on 14, Page 14, I'm still on Schedule A3, and I'd like to look at December '03 and look at that same generation mix figure. Could you read the coal and natural gas percentages, please, into the record.

A 55.05, 44.06.

Q And is that switch in your generation mix principally due to the closure of Gannon Station and the opening of Bayside?

A It's due more primarily to the opening of Bayside, yes.

Q Okay. I'd now like to go to the bottom of that page and the entries there, Generated Fuel Costs Per Kilowatt Hour, Cents Per Kilowatt Hour, Lines 57 and 58. Do you see those two entries, Coal and Natural Gas?

A Yes, sir.

Q Earlier with Mr. Smith -- I believe you were in the room when I was discussing the fuel costs with Mr. Smith.

A Yes.

Q Could you read the coal costs into the record and the natural gas costs into the record?

A 2.19, 5.16.

Q Okay. And just again on a very high level, the, the generation that was at Gannon is the former, is the coal cost; is that correct? The Gannon was a coal-fired, were coal-fired units, were they not?

A Yes.

Q And Bayside, the new unit is natural gas-powered, is it not?

A That's correct.

Q And I believe when -- and so if we were looking at a very simplistic example, and I know that Mr. Smith talked about a myriad of factors that go into power and so forth, but if we were looking on a very simplistic level of natural gas supplanting coal, we could subtract those two figures and come up with a simplistic example, couldn't we?

A A simplistic example of what?

Q Of natural gas supplanting coal.

A Okay.

Q For the Gannon Units.

A Just --

Q Bayside replacing Gannon.

A Just a delta, is that what you're asking?

Q Yes. Yes.

A Sure.

Q Okay. And if we were to multiply out the lost generation, say, for 2002, we could come up with a number, couldn't we?

A I'm not sure what that number would represent, but, yes, mathematically we could come up with a number.

MR. VANDIVER: Okay. That's all the questions I have at this time. Thank you.

CHAIRMAN JABER: Thank you, Mr. Vandiver.

Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Ms. Jordan, in, in your direct testimony you said that --

MR. BEASLEY: Which testimony?

MR. McWHIRTER: You stated -- oh, the presentation she made just a minute ago, the verbal presentation.

MR. BEASLEY: Summary. Okay.

MR. McWHIRTER: And I think it also deals with Page 1 -- no, it doesn't.

BY MR. McWHIRTER:

Q But I'm talking about incremental security costs, and you said it's improper to follow Mr. Brinkley's approach because those costs don't vary with respect to the kilowatt hours sold. Is that essentially what you were saying?

A Yes.

Q And for that reason what is the justification for collecting any security costs on a kilowatt-hour basis through a cost recovery clause?

A We're actually not recovering the costs through on a kilowatt-hour basis, sir.

If you remember correctly, we're flowing it through the capacity clause, which is actually allocated on a demand basis, which is more in line with the way the traditional base rate recovery would occur.

Q I see. And Mr. Whale, when he testified yesterday, he was unfamiliar with the distinction between base rates and cost recovery clauses. Do you recall that? He didn't know who got the hit when fuel costs went up.

You know the difference between base rates and cost recovery, don't you?

A I do know the difference. And I wouldn't use the term "hit." I would use the term "recovery of the dollars." But, yes.

Q I see. But on Page 9 at Line 15 of your September 12th testimony, the average residential customer if he consumes only 1000 kilowatt hours a month will pay how much additional each month as a result of your increased fuel costs?

A $5.32.

Q Now on Page 12, you say that there's no charge in the current factor for dead-freight charges paid in your testimony and you're not requesting it now, and that pretty well confirms what Ms. Wehle said. So you're not asking for any in 2003 and you're not asking for any dead-freight charges in 2004 as part of the fuel cost recovery?

A That's correct.

Q And she said that that will come up in the deferred section. Do you agree with that?

A That what will come up in the deferred section?

Q The, the dead-freight charges.

A No. There is no dead-freight associated with the existing contract.

Q Okay. And how about the new contract? Will that be written into the new contract to compensate for the loss of freight in the last deal?

A There is no need to write anything in the new contract because there is no dead-freight associated with the existing contract.

Q And that won't be given any, consideration, the reduction in, in the tonnage transport won't be given any consideration in the new contract?

A That is correct.

Q When you carry fewer tons, do you charge more than when you carry a lot of tons on a per ton basis?

A Mr. McWhirter, now you're getting really out of my area of expertise. Ms. Wehle was up earlier, and that was probably more appropriate for her.

Q On Page 12, Line 14 of your September 12th testimony you indicate that there's a $91 million true-up. Does this include 2003 hedging security and transportation adjustments as well as fuel costs?

A Yes. In the total recovery dollars this, all of those items are included.

Q Do you, do you give any line item identification so that a poorly educated person can come in and look at the lines and see how much you paid for hedging and how much you paid for security and so forth?

A Yes, sir, we do. On Exhibit -- on my Exhibit JDJ-3, Document Number 1, Page 2 of 2 that was filed 9/12, Line Item Number 3 actually shows security costs as a separate --

Q Would you slow down and tell me where it is again?

A Bate stamped Page 18 of my testimony filed 9/12, Line Number 3 gives the indication of security costs, for example.

CHAIRMAN JABER: Ms. Jordan, that's JDJ-3, Document Number 1 --

THE WITNESS: Yes.

CHAIRMAN JABER: Page 2 of 3?

THE WITNESS: Yes.

BY MR. McWHIRTER:

Q Okay. And then where would we find the transportation adjustments and the security costs, I mean, the hedging costs?

A Okay. Page -- Bate stamp Page 27, Schedule E2, Line Item 8C, as in Charlie.

CHAIRMAN JABER: Page 27.
THE WITNESS: Yes.
CHAIRMAN JABER: What's the rest?
THE WITNESS: Schedule E2, and it's on Line Number 8C, as in Charlie.
CHAIRMAN JABER: Thank you.
THE WITNESS: Adjustment to fuel cost incremental O&M, hedging O&M.
BY MR. McWHIRTER:
Q And so $280,000 is what you spent for hedging for the -- you propose to spend for hedging?
A For 2004.
Q Is that for premiums or is that -- what is that for?
A Once again, that's something that Ms. Wehle would have been better in a position to answer that question.
Q Go to your Schedule E1.
A Excuse me, Mr. McWhirter. Are we on the same document or --
Q We're still in September of this year for the 2004 forecast. And your generation fuel cost this year is going to be $625 million. What was it this time last year that you projected?
A I don't have that document with me.
Q Would it be $91 million less than the 625?
A No. Because that $91 million also includes the

true-up, the final true-up from 2002. So it would probably be -- well, I can't even say that because you're only including the generation piece and not the purchased power. You're not down to the net fuel and transaction cost line, so I can't tell you what that number would have been without looking back at an old schedule.

Q Go down to Line 28, that's the true-up, the $91 million extra you're asking for this year.

A Well, it's not extra, sir. It's to recover the dollars that have already been spent.

Q And that's money for fuel?

A Yes.

Q And --

A Purchased power, yes.

Q And it appears that you're charging that to -- that's your actual cost compared to your estimated cost; is that right?

A Excuse me, sir?

Q Well, you're off by $91 million. And I guess you're off because you forecasted a number that was $91 million lower than you finally came up with; is that a fair statement?

A Well, yes. There are several components, as you know, to the true-up, so there's the final true-up piece, then there's an actual estimated piece, which has not been obviously finalized yet. It won't be finalized until next year. So it's a combination. But it is all relative to various forecasts.

Q Well, look up here at Line 24. And it shows the price that you're going to charge to your wholesale customers, your average price is $34.73 a megawatt hour. It's in pennies per kilowatt hour.

A That's the system megawatt hour you're referring to. I think the wholesale number is $34.92.

Q Okay. Does that have any true-up in it?

A I think we've had this discussion before.

Q Yes. I don't remember how it came out.

A This schedule does not reflect the true-up piece that is allocated to the wholesale piece, so you do not see this here. But as I've testified to before and provided exhibits to before, we do do a separate true-up for the wholesale PR customers as we do with the retail customers. They don't have the extended lag that the retail customers have because when we reach December, we actually have an actual number for them, we divide it by 12, and we put it on their bill the next year.

Q I'm beginning to remember now.

A Okay.

Q So actually the $91 million is only part of the true-up you're asking for?

A That is only representative of the retail piece.

Q Is there anywhere in here that we can see the wholesale piece?

A No, because this is for the retail reporting.

Q I see.

A Excuse me.

Q That's all right. I'm going to try not to pick on you too hard today, Ms. Jordan.

A Thank you.

Q I know what you're going through?

CHAIRMAN JABER: Ms. Jordan, do you need a break?

THE WITNESS: Excuse me?

CHAIRMAN JABER: Do you need a break?

THE WITNESS: No. I'm okay.

BY MR. McWHIRTER:

Q Mr. Vandiver asked you about the actual for 2003, but on Bate stamp Page 29 of your 2004 testimony you give us an indication of the generation mix for the next year after Bayside 2 comes on. And what is that? Coal is on Line 30 and natural gas is on Line 31.

A Could you repeat the page just to make sure I'm in the right place?

Q Page 29, Schedule E3, Page 2 of 3.

A Okay. Now repeat the question, please.

Q Yes. What is the percentage of your total fuel that's going to be coal and the percentage that's going to be natural gas?

A 57.7 and 41.22.

Q And that's compared to 96 percent coal at the beginning of 2003?

A At the beginning of two thousand --

Q Of 2003 now, not 2004.

A Oh, yes, sir.

Q All right. And I noticed that down there where it talks about the price for natural gas for 2004, you project that that price is actually going down considerably from what it was in 2003. It went up -- your average for 2003 from that exhibit he was asking you about showed it was $5.70 -- or $57 a megawatt hour, and now it's going down to $46 a megawatt hour; is that right? That's what you forecast?

A I didn't personally make the forecast, but I think that is representative of what, what we have reported, yes.

Q In light of that, have you considered perhaps spreading the $91 million over a two-year period rather than a one-year period like you -- in the past you've done that kind of thing to help consumers.

A We have not considered that this time around, and it's primarily based on the experiences that we have had in the past of trying to spread the cost of recovery over an extended period of time and finding out that, since no one has a crystal ball, a lot of times you basically end up digging a deeper hole. And the further you get away from what gas prices are actually doing, it sends a mixed signal to the customers and they don't understand why the costs are still high when gas prices are coming down. So a lot of times it's better to do it more real-time to be more reflective of exactly what's going on.

Q Based on your actual experience, do you think it might even be better to go back to semiannual changes in the fuel factor as opposed to annual?

A I'm not sure that that's going to really address the issue. Because if you really think about it, Mr. McWhirter, it comes down to the timing. Even with the six-month, the semiannual, you're going to have to back up and do your forecast. So you're not going to be guaranteed of a better forecast. So, therefore, you're always going to have a lag. And, in turn, if there's volatility, you're going to see it regardless. Because it's all in the timing of when you do your forecast. You're doing your forecast now, for example, in July and the factors don't go in place until January. A lot of things can happen in that six-month window. So that's no different whether you split the year up in two; you're still going to have that same problem.

Q The interest cost has been a concern to the Commission in its orders over the period of time. What is your commercial paper rate now?

A I don't know right off the top of my head. It's whatever the published rate is.

Q And the rate you use, is it a rate that's peculiar to Tampa Electric Company or is it something that appears in the Wall Street Journal?

A It's the published rate that appears, yeah.

Q Where is it published?

A I assume it is in the Wall Street Journal. I'm sure you're more familiar with it than I am, but.

Q We'll have to ask Mr. Lehfeldt, won't we?

Okay. Go over to Bate stamp Page 47.

Do you want to take a little break?

A I'm good.

Q Okay. Go to the bottom of it where it says, "January through December." And you project that this year you're going to sell -- buy 276,000 megawatts from Hardee Power Partners.

A Megawatt hours. Yes.

Q Uh-huh. Megawatt hours?

A Yes.

Q Are they still going to call it Hardee Power Partners?

A I don't know.

Q Now I did some rough and dirty calculations based upon what Mr. Smith said, and we agreed that the current capacity charge for the Hardee Power contract is about $19.6 million a year or $1.6 million a month. When you divide that by 276,000 megawatt hours, that comes to $71.02 a megawatt hour in capacity payments you're going to be paying to Hardee; is that right?

A I don't know. I've not done that math. I mean, it's your math. If you think it's correct, then I guess it's correct.

Q Yes, ma'am. Well, would you divide $19.6 million by 276,512? You've got the old Hewlett Packard out.

A And what's your question?

Q And what does that come up to?

A Is it $19.6 million?

Q Yes.

MR. BEASLEY: Could I ask where that's reflected in any of the -- where's the reference?

CHAIRMAN JABER: Mr. McWhirter, what -- tell me again the schedule you're looking at and the two numbers you're asking her to divide.

MR. McWHIRTER: The -- I'm recalling Mr. Smith's testimony. He said -- oh, the schedule you're looking at is Schedule 7, it's Bate stamp Page 47. It's -- down at the bottom you see January through December.

CHAIRMAN JABER: Uh-huh.

MR. McWHIRTER: And you see that they're going to buy 276,000 megawatt hours from Hardee and they're going to pay $5 -- or $58.13 a megawatt hour for it.

CHAIRMAN JABER: I don't see the $5.58. I must not be looking at the right place. Bate stamp 47, January 4 through December 4th.

MR. McWHIRTER: And see "HPP"?

CHAIRMAN JABER: Yes.

MR. McWHIRTER: Go out to the end and you'll see 5.813.

CHAIRMAN JABER: Okay.

MR. McWHIRTER: When you -- that's pennies per kilowatt hour. And if you convert that to megawatt hours, it's $58.13 a megawatt hour.

CHAIRMAN JABER: Okay. And you're asking her?

MR. McWHIRTER: And that is what the energy charge is. But what I was asking her to calculate was using what Mr. Smith told us the annual capacity payment was of $19.6 million, I asked her to divide that by the megawatt hours shown here.

CHAIRMAN JABER: And that $19.6 million, remind me, Mr. McWhirter, came from the FERC tariff, didn't it?

MR. McWHIRTER: Yes, ma'am.

CHAIRMAN JABER: Okay. Mr. Beasley, I think with that clarification you don't have an objection anymore; right?

MR. BEASLEY: That's right.

CHAIRMAN JABER: Go ahead, Mr. McWhirter.

MR. McWHIRTER: I confuse myself sometimes, Commissioner Jaber, and that's certainly understandable.

BY MR. McWHIRTER:

Q What did that come up with?

A $70.88.

Q Now would you add that to the $58.13?

A $129.01.

Q That's $129 a megawatt hour you're going to pay Hardee Power Partners?

A I think you should be careful about how you actually do that calculation because, as Mr. Smith indicated, there are two separate products there. One is basically from a CC, which is more utilization and long-term use.

Q Yeah.

A The other one is from the CT 2B, which is more peaking related. So you're going to pay obviously a higher cost for the peaking product than you are for that intermediate product. But, yes, you are right, it's $129. I just think it's misrepresentative because you don't buy it on an average basis. You buy it by the product.

Q Yeah. And, but $58 is your average including both the, the CT and the combined cycle; is that not right?

A Repeat it. I'm sorry.

Q I say the $58 is a melding of the two; it's an average of what you actually buy.

A That's correct.

Q Uh-huh. Of course, it'll vary depending on what you do.

Now Mr. Smith said he was unaware of any obligation that Tampa Electric has to buy kilowatt hours, to buy energy from Hardee Power if they can get it somewhere else. Is that true?

A I would yield to his opinion on that.

Q Okay. Do you know of anything contrary to that?

A I do not know of anything contrary to that. As he indicated, it's a call option. So, therefore, the capacity costs are sunk costs, so to speak. So now you're just looking at the increment of the energy.

Q The capacity cost you're going to pay anyway.

A You're going to pay it regardless.

Q The question is the energy charge. And I notice that your market base energy is $49 as opposed to $58. Does that market base purchase, do those have capacity charges with them?

A It can totally depend on what the product is that you purchase. It could be an energy strip or, yes, it could be a call option, as the Hardee purchase is.

Q Well, when you did your calculations of the capacity charge forecast for next year, did you include a capacity component for this market-based power in 2004?

A Mr. McWhirter, you're making it sound as if that's one single purchase. Those are a myriad of purchases. And Mr. Smith's area would have come up with the forecast and they would have made a determination on what types of product to purchase over the long haul. So there are costs that are associated in the capacity clause, but I can't do one for one because that is, as you indicated with the Hardee, that's two products that's averaged there together. The same with the market base.

Q I'm not asking you that. I'm asking you if there are any capacity charges in the capacity calculations you've done in your exhibit. What page is that capacity exhibit?

A The unit power capacity charges are on Bate stamp Page 18, JDJ-3, Document Number 1, Page 2 of 3, and it's Line Item Number 1.

Q So if there are any capacity charges -- does that $20,000,920, does that include the capacity payments to Hardee?

A Yes.

Q And of the $19.6 million that you're paying Hardee, those capacity payments are broken into three bases. Some is in base rates that were awarded in the 1993 case; I think that's $13 million. Do you have any recollection of that?

A No, sir.

Q Do you know what the capacity payment included in your capacity calculation there on Bate stamp Page 18 is to Hardee Power? Let me restate that question. It's confusing.

Of the $20 million, do you know how much of that goes to Hardee Power?

A I think you asked Mr. Smith that earlier.
Q No. I asked him what he was paid, and he said that you paid $19.6 million. But I want to know if that $19.6 million is in the $20 million, $20.9 million on Page 18.
A And I stated to you earlier that, yes, it was.
Q The whole 19?
A For the capacity payments.
Q All right. Now do you have any familiarity with the 1993 rate case?
A No, sir.
MR. McWHIRTER: I can't ask any more questions of Ms. Jordan under the circumstances. I tender the witness.
CHAIRMAN JABER: Okay.
MR. KEATING: Staff has no questions.
CHAIRMAN JABER: Commissioners? And redirect.
MR. BEASLEY: I have no redirect. I'd like to move Exhibits 28, 29 and 30.
CHAIRMAN JABER: Without objection, Exhibits 28, 29 and 30 are admitted into the record.
(Exhibits 28, 29 and 30 admitted into the record.)
CHAIRMAN JABER: Ms. Jordan, thank you for your testimony.
Mr. McWhirter, are you ready to put Ms. Brown on the stand?
MR. McWHIRTER: Ms. Kaufman is ready.

CHAIRMAN JABER: Okay.

MS. KAUFMAN: Yes, Chairman. We'll call Ms. Brown to the stand on behalf of FIPUG.

CHAIRMAN JABER: Ms. Kaufman, was she in the room yesterday when I swore in witnesses?

MS. KAUFMAN: Yes, ma'am.

SHEREE L. BROWN

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

DIRECT EXAMINATION

BY MS. KAUFMAN:

Q Ms. Brown, you've been sworn; correct?

A Yes, I have.

Q Okay. Would you state your name and business address for the record, please.

A My name is Sheree L. Brown. My business address is 37 North Orange Avenue, Suite 710, Orlando, Florida 32801.

Q Ms. Brown, on whose behalf are you appearing in this proceeding?

A I'm appearing on behalf of the Florida Industrial Power Users Group and the Florida Retail Federation.

Q Ms. Brown, on November 5th did you cause to be filed in this case 26 pages of revised testimony?

A Yes, I did.

Q And can you briefly explain why you needed to file revised testimony?

A Yes. In my original testimony I had addressed the issue of maintenance costs that were addressed in Mr. Whale's testimony. Due to subsequent information that he discussed in his deposition, I felt that I should modify my testimony to address the actual cost as he explained in his deposition.

Q Now do you have any changes or corrections to the revised testimony?

A No, I do not.

Q And if I asked you the same questions in that revised testimony, would your answers today be the same?

A Yes, they would.

Q Now Ms. Brown, your revised testimony has some information in it that Tampa Electric claims is confidential; is that correct?

A That's correct.

MS. KAUFMAN: And, Commissioners, what I've distributed in the red folders are simply those pages that contain information that Tampa Electric claims is confidential.

CHAIRMAN JABER: Thank you, Ms. Kaufman.

MS. KAUFMAN: And Ms. Brown, I think, will be referring to them, and she will do her best to just direct you to the page and the line number.

With that -- and also I have given a copy to the court reporter, so I would ask that Ms. Brown's revised

November 5th testimony including confidential pages be inserted in the record as though read.

CHAIRMAN JABER: The revised direct testimony of Sheree L. Brown shall be inserted into the record as though read.

BY MS. KAUFMAN:

Q Ms. Brown, do you have eight exhibits attached to your testimony SLB-1 through 8?

A Yes, I do.

Q And were they prepared under your direction or supervision?

A Yes.

Q Do you have any changes or corrections to those exhibits?

A No.

MS. KAUFMAN: Madam Chair, if we could have a composite number for those.

CHAIRMAN JABER: SLB-1 through SLB-8 shall be identified as composite Exhibit 31.

(Exhibit Number 31 marked for identification.)

Q: PLEASE STATE YOUR NAME AND OCCUPATION.

A: My name is Sheree L. Brown and I am a Managing Principal of Alliant Energy Integrated Services, located at 710 N. Orange Ave., Suite 710, Orlando, Florida 32801.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A: I graduated Magna Cum Laude from the University of West Florida with a B. A. in Accounting and later received a Masters in Business Administration degree from the University of Central Florida. I am a Certified Public Accountant in the State of Florida and am a member of the American Institute of Certified Public Accountants and the Florida Institute of Certified Public Accountants. Since 1981, I have provided utility consulting services in matters pertaining to electric, water, wastewater, natural gas, steam heat and chilled water utilities. My work has focused in the areas of regulatory affairs, revenue requirements and cost of service, rates and rate design, deregulation and stranded costs, valuation and acquisition, feasibility studies and contract negotiations. A more detailed description of my experience is included in my resume that is attached hereto as Exhibit No.____ (SLB-1).

Q: ON WHOSE BEHALF ARE YOU SPONSORING THIS TESTIMONY?

A: I am sponsoring this testimony on behalf of the Florida Industrial Power Users Group ("FIPUG") and the Florida Retail Federation ("FRF").

Q: WHAT ARE THE INTERESTS OF FIPUG AND FRF IN THIS PROCEEDING?

A: FIPUG and FRF are made up of numerous large utility consumers that take power from Tampa Electric Company ("Tampa Electric"). Unexpected electric rate increases have a significant impact on the operating costs of these companies. The extraordinary increase in fuel costs Tampa Electric has requested has triggered FIPUG's and FRF's concern. Typical residential and small business consumers will not be aware of changes in their fuel costs until such changes have already occurred. FIPUG and FRF felt obliged to express their concern to the Commission in this proceeding.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to address Tampa Electric's extraordinary increase in fuel costs. I recommend that the Florida Public Service Commission ("Commission" or "FPSC") take steps to protect Tampa Electric's ratepayers from subsidizing TECO Energy's financially stressed affiliates. This will protect the credit worthiness of Tampa Electric by limiting the free flow of cash from the healthy regulated utility to its affiliates.

Q: PLEASE SUMMARIZE YOUR TESTIMONY.

A: My testimony reviews the distressed financial condition of TECO Energy and its unregulated companies and the effect the financial problems have on Tampa Electric and its ratepayers. I explain how:

(i) contractual relationships between Tampa Electric and TECO Energy's other subsidiaries have resulted in subsidies of those subsidiaries from Tampa Electric ratepayers;

(ii) dissimilar ratemaking concepts between base rates and cost recovery clauses have afforded an opportunity for the holding company to generate additional cash flow from Tampa Electric at ratepayer expense; and

(iii) the timing of the Tampa Electric's decision to accelerate the closure of the Gannon Power station was concurrent with TECO Energy's desperate need for cash.

I then recommend that the Commission reduce Tampa Electric's $100 million requested rate increase to cover anticipated fuel expenses by [redacted] million of Gannon O&M savings, recognizing that the ratepayers would continue to pay for the discontinued operations through base rates at the same time they would be forced to bear the extraordinary fuel cost increases.

I further recommend that the Commission review Tampa Electric's remaining O&M expenditures for 2003 and 2004 and determine the extent of the expenditures that is attributable to dismantlement activities that ratepayers have already paid for through dismantlement accruals. If a portion of the 2003 and 2004 O&M activities are related to dismantlement, I recommend that the Commission provide an additional offset to the increased fuel expenses for the amount of such dismantlement activities.

With respect to Tampa Electric's dealings with its TECO Energy affiliates, I recommend that the Commission review the HPP contract costs in light of the gain on the sale of HPS to assure that costs are reasonable and reflect HPP's actual investment in the facility and to assure that the change of ownership will not affect ratepayer costs.

Q: PLEASE DESCRIBE THE FINANCIAL STRUGGLES TECO ENERGY FACED

DURING 2002 AND 2003.

A: In 2002, TECO Energy suffered downgrades in its ratings. The downgrades reflected rating agency concerns over TPS investments and the negative impact on TECO Energy's earnings and cash flow as a result of weakness in the wholesale power market. TPS has made substantial investments in generating facilities and rating agencies are concerned with TPS' ability to sell the output. TECO Energy has provided corporate guarantees on TPS projects, including a $500 million equity bridge, additional equity guarantees, and a guarantee of contractors' obligations.

As a result of the downgradings by Fitch, Standard & Poors, and Moodys, TECO Energy developed a business plan to decrease capital expenses by deferring generating projects, selling assets, arranging additional financing, and selling additional common equity. Despite TECO Energy's efforts to increase capital through these measures, the TECO Energy's financial predicament has continued. Ratings were downgraded again, with negative rating outlooks. The reasons for the downgrades included higher-than-expected debt leverage on a cash flow basis, the negative impact on earnings and cash flow measures from increased interest expense, weaker projected earnings, and higher-than-anticipated capital expenditures, in addition to continued concerns over the ability of TPS to recover the significant investments it has made in unregulated generating facilities. TECO Energy also announced a 46% dividend cut.

In April, 2003, Moody's cut TECO Energy's long-term debt rating to junk status, forcing the Company to take additional actions. On July 10, 2003, the TECO Energy was placed on CreditWatch by Standard & Poor's Rating Services due to uncertainties regarding TECO Energy's ability to raise cash by the sale of its synfuel production facilities.

Q: HOW DO THE FINANCIAL DIFFICULTIES FACED BY TECO ENERGY AFFECT TAMPA ELECTRIC?

A: Although Tampa Electric's earnings remain strong, the rating agencies have downgraded Tampa Electric, citing the increase in leverage and business risk at the parent. As noted in a September 15, 2003 report by William Ferara, an analyst from Standard & Poor's:

> TECO's corporate credit rating is based on the financial and business risk profile analysis of the consolidated enterprise and recognizes a free flow of funds throughout the organization and the absence of sufficient regulatory insulation. Thus, the ratings on Tampa Electric are expected to mirror those of TECO, given the absence of proscriptive authority by the regulators in Florida. Any *regulatory insulation or structural separation* imposed to legally ring-fence Tampa Electric would be favorable for the utility's ratings. However, this action would drastically hinder TECO's ability to access the utility's strong cash flows and use its overall financial health to its benefit, which would result in significantly lower ratings at the parent. (emphasis added)

Exhibit No. ____(SLB-2) provides a copy of the September 15, 2003 report from Mr. Ferara, along with a report from the two Moody's analysts and an article from the Saint Petersburg Times. These articles and reports succinctly explain TECO Energy's financial situation. As shown above, the Standard & Poor's article explains how the free flow of funds throughout the organization and the absence of sufficient regulatory insulation has driven down Tampa Electric's credit ratings. This will adversely affect consumers and demonstrates the need for protection of the ratepayers' interests to limit the impact of unfortunate management decisions by TECO Energy and its unregulated subsidiaries.

Q: HOW COULD TECO ENERGY'S FINANCIAL SITUATION AFFECT DECISIONS MADE BY TAMPA ELECTRIC?

A: Under traditional ratemaking practices, a utility has the incentive to decrease non-fuel expenses, and thereby increase earnings, during years between rate cases. Utilities also have the incentive to maximize earnings by the use of contractual relationships between affiliates and the utility. Maximizing the utility's income also provides TECO Energy with the ability to take advantage of tax losses incurred by the non-regulated affiliates. These incentives are increased when a company faces financial struggles such as those faced by TECO Energy.

Q: HOW DOES TRADITIONAL RATEMAKING PROVIDE A UTILITY WITH THE INCENTIVE TO DECREASE NON-FUEL EXPENSES DURING YEARS BETWEEN RATE CASES?

A: Under traditional ratemaking, a utility's base rates are set based on estimated revenue requirements for a particular test year. Once rates are set, the utility's earnings can fluctuate based on actual revenues, expenses, and capital investments. The utility, therefore, has the incentive to maximize revenues and minimize expenses between rate proceedings.

Under current practice, Tampa Electric recovers a large portion of its revenue from the Fuel Cost Recovery Clause, the Capacity Cost Recovery Clause, and the Environmental

Cost Recovery Clause. The use of fuel adjustment clauses has been the practice around the country to protect the utilities and the ratepayers from volatile fuel costs over which the utility does not generally have control. Unlike base rates that give the utility the "opportunity to earn a return," cost recovery clauses essentially guarantee full cost recovery of the targeted costs and investments.

When a portion of a utility's revenue requirement is collected through adjustment clauses, which allow the "pass-through" of costs, a utility has the further incentive of shifting costs from base rate expenses into expenses that are recoverable through the pass-through clauses. While regulated utilities typically have this incentive between rate cases, the incentive is even stronger when a utility is facing financial difficulties. This was the situation faced by Tampa Electric at the time it made its decision to shut down the Gannon Units early. That decision allowed Tampa Electric to decrease its operating and maintenance expenses and increase earnings to the holding company, which can be used to support the cash flow needs of the affiliated companies, while increasing fuel costs, which are a pass-through to ratepayers.

Q: DID TAMPA ELECTRIC RECOGNIZE THIS TILT IN BENEFITS AND COSTS BETWEEN THE HOLDING COMPANY AND RATEPAYERS WHEN MAKING ITS DECISION TO SHUT DOWN THE GANNON UNITS EARLY?

A: Yes. Numerous data responses indicate Tampa Electric's knowledge and concern over the impact of the decisions. In addition, many of the analyses clearly show ratepayer costs and holding company savings. The following are just a few excerpts from data responses provided by the Company:

Bates Stamp	Excerpt
3049	Why these changes are necessary: In support of and to contribute to the challenges being faced by our Company.
3534	With the original December 2004 Gannon shut down date, there were no pending layoffs projected. However, now with the Base Case (#9) dates, significant reclassifications and layoffs are projected.
4814	Reduction to Achieve 2003 & 2004 Plug…Gannon – Accelerated Shutdown
4814	Gannon – Accelerated Shutdown (Implementation) • Units 1 & 2 – Shutdown with Bayside 1 Start-up • Units 3 & 4 – Shutdown September 1, 2003 (Anticipates depletion of available funding)
203	Under the Gannon early closure look, what are the impacts to earnings and ROE….what are ratepayer impacts? What are the components that will impact the fuel clause?
15	Rate base removal/Gannon base rate adj? -What would be potential impact? Earnings ROE -Argue immediate replacement of asset (BS1) * - Needs to be linked dates - must run argument -Lead to ratecase? Ratepayer impact – what goes thru fuel clause? Filing of 2003 rates on Sept. 20
797/812	Cons…1994 test year of Gannon Station included in base rates. Strong potential for base rate reduction in 2003.
2239	Since Gannon was required to reduce the 2003 budget by $1.3 M in order to meet the TEFIS assumption, the reduction has to come from these units.
200	PPA Strategy Meeting… Issues and Points to Consider… ROE and revenue requirements without Gannon… Prepare to justify the PPA as low-cost option?... Clause impacts… Shutting down Gannon units should coincide with the beginning of the PPA term and with the first Bayside unit beginning service… Prepare for affiliate discovery requests…

Q: DO TAMPA ELECTRIC'S CONTRACTUAL RELATIONSHIPS WITH TECO ENERGY AFFILIATES AFFECT RATEPAYER COSTS?

A: Yes. As pointed out by the rating agencies, Tampa Electric has several special contractual relationships with affiliates that affect ratepayers' costs. For example, TECO Energy has an affiliate that sells coal to Tampa Electric and TECO Transport provides Tampa Electric's coal transportation. The cost of the coal and its transportation is run through the fuel cost recovery clause. In addition, Tampa Electric has power purchase agreements with Hardee Power Partners Limited ("HPP"). To the extent that such arrangements are made at above-market costs, TECO Energy benefits by increasing the profitability of the non-regulated affiliates, while passing-through such higher costs to Tampa Electric's captive ratepayers.

Q: TECO ENERGY HAS BEEN ATTEMPTING TO RAISE CASH BY SELLING ASSETS. HOW DO THESE CONTRACTUAL RELATIONSHIPS AFFECT THE VALUE OF ASSETS FOR SALE?

A: This strategy has the additional benefit to the holding company of making certain assets more valuable for sale while avoiding the sharing of any gains on disposition. For example, in part of its efforts to increase cash flow, TPS recently announced the sale of its interest in the HPS, noting that it "expects to record a $60-million book gain (pre-tax) on the sale and net incremental cash of approximately $110 million." (Exhibit No.____ (SLB-3)). Thus, while Tampa Electric's power purchase agreement supported the sale, Tampa Electric's ratepayers will not see any of the gain. If this facility had been owned by Tampa Electric, normally the Commission would require the utility to share the gain on the sale with ratepayers.

Q: HOW DID TAMPA ELECTRIC'S POWER PURCHASE AGREEMENT WITH HARDEE SUPPORT THE SALE?

A: The power purchase agreement is simply assigned to the new owner of the facility. Therefore, the value of the facility is directly related to the expected cash flows provided by Tampa Electric ratepayers under the agreement. Tampa Electric's witness, J. Denise Jordan, estimated that the fuel portion of the purchased power from HPP will cost $16.1 million at an average rate of approximately $.05813 per kilowatt hour. (J. Denise Jordan Document No. 2, Schedule E7). In addition to the fuel costs, Tampa Electric is paying HPP almost $20 million a year for capacity payments. Ms. Jordan's Document No. 1 does not specify the level of capacity payments to HPP; however, as shown in document Bates Stamp 11603, the capacity charge is $19,624,800. With capacity payments of $19.6 million a year, the anticipated cost of power from HPP jumps from $.05813 per kilowatthour to $.1291 per kilowatthour. While I do not have sufficient information to evaluate the reasonableness of these charges, the HPP costs are among the highest purchased power costs paid by Tampa Electric.

Q: HAS THE COMMISSION APPROVED THE HPP COSTS?

A: The original HPP contract was approved by the Commission in the early 1990's. In 1999, the Commission addressed the Hardee 2000 amendment and allowed recovery of the HPP costs in the fuel clause, but "left the door open" for future review and consideration. As explained in Order No. PSC-99-2513:

> At the present time, we find that these costs should be recovered through the fuel clause. However, if information indicating that these costs were not prudently incurred is discovered, the prudence of these costs may be raised as an issue for our consideration in a future fuel

hearing.

Q: SHOULD THE COMMISSION INVESTIGATE THE HPP POWER COSTS DUE TO THE SALE OF HPS?

A: Yes. It is my understanding that the HPP is a "cost-based" contract. In light of the gain on the sale of HPS, the Commission should review the amounts paid under the contract to assure that the costs are reasonable and reflect HPP's actual investment in the facility. The Commission should also assure that the change of ownership will not affect ratepayer costs by increasing the owner's cost, which may then be recoverable from Tampa Electric and its ratepayers.

Q: DO YOU HAVE ANY OTHER CONCERNS WITH AFFILIATE TRANSACTIONS?

A: Yes. In 2002, Tampa Electric purchased TECO-Panda Generating Company's rights to four combustion turbines being purchased from General Electric. Tampa Electric paid $62.5 million for these rights. This transaction allowed TECO Energy to shift cash from Tampa Electric to TECO-Panda Generating Company. (Exhibit No.____ (SLB-4)). Just one year later, in 2003, Tampa Electric recorded a before tax charge of $79.6 million ($48.9 million after tax) related to the cancellation of the turbine purchases. The Company expects to receive a refund of approximately $13 million from General Electric. To the extent the Company receives this refund and to the extent TECO Energy can utilize tax benefits from the write-off, the additional cash flow would be available to meet the cash needs of TECO Energy and its unregulated subsidiaries. Yet, given Tampa Electric's plans to add seven combustion turbines over the next nine years, the decision to cancel the rights to the four combustion turbines may result in higher costs to ratepayers as the additional capacity is added.

Q: PLEASE DESCRIBE THE EVENTS LEADING TO THE REQUIREMENT TO SHUT DOWN THE GANNON UNITS.

A: The Gannon plant consisted of six coal-fired steam generating boilers and associated systems located in Hillsborough County, Florida with a total nameplate generating capacity of 1301.88 MWs. On November 3, 1999, the United States Environmental Protection Agency filed a Notice of Violation alleging that Tampa Electric had violated certain requirements of the Clean Air Act ("CAA") by making modifications to the Gannon Station without obtaining the appropriate permits and that these modifications resulted in a net significant increase in emissions from Gannon Station. As explained in the Notice of Violation, the modifications, included, but were not limited to, replacement of the furnace floor of Unit 3 in 1996; replacement of the cyclone burners of Unit 4 in 1994; and replacement of the second radiant superheater of Unit 6 in 1992. The Notice of Violation also included violations at Tampa Electric's Big Bend coal facility.

On December 6, 1999, a Consent Final Judgment ("CFJ") was entered into with the Florida Department of Environmental Protection ("DEP"). The CFJ called for shutting down the Gannon Station three years before the previously expected retirement date. Company witness, Mr. Whale, indicated that the CFJ incorporated the same requirements as the

Consent Decree negotiated between Tampa Electric and the United States Environmental Protection Agency.

On February 29, 2000, the United Stated District Court, Middle District of Florida, approved the Consent Decree negotiated between Tampa Electric and the United States Environmental Protection Agency. (Exhibit No. ____(SLB-5). The Consent Decree required, among other things, that (i) Tampa Electric repower 550 MW of Gannon coal-fired capacity with 200 MW being repowered on or before May 1, 2003 and the remainder being repowered on or before December 31, 2004 and (ii) Tampa Electric shut down and cease any and all operation of all six Gannon coal-fired boilers with a combined capacity of not less than 1194 MW on or before December 31, 2004.

Q: WHAT IMPACT DOES THE COMPANY'S DECISION TO SHUT DOWN THE GANNON UNITS EARLY HAVE ON THE COMPANY'S REQUESTED FUEL COST RECOVERY IN THIS CASE?

A: As noted by the Commission in Order No. PSC-03-0400-PCO-EI, the decision to shut down the Gannon units early resulted in a decrease in coal-fired generation. At that time, the Commission estimated the cost of replacement power costs for 2003 to be approximately $26 million. The Commission stated:

> ...we find that the reasons for, and the cost effectiveness of, Tampa Electric's decision to cease operations early at Gannon Units 1-4 should be fully explored before we can authorize Tampa Electric to recover the $26 million in associated replacement power costs. (Order No. PSC-03-

0400-PCO-EI at page 6).

The Commission further noted that the decision to cease operations early at Gannon Units 1 through 4 was a decision within the utility's control and recognized that this decision might enhance Tampa Electric base rate earnings. The Commission explained:

> We believe that the total economic effect on both base rate earnings as well as fuel costs should be evaluated in determining the prudence of the early shutdowns of Gannon Units 1-4. (Order No. PSC-03-0400-PCO-EI at page 7).

Q: WHAT REASONS DID TAMPA ELECTRIC GIVE FOR ITS DECISION TO SHUT DOWN THE GANNON UNITS PRIOR TO THE REQUIRED DATE OF DECEMBER 31, 2004?

A: First, to meet the May 1, 2003 in-service date for Bayside Unit 1, Gannon Unit 5 had to be shut down. Given that the repowering of Unit 5 to Bayside Unit 1 met the requirements of the Consent Decree and the Consent Final Judgment, the remainder of the units were not required to be shut down prior to December 31, 2004. Tampa Electric, however, determined that the planned in-service date for Bayside Unit 2 would be January 15, 2004, requiring an earlier shutdown of Gannon Unit 6. The decision was also made to shut down Units 1 through 3 earlier than the required date of December 31, 2004. According to Company witness, Mr. Whale, Tampa Electric evaluated various conditions to determine when to shut down the units, including the timing of Bayside construction activities, reliability and safety of units 1 through 4, maintenance costs and planned outage times, employee issues, reserve margin requirements, and transmission constraints. Mr. Whale also noted that Tampa Electric made a determination that it would attempt to keep the units running as long as possible without incurring significant expenditures for preventive maintenance work. Mr. Whale also explained that Tampa Electric ran multiple scenarios to evaluate ratepayer impacts, operation and maintenance impacts, and wholesale sales opportunities for off-system sales.

Q: DID THE COMPANY PRESENT SUFFICIENT EVIDENCE IN ITS FILING TO ALLOW THE COMMISSION TO DETERMINE THE TOTAL ECONOMIC EFFECT ON BASE RATE EARNINGS AND FUEL COSTS?

A: No. Company witness, Mr. Benjamin F. Smith, argued that it is neither feasible nor appropriate to isolate and then attribute costs to a single variable, such as the shutdown of the Gannon units. While he makes the argument that the costs cannot be isolated, he still concludes that the energy purchases to supplement generation due to the shutdown of Gannon Units 1 through 4 are reasonable. He also notes that Tampa Electric will have to make a 50MW firm capacity commitment for the summer of 2004, but does not provide the cost of that commitment. Neither Mr. Smith, nor any other Tampa Electric witness, provided any calculations of the replacement costs actually incurred or anticipated as a result of the early shutdown of the units.

Tampa Electric's witness, Mr. Whale, provides the only testimony regarding O&M savings, noting that Tampa Electric would need to incur "additional" O&M expenses of approximately $57 million to try to keep Units 1 through 4 operating somewhat reliably.

Q: HAS TAMPA ELECTRIC PROVIDED COPIES OF ANY ANALYSES PERFORMED?

Q: HAS TAMPA ELECTRIC PROVIDED COPIES OF ANY ANALYSES PERFORMED?

A: Yes. In response to OPC Requests for Production of Documents, Tampa Electric provided numerous analyses of various operating and shutdown scenarios. None of the scenarios represented the actual shutdown plan currently contemplated by Tampa Electric. In the initial "round" of evaluations, there were 11 scenarios. A review of the assumptions under those scenarios shows that Scenario 9 was the closest scenario to the final shutdown dates described by Witnesses Jordan and Whale. In the next round of evaluations, Tampa Electric evaluated 5 options. A review of the assumptions under those options shows that Option 5 was the closest to the final shutdown dates.

Q: WHAT WERE THE 2003 AND 2004 OPERATING AND MAINTENANCE COST PROJECTIONS FOR GANNON?

A: [redacted].

Q: DID TAMPA ELECTRIC DETERMINE THE COST TO KEEP THE UNITS RUNNING THROUGH THE REQUIRED SHUTDOWN DATE OF DECEMBER 31, 2004?

A: [redacted]

[redacted]

Q: DO YOU HAVE ANY CONCERNS REGARDING THE COMPANY'S ESTIMATE OF O&M SAVINGS AS SHOWN ON BATES STAMP 1187?

A: Yes. A review of the average O&M for the Gannon station, as reported in Tampa Electric's 2002 Federal Energy Regulatory Commission Form 1, over the last 5 years shows that O&M, excluding fuel costs, were as follows:

FIVE YEAR HISTORY OF GANNON OPERATING AND MAINTENANCE EXPENSES (EXCLUDING FUEL)			
Year	Operating	Maintenance	Total O&M
1998	$10,031,664	$23,508,659	$33,540,323
1999	$9,822,080	$22,141,702	$31,963,782
2000	$11,145,091	$24,435,680	$35,580,771
2001	$10,667,859	$24,148,779	$34,816,638
2002	$10,103,336	$29,910,813	$40,014,149
Average	$10,354,006	$24,829,127	$35,183,133

Tampa Electric has provided several documents showing that the projected 2003 O&M expenses for Gannon are [redacted]. Based on a simple comparison of the historical O&M costs and the projected 2003 O&M, Tampa Electric's estimate of [redacted] in

O&M savings appears reasonable. However, based on the testimony of Tampa Electric's witness, Mr. Whale, it would appear that Tampa Electric expected much higher-than-normal O&M costs if it were to keep Units 1 through 4 operational through December 31, 2004. Mr. Whale indicated that Tampa Electric would need to incur additional maintenance expenses of $57 million to keep the Gannon Units 1 through 4 operating "somewhat reliably" through 2004.

Q: WHAT ARE THE TOTAL O&M SAVINGS THAT WILL ACCRUE TO THE COMPANY FOR 2003 AND 2004 DUE TO THE GANNON SHUTDOWN?

A. As shown on Mr. Whale's Exhibit No. WTW-2, pages 2 and 3, the incremental Gannon Unites 1 through 4 O&M costs for 2003 would be $35.43 million and the estimated O&M costs for 2004 would be $22 million, for a total of $57.43 million that should have been incurred if the units had not been shut down. Subtracting the 2004 estimated O&M with the shutdown of [redacted] million (4/5 of TECo's estimate of [redacted] million per Bates Stamp 2082), yields savings of [redacted] million to TECo for the shutdown of Units 1 through 4. Based on average O&M costs for 1998 through 2002, the estimated costs for Unit 6 without the shutdown is $11.73 million. Subtracting the 2004 estimated O&M with the shutdown of [redacted] million (1/5 of TECo's estimate of [redacted] million per Bates Stamp 2082) yields savings of [redacted] million for the shutdown of Unit 6. The total savings due to the shutdown of Units 1 through 4 and Unit 6 is thus [redacted] million.

Q: DO YOU HAVE ANY CONCERNS WITH THE FUEL COST IMPACTS ESTIMATED BY THE COMPANY ON THE RESPONSE LABELED AS BATES STAMP 1187?

A: [redacted]

Q: PLEASE EXPLAIN.

A: Exhibit No. ____(SLB-6) is a calculation of the estimated replacement power costs associated with the Gannon shutdown. In 2002, the Gannon Units had net generation of 4,814,986 MWhs. Using this level of generation as a base and applying the Gannon shutdown dates results in replacement energy of 1,926,049 MWhs. On Schedule E4, the average cost of generation from Bayside is estimated to be $.046 per kWh, while the average cost of generation from Gannon is approximately $.0214 per kWh, based on 2002 actual expenses. Fuel costs, then, more than double when Gannon generation is replaced by gas-fired generation. At the differential of $.0246 per kWh, the replacement fuel costs for 2003 would be approximately $47.4 million. When added to Tampa Electric's estimate of [redacted] in coal contract penalties and [redacted] in dead freight charges, the cost to ratepayers will be approximately [redacted]. Although Tampa Electric did not include the coal contract penalties and dead freight charges in its current cost recovery calculations, it has indicated that these costs would be included in the subsequent true-up calculations.

Q: WHAT IS THE EXPECTED REPLACEMENT COST OF ENERGY IN 2004?

A: Assuming replacement of 100% of Gannon generation in 2004, the expected replacement cost of energy would be $118,604,917 (4,814,986 MWhs X $24.60) before any dead freight costs and coal contract penalties.

Q: HAVE YOU CALCULATED THE REPLACEMENT COST OF ENERGY FOR UNITS 1 THROUGH 4 AND UNIT 6 ONLY?

A: Yes. Since Tampa Electric was required to shut down one unit by May 31, 2003 and chose to shut down Unit 5 to repower to Bayside 1, I determined the cost associated with replacement energy on Units 1 through 4 and Unit 6 to isolate the costs associated with the shutdown of these units. The replacement costs for Units 1 through 4 would be $24.5 million and $56.5 million for 2003 and 2004, respectively. The replacement costs for Unit 6 would be $2.4 million for 2003 and $39.7 million for 2004.

Q: WHAT OTHER COSTS HAVE BEEN INCURRED BY THE EARLY SHUTDOWN OF UNITS 1 THROUGH 4?

A: As explained by Tampa Electric witness Mr. Smith, Tampa Electric is projecting that it will purchase 50 MW of firm capacity for its summer 2004 reserve margin requirement. If Gannon Units 1 through 4 were kept operational until the required December 31, 2004 date, then this purchase would not be required.

In addition, as shown in Tampa Electric's 2004 Fuel Procurement and Wholesale Power Purchases Risk management Plan, Tampa Electric has incurred additional hedging costs due to its implementation of a hedging plan in 2003 in response to the need for an increase amount of natural gas due to repowering of Gannon. In accordance with the Commission's policy, Tampa Electric's incremental hedging costs are passed through the fuel adjustment clause.

Q: DO YOU HAVE A RECOMMENDATION REGARDING TAMPA ELECTRIC'S REPLACEMENT FUEL COSTS?

A: Yes. I believe it would be just and reasonable for the Commission to require Tampa Electric to offset its replacement power costs by [redacted] million in O&M savings. This would be a fair and equitable result because (i) the decision to shut down the units early was a voluntary decision by the Company within its control; (ii) the requirement to shut down the units by the end of 2004 was a direct result of claimed violations by the United States Environmental Protection Agency, (iii) the ratepayers will suffer continued harm through additional replacement power costs from 2005 through 2007, (iv) the ratepayers have also paid Tampa Electric for the environmental modifications which were challenged by the EPA; and (v) TECO Energy has benefited by contractual relationships between its subsidiaries, including recognition of a gain on the sale of HPS which is not shared with the ratepayers.

Q: HAS THE COMMISSION EVER ALLOWED UTILITIES TO USE COST RECOVERY CLAUSES TO CHARGE CUSTOMERS FOR ITEMS THAT WOULD NORMALLY ONLY BE AUTHORIZED THROUGH A BASE RATE ADJUSTMENT AFTER A "FULL BLOWN" GENERAL RATE CASE?

A: Yes. The Commission has allowed the recovery of security costs and incremental hedging costs through adjustment clauses. In addition, environmental costs are recovered through the Environmental Cost Recovery Clause. In 1998, Tampa Electric was allowed to recover the $90 million cost of a new scrubber at Big Bend 1 & 2 that the Company indicated would solve most of the requirements of Phase II of the Clean Air Act Amendments. In addition, Progress Energy is currently being allowed to recover operating, maintenance, and capital costs associated with its Hines Units 2 to the extent of fuel savings. Using this logic, it would seem appropriate to give customers credit in the fuel clause for associated savings Tampa Electric realizes in O&M expenses.

Q: THE COMPANY RECENTLY REQUESTED ACCELERATION OF DEPRECIATION AND DISMANTLEMENT CHARGES ON GANNON. SHOULD THE COMMISSION

RECOGNIZE THESE CHARGES AS REDUCTIONS IN SAVINGS ACCRUING TO SHAREHOLDERS?

A: No. Annual depreciation charges for Gannon have been $23.2 million. Earlier this year, Tampa Electric was given the authorization to accelerate depreciation to assure full depreciation of the Gannon Units by the end of 2003, subject to a final hearing on the issue in November. As a result, Tampa Electric's earnings for 2003 will be reduced by an additional $22.9 million. Expenses for 2004 will thus be $23.2 million less than 2002 and $46.1 million less than in 2003.

In addition to the annual depreciation charges, Tampa Electric has been accruing $5.8 million a year for dismantlement. Earlier this year, in Docket 030409-EI, the Company requested an increase in the dismantlement accrual of $2.2 million, for a total of $7.987 million. Prior to 2003, the portion of the $5.8 million accrual attributable to Gannon was $711,297; however, Gannon represents $7.4 million of the 2003 accrual. If this accrual is discontinued in 2004, Tampa Electric's dismantlement accrual will decrease to $627,925. This is a reduction of $5.1 million from the pre-2003 accrual.

While Tampa Electric's earnings for 2003 will be suppressed as a result of these additional accruals, the accruals do not affect cash flow. The accruals do, however, affect Tampa Electric's surveillance reporting, allowing Tampa Electric to show a reduced level of earnings. In 2004, this situation will reverse.

Until base rates are modified, customers will continue to pay the charge attributable to Gannon depreciation set in the last general rate case. The net result of the acceleration will be a decrease to Tampa Electric's earnings of $25.1 million in 2003 and an increase of $28.3 million in 2004. Therefore, over the two year period, there is a positive impact of $3.2 million on earnings and zero impact on cash flow.

Q: DO YOU HAVE ANY OTHER ISSUES THAT THE COMMISSION SHOULD CONSIDER IN ITS EVALUATION OF TAMPA ELECTRIC'S FUEL FILING?

A: Yes. The Commission should review the balance in the dismantlement accrual account for Gannon and determine whether it would be appropriate to utilize a portion of this regulatory liability to cover a portion of the expenses associated with early shutdown. In the FPSC Staff Recommendation filed on May 22, 2003 in Docket No. 030409-EI, Staff noted that the Company's current estimate of dismantlement base costs is $40.7 million. A Tampa Electric document in that docket shows total dismantlement costs of $32.12 million. (Exhibit No. ____(SLB-7)). The [redacted] million in O&M savings calculated earlier in my testimony was based on the Company's estimate of [redacted] million and [redacted] million in 2003 and 2004 O&M costs, respectively. To the extent any of these costs are associated with dismantlement activities, those costs should be covered by Tampa Electric from the dismantlement account. The savings and the fuel cost offset should then be adjusted accordingly.

Q: SHOULD THE COMMISSION REFLECT BAYSIDE COSTS IN THE CALCULATION OF SAVINGS?

A: No. The issue of the Bayside addition is more complex than can, or should, be handled in the context of this proceeding. While the Bayside units are utilizing portions of the Gannon 5 and 6 facilities, the addition of the Bayside units is not intended as simply a replacement for the Gannon units. Even without the retirement of the Gannon Units, the Company would need additional capacity to meet its 20% reserve margin requirement. The addition of the Bayside units provides 515 MW of additional capacity over the amount retired at Gannon. Tampa Electric shows generation from Bayside Units 1 and 2 at approximately 7,874,000 kWh's a year, which is significantly higher than the generation from the Gannon Units.

Further, Tampa Electric laid off approximately 7% of its work force in 2002. (Exhibit No. ___(SLB-8). In addition, a full-blown rate case would include the elimination of the Gannon rate base, depreciation, and dismantlement accruals that were included since the last base rate case. Other issues that would be addressed would include the numerous dealings with TECO Energy affiliates.

The Gannon O&M savings are, however, directly attributable to the early shutdown of the units and the imposition of replacement energy costs on Tampa Electric's ratepayers.

Q: PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A: I recommend that the Commission offset Tampa Electric's requested fuel cost increase by the O&M savings from the shutdown of the Gannon Units.

The total savings to Tampa Electric would be [redacted] million which should be used to offset the replacement fuel costs. The recommended Fuel and Purchased Power Cost Recovery Factor would then be calculated as follows:

[redacted]

I also believe the concerns I have expressed in this testimony support additional Commission investigation of:

(i) amounts paid to HPP under the power purchase agreement to assure that the costs were cost-based due to the recognition of a gain on the sale of HPS which was supported by the power purchase arrangement; and

(ii) the HPP agreement to assure that the change of ownership will not affect ratepayer costs due to the revised costs of the new owner.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

BY MS. KAUFMAN:

Q Ms. Brown, have you prepared a summary?

A Yes, I have.

Q If you would give it now. Thank you.

A Thank you. My testimony addresses the reasonableness of the extraordinary rate increase caused by the shutdown of Tampa Electric's Gannon coal units and offers the Commission a fair and equitable method to mitigate this increase.

In the Commission's order on Tampa Electric's request for a midcourse fuel correction, the Commission recognized that the shutdown of the Gannon Units caused an increase in fuel costs and that the decision to cease operations early was within Tampa Electric's control and might enhance Tampa Electric's base rate earnings.

The Commission indicated that the economic effect on both base rate earnings and fuel costs should be evaluated. My testimony addresses the impact of the Gannon shutdowns. I first describe the financial situation faced by TECO Energy to show the environment in which Tampa Electric made its decision to accelerate the shutdown of the Gannon units. I provide a calculation of the rate increases that are absorbed by the ratepayers through the fuel clause due to acceleration of the shutdown. I then provide an estimate of the savings and operating and maintenance expenses that will accrue to Tampa Electric due to the shutdown.

Lastly, I offer the Commission a balanced approach to protect ratepayers from the extraordinary fuel rate increase caused by the decision to accelerate the Gannon shutdown, while allowing the company to recover its net increase in costs associated with the shutdown.

Tampa Electric's ratings have been downgraded along with the ratings of TECO Energy. In making these downgrades, the rating agencies have pointed to the lack of restrictions on cash flow between Tampa Electric and TECO Energy. This financial situation has resulted in the significant need for cash which can be derived from Tampa Electric's earnings. This is the environment in which Tampa Electric made its decision to accelerate the Gannon shutdowns.

My testimony provides examples of how the financial health of Tampa Electric has supported TECO Energy's other operations. One example I provide is Tampa Electric's $62.5 million purchase of TECO Panda Generating Company's rights to four General Electric combustion turbines with subsequent cancellation of the purchase resulting in a $48.9 million after-tax write-off.

Another example is Tampa Power System's recent sale of its interest in Hardee Power Partners, which resulted in a $60 million pretax gain, a net incremental cash of $110 million.

I also expressed my concern that the cost under the

Hardee Power contract may increase as a result of the new ownership, and my concern that a cost-based contract would lead to a $60 million gain.

To provide the Commission with the information needed to perform an economic evaluation of the impact of the Gannon shutdown, I calculated the rate increase associated with the replacement fuel cost over 2003 and 2004. I then calculated the savings and operating and maintenance expenses over the same time period. Based on these calculations, ratepayers will bear the burden of a $166 million rate increase for fuel cost, while the company will enjoy substantial operating and maintenance expense savings. The amount of the company's savings is confidential, but it's included in the confidential information that was just handed to you. If you'll look at Page 25, Line 17.

In my testimony I recommend that the Commission require Tampa Electric to offset the fuel rate increase with the money it saved from the early shutdown. This is a fair and reasonable approach to both the ratepayers and the company. It recognizes the circumstances leading to the Gannon shutdowns and the extraordinary financial impact the early shutdown has had and will continue to have to ratepayers, but allows the company to recover its replacement fuel cost in excess of the operating and maintenance expense savings. Without the offset, the company will unfairly benefit from its decision to accelerate the shutdown of the Gannon Units, while ratepayers are harmed by the extraordinary increase in fuel cost.

In conclusion, I'm recommending that the Commission require Tampa Electric to reduce the extraordinary rate increase it has requested by the amount of the operating and maintenance expenditures that it will avoid as a result of the accelerated shutdown.

Q Does that conclude your summary?

A Yes, it does.

MS. KAUFMAN: Ms. Brown is tendered for cross-examination.

CHAIRMAN JABER: Thank you, Ms. Kaufman.

Mr. Vandiver, Mr. LaFace, should I assume you have no questions of this witness?

MR. VANDIVER: No questions.

CHAIRMAN JABER: Mr. Hart.

MR. HART: Yes, ma'am.

CROSS EXAMINATION

BY MR. HART:

Q Ms. Brown, in your prefiled testimony and in your summary you attempt to raise certain questions about the sale of Hardee Power Partners; is that correct?

A Yes, it is.

Q Isn't it also correct that in your testimony you do not testify or even attempt to establish that Tampa Electric's ratepayers have, in fact, paid more or will pay more from power purchased from Hardee Power Partners after the sale than they did before the sale?

A Could you repeat the question, please?

Q Isn't it correct that in your testimony you do not testify or even attempt to establish that Tampa Electric's ratepayers have, in fact, paid more or will pay more for power purchased from Hardee Power Partners after the sale than they did before the sale?

A Yes. It's impossible to know at this time if the cost will actually rise as a result of the sale. I believe the contract does have open-ended, an open-ended ability for the new owner to substitute its costs into the costs that would have been incurred by Hardee Power Partners and, therefore, I do believe that there is an opportunity for those costs to increase. That's the issue that I raised.

Q But the answer to the question I asked you was yes; is that correct?

A Yes. I did not attempt to put a number on that.

Q Well, you, in fact, did not only not put a number on it, you didn't attempt to actually establish that it's, in fact, higher, did you?

A I did not attempt to establish that it's higher because we don't have any history of that at this point in time.

Q Now in your testimony you deal with the issue of what you believe are the difference in fuel costs between running the Gannon Units and Bayside 1 with running the Gannon Units and Bayside 1 and 2; is that correct?

A No. I calculate the difference between the -- all I calculated was the replacement cost associated with losing the Gannon generation. And I calculated it based on the difference between the Gannon cost per kilowatt hour of fuel and the cost of gas under the Bayside Units using the $46 a megawatt hour as a proxy.

Q If we look on Page 20 of your testimony, you have a number on Line 10 that purports to be the impact on ratepayers from the decisions made by the company to retire the Gannon Units; is that correct?

A That number is a 2003 number only. It does not reflect 2004. It also reflects dead-freight charges and coal contract penalties, which, based on Ms. Jordan's testimony, may or may not happen.

If you want to look at the fuel cost isolated, you would look at the number on Line 8 and add it to the number on Line 15.

CHAIRMAN JABER: Ms. Brown, may I interrupt here for a minute?

I specifically heard Ms. Jordan say repeatedly that the dead-freight charges will not occur; not may or may not, but will not occur, cannot occur because there are no dead-freight charges. How does that -- again, without revealing any confidential information, that must change your testimony.

THE WITNESS: I still have a concern because, number one, we have not addressed the issue of the coal contract yet, the transportation contracts and the coal contracts yet. I believe that's been deferred to a different proceeding.

However, because there were coal contract penalties and dead-freight charges, and it's my understanding now that they have been negotiated away, that would imply to me that maybe those costs are being recovered under a different name in a different contract.

So whether there are still some implications as to additional costs that will be incurred for the ratepayers or not is not known at this time to me.

CHAIRMAN JABER: Mr. McWhirter specifically asked her if those dead-freight charges allegedly, if there are dead-freight charges, could be recovered elsewhere. And she came back and pretty affirmatively said there are no dead-freight charges. Are you just not convinced by that testimony? It's okay if you're not. I just -- I need to understand what you heard versus what you didn't hear.

THE WITNESS: I am convinced that they're no longer calling dead-freight charges. But when you have a settlement, my experience has been that you can move numbers in a settlement into any, any particular bucket of cost. Whether the company was willing to give up this number that you see in my testimony on Line 9, whether they're willing to just give up that number and say, fine, that goes away, or whether they're saying, fine, we'll recover it over in another name, I don't know. I haven't looked at that.

I am -- to me, I'm indifferent as to whether the number is zero or it's the number that shows up in my testimony. I believe that the fuel cost numbers that you see on Line 8 and again on Line 15 are very sufficient anyway without those costs to show that replacement fuel costs have been extremely high.

CHAIRMAN JABER: Okay. And my final question though as we sit here today and for what we have to do in this proceeding, not for the issues that are deferred, there was nothing in Ms. Jordan's testimony you heard today that indicates dead-freight charges will be included. I understand your suspicions, but that's not my question.

THE WITNESS: Not in Ms. Jordan's testimony. But I will have to say that in Ms. Wehle's testimony she testified there would be no 2003, but I was not quite sure what she intended for 2004. It sounded like there could potentially be some cost in 2004.

CHAIRMAN JABER: Okay.

BY MR. HART:

Q Then the number that you have on Line 10 is really not a number that you can testify, in fact, as being accurate. It's a number that's based on what you don't know rather than what you do know.

A It is the number based on what Tampa Electric had estimated in many of their data responses. To the extent that that number changes, whether it goes up or down or becomes zero, it's my understanding that in Ms. Jordan's original testimony she had said that those costs they would request would be flowed through the fuel adjustment charge, whatever they turned out being.

Q So as we sit here today, you just simply don't know whether or not the number on Line 10 is accurate?

A Again, I would look at the number on Line 8 and the number on Line 15. The number on Line 10 simply adds those coal contract penalties and dead-freight charges. You can either assume that they're in or out. Either way, the replacement costs are substantial.

CHAIRMAN JABER: So the answer to the question is no.

THE WITNESS: No. I can't guarantee, even if, even if she said they were going to still have coal contract penalties and dead-freight charges, these are estimates because they didn't include them in their, in their current cost calculations. They said whatever they were would then come into play later when they actually knew what they were.

BY MR. HART:

Q Well, let me ask it another way. If it turns out there are no dead-freight charges and no coal contract penalties, the number on Line 10 is overstated.

A For 2003, yes.

Q Yes. Now with regard to the number on Line 8, that is your calculation; is that correct?

A Yes, it is.

Q And it's calculated using some numbers that you, that were calculated by Tampa Electric; is that correct?

A It's calculated providing, using information provided by Tampa Electric. Yes.

Q And what you've done there, in fact, is run a scenario with Bayside 1 running and the Gannon Units running versus the scenario with the Gannon Units shut down early; is that correct?

A No.

Q Tell me what the two scenarios were.

A The -- there weren't really two scenarios. All I did was look at the amount of Gannon generation. I used 2002 as a proxy, which was actually lower than other years, other previous years. And then I calculated what the kilowatt hour generation would be for Gannon over the 2003 and the 2004 time frame, assuming the, the dates of shutdown.

I then applied the cost of gas using the Bayside cost as a proxy, the $46 a megawatt hour as a proxy, and compared it to the cost of Gannon generation. The differential is, is what I used to calculate the numbers on Line 8 and, again, on Line 15.

Q And how is that different than saying that what you've done here is calculate two scenarios, one with the Gannon Units running and one without, the Gannon Units not running?

A Your question referred to Bayside, and this didn't have, my calculations didn't have anything to do with Bayside particularly other than using the cost of Bayside as a proxy.

Q Okay. So, so it's your testimony then this is the cost of -- it's the impact on the ratepayers from not running the Gannon Units; is that correct? Is that how you would say it?

A Yes, that's correct.

Q And in order to make that calculation, you, you had to know the cost of running the Bayside Units for fuel; is that correct?

A No. I could have made the calculation using purchased power costs, but I chose to use the Bayside costs simply because they were lower and I felt like it was conservative.

Q In making your calculation, you used the cost of running Bayside, is that correct, for fuel?

A Yes. I used the cost for Bayside.

Q Okay. Now that cost for running Bayside was a number that you got from information provided by Tampa Electric; is that correct?

A Yes, it was.

Q And that number was the number Tampa Electric calculated when they ran Bay, when they projected to run Bayside Units 1 and 2; isn't that correct?

A It was either Bayside 1 or 2. They both had approximately $46 per megawatt hour.

Q Right. And you now understand, don't you, that part of that cost for running Bayside 1 and 2 is a fixed charge, not a variable charge?

A I understand that it has transportation costs in it. I believe that in the term that we're talking about, that the transportation costs themselves were variable.

Q And you also understand that, if that's true and Bayside 2 doesn't run, the cost of running Bayside 1 will be higher; isn't that correct?

A I would have to look at your transportation contracts and when you entered into those and what the terms and conditions of those are.

Q Well, if that's true, wouldn't the, wouldn't you have overstated the impact on customers of running the Gannon Units?

A No, I don't believe that I would have. I believe the $46 is a very good proxy, especially when looking at your other costs.

Q But that would be a change in your methodology; you would now be using a number that's a proxy, not -- you would not be using the Bayside projected costs for 2004, would you?

A I used the Bayside costs for 2004 as a proxy. It was a proxy.

Q Okay. But if you, if you find out that that number is different than what you thought it was, you're still going to use the same number as a proxy.

A Not necessarily. I would look at the totality of all of the replacement costs that Tampa Electric would, would have. I may choose to use something completely different. I may choose to modify the number.

Q If, in fact -- if there's a fixed charge for the gas for Bayside 2, then the impact on ratepayers is overstated in Line 8; isn't that correct?

A No.

Q Well, it assumes that the cost of running Bayside 2 can be avoided, doesn't it?

A No, that's not what it assumed.

Q Well, well, then this -- it's -- this is not the impact on running the Gannon Units and Bayside. It's just the impact, you think, of running the Gannon Units?

A No. It's the impact of not running the Gannon Units.

Q And it disregards any increases in cost that may happen as a result of that?

A No. It actually calculates what the increase in cost would be using the Bayside cost, delivered cost as a proxy as opposed to using the higher purchased power cost.

Q Yes. But you have to use a different proxy than the one projected by Tampa Electric for running Bayside to reach that conclusion.

A No, I don't have to. I'm using the Bayside cost as a proxy. Bayside -- I looked at that as being the most likely replacement value.

CHAIRMAN JABER: Mr. Hart, I'm looking for a break point. I don't want to interrupt your train of thought, but this seems like -- since you paused for a moment.

MR. HART: Okay. That will be fine.

CHAIRMAN JABER: Okay. Commissioners, I propose we take a lunch break and come back at 1:15. Okay. We'll do that. We'll come back at 1:15.

(Recess taken.)

(Transcript continues in sequence with Volume 6.)

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

I, LINDA BOLES, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 21st DAY OF NOVEMBER, 2003.

Linda Boles

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