BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR. — DOCKET NO. 060001-EI

PETITION TO RECOVER NATURAL GAS STORAGE PROJECT COSTS THROUGH FUEL COST RECOVERY CLAUSE, BY FLORIDA POWER & LIGHT COMPANY. — DOCKET NO. 060362-EI

PETITION FOR AUTHORITY TO RECOVER PRUDENTLY INCURRED STORM RESTORATION COSTS RELATED TO 2004 STORM SEASON THAT EXCEED STORM RESERVE BALANCE, BY FLORIDA POWER & LIGHT COMPANY. — DOCKET NO. 041291-EI

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VOLUME 4

Pages 562 through 657

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN LISA POLAK EDGAR
COMMISSIONER J. TERRY DEASON
COMMISSIONER ISILIO ARRIAGA
COMMISSIONER MATTHEW M. CARTER, II
COMMISSIONER KATRINA J. TEW

DATE: Tuesday, November 7, 2006

TIME: Commenced at 9:35 a.m.

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

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

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
44	CA-1	567	567
45	CA-2	567	567
46	CA-3	567	567
47	WAS-1	602	602
48	WAS-2	602	602
50	DWG-1	630	
51	DWG-2	630	
52	DWG-3	630	

(Transcript continues in sequence from Volume 3.)

MR. BEASLEY: Thank you. We would call as our next witness Mr. Carlos Aldazabal.

MS. BENNETT: For a matter of clarification, I'm not sure that we entered the exhibits into the record for Ms. Wehle.

CHAIRMAN EDGAR: We just did. But that's okay. Always ask.

MR. BEASLEY: As we indicated yesterday, all of Mr. Aldazabal's issues have been stipulated. And we would propose to stipulate the entry of his testimony into the record and the admission into evidence of his exhibits.

We have committed to make him available for questions regarding Tampa Electric's treatment of gas storage costs, and for that reason we've called him to the stand. But if I could propose that we simply stipulate in his testimony and exhibits, I could, I could identify them and then we could tender him for questions regarding gas storage costs, if that would work.

CHAIRMAN EDGAR: Is there any objection?

MS. CHRISTENSEN: No objection.

MR. McWHIRTER: No questions from FIPUG.

CAPTAIN WILLIAMS: No questions.

MS. BENNETT: No objections.

MR. BEASLEY: Thank you. His testimonies include the March 1, 2006, final true-up testimony as amended by a filing made on October 9, 2006; his August 8 actual/estimated true-up testimony; his projection testimony for 2007 filed on September 1, 2006, as amended on October 9, 2006, with revised Pages 9 and 10 filed on October 30, 2006. His exhibits include Exhibits CA-1 that accompanied his March 1, 2006, testimony marked Exhibit 44 in the staff's comprehensive list of exhibits; Exhibit CA-2 attached to his August 8th actual/estimated true-up testimony, and that's marked Exhibit 45 in staff's composite exhibit list; and Exhibit CA-3 attached to his September 1, 2006, projection testimony marked Exhibit 46 in staff's comprehensive list of exhibits.

CHAIRMAN EDGAR: The prefiled testimony as described and exhibits marked 44, 45, and 46 will be entered into the record.

MR. BEASLEY: Thank you.

(Exhibits 44, 45 and 46 marked for identification and admitted into the record.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 060001-EI
FILED: 3/1/06

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

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

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

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

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2005 through December 2005 for both the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause ("capacity clause"). I also present the wholesale incentive benchmark for January 2006 through December 2006 as well as the actual incremental operation and maintenance ("O&M") security alert and hedging expenses for the period January 2005 through December 2005.

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

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

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

CAPACITY COST RECOVERY CLAUSE

Q. What is the final true-up amount for the Capacity Cost Recovery Clause for the period January 2005 through December 2005?

A. The final true-up amount for the capacity clause for the period January 2005 through December 2005 is an under-recovery of $156,806.

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

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 2005

Through December 2005", provides the calculation for the final under-recovery of $156,806. The actual capacity cost under-recovery, including interest was $1,114,118 for the period January 2005 through December 2005 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $957,312 actual/estimated under-recovery approved in PSC Order No. PSC-05-1252-FOF-EI issued December 23, 2005 in Docket No. 050001-EI, results in a final under-recovery for the period of $156,806 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 2007 through December 2007.

Q. What is the estimated effect of this $156,806 under-recovery for the January 2005 through December 2005 period on residential bills during January 2007 through December 2007?

A. The $156,806 under-recovery will increase a 1,000 kWh residential bill by approximately $0.01.

Incremental Security Alert Expenses

Q. What were Tampa Electric's actual 2005 incremental O&M 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 $342,158 for incremental O&M security expenses for measures taken by the company to protect its generating facilities for the period January 2005 through December 2005.

Q. How did the actual incremental O&M security costs compare to the costs included in the 2005 Actual/Estimated capacity filing?

A. Actual incremental O&M security costs were $58,733 lower than projected in the 2005 Actual/Estimated capacity filing. The primary reason incremental O&M security costs were lower was the renegotiation of contract rates Tampa Electric paid for guard services.

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

A. Yes. To calculate incremental security costs, Tampa Electric compared its actual total O&M security expenses to baseline expenses or pre-9/11 annual security expenses. All incremental O&M security costs were separately identified and any savings gained through the implementation of any security related projects were credited pursuant to the method described in Order No. PSC-03-1461-FOF-EI, issued December 22, 2003.

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE

Q. What is the final true-up amount for the Fuel and Purchased Power Cost Recovery Clause for the period January 2005 through December 2005?

A. The final fuel clause true-up for the period January 2005 through December 2005 is an under-recovery of $106,516,837. The actual fuel cost under-recovery, including interest, was $254,173,059 for the period January 2005 through December 2005. This $254,173,059 amount, less the $147,656,222 actual/estimated under-recovery amount approved in Order No. PSC-05-1252-FOF-EI, issued December 23, 2005 in Docket No. 050001-EI results in a net under-recovery amount for the period of $106,516,837. The 2005 hurricane season and resulting dramatic increases in the prices of fuels, particularly natural gas, were the primary drivers for the under-recovery.

Q. What is the estimated effect of the $106,516,837 under-recovery for the January 2005 through December 2005 period on residential bills during January 2007 through December 2007?

A. The $106,516,837 under-recovery would increase a 1,000 kWh residential bill by approximately $5.42.

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

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel Over/(Under) Recovery for the Period January 2005 Through December 2005". It shows the calculation of the final fuel under-recovery of $106,516,837.

Line 1 shows the total company fuel costs of $984,850,997 for the period January 2005 through December 2005. The jurisdictional amount of total fuel costs, which includes the Commission ordered waterborne coal transportation expense disallowance, is $936,449,790, 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 $255,684,832 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 $254,173,059 shown on line 8. The $254,173,059 actual under-recovery amount less the $147,656,222 actual/estimated under-recovery amount shown on line 9, results in a final $106,516,837 under-recovery amount for the period January 2005 through December 2005 as shown on line 10.

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

A. Document No. 3 entitled "Tampa Electric Company Calculation of True-up Amount Actual vs. Original Estimates for the Period January 2005 Through December 2005", shows the calculation of the actual under-recovery as compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2005 through December 2005?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost variance is $238,905,393 more than what was originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2005 through December 2005?

A. As shown on line C3 of Document No. 3, the company collected $15,259,333 or 2.2 percent less jurisdictional fuel revenues than originally estimated.

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

A. Document No. 4 contains Commission Schedules A1 through A9 for the months of January 2005 through December 2005. Also included is a twelve-month summary detailing the transactions for each of Commission Schedules A6, A7, A8, and A9 for the period January 2005 through December 2005.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2006, as derived in accordance with Order No. PSC-01-2371-FOF-EI, Docket No. 010283-EI?

A. The company's 2006 benchmark is $1,051,869, which is the three-year average of $1,227,431, $1,049,937, and $878,238 actual gains on non-separated wholesale sales, excluding emergency sales, for 2003, 2004 and 2005, respectively.

Hedging Transaction and Incremental O&M Costs

Q. Did Tampa Electric prudently incur incremental O&M expenses for initiating and/or maintaining its non-speculative financial hedging program in 2005?

A. Yes. Tampa Electric prudently incurred $164,960 for incremental O&M hedging expenses. An itemization of the incremental O&M expenses by category will be provided as an exhibit to the direct testimony of Tampa Electric witness J. T. Wehle, which will be filed April 3, 2006 in this docket.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 060001-EI
FILED: 8/8/06

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

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

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and a Masters of Accountancy in 1995 from the University of South Florida in Tampa. I am a CPA in the State of Florida and have accumulated 11 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I was promoted to Manager, Regulatory

Affairs. My present responsibilities include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2006 through December 2006 fuel and purchased power and capacity true-up amounts to be recovered in the January 2007 through December 2007 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 2006, based on six months of actual data and six months of estimated data. This information will be used to determine fuel and purchased power costs and capacity cost recovery factors for the year 2007.

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

A. Yes. I have prepared Exhibit No. ____ (CA-2), which contains two documents. Document No. 1 is comprised of Schedules E1-B, E-2, E-3, E-5, E-6, E-7, E-8, and E-9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2006 through December 2006. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2006 through December 2006. 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 2007 through December 2007 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2006 through December 2006 is an under-recovery of $157,776,979.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2007 through December 2007 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2007 is the sum of the final true-up amount for the period January 2005 through December 2005 and the actual/estimated true-up amount for the period January 2006 through December 2006.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2005?

A. The true-up was an under-recovery of $106,516,837. The actual fuel cost under-recovery, including interest and the waterborne transportation cost adjustment, was $254,173,059 for the period January 2005 through December 2005. The $254,173,059 amount, less the actual/estimated under-recovery amount of $147,656,222 approved in Order No. PSC-05-1252-FOF-EI issued December 23, 2005 in Docket No. 050001-EI results in a net under-recovery amount for the period of $106,516,837. The final under-recovery of $106,516,837 will be applied in the calculation of the fuel recovery factors for the period January 2007 through December 2007.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2006 through December 2006?

A. The actual/estimated fuel and purchased power cost recovery true-up is an under-recovery amount of $51,260,142 for the January through December 2006 period.

The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit ____ (CA-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 2006 through December 2006?

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 __ (CA-2), Document No. 1 on Schedule E1-B, line A.5b, Tampa Electric included $196,702 for actual and estimated incremental hedging O&M costs in its 2006 actual/estimated true-up calculation.

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

A. The total anticipated costs for 2006 are $365,855, 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 $365,855 of total anticipated costs, which results in an incremental expense of $196,702.

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

A. The currently projected incremental hedging O&M cost are $39,096 less than the original projected costs. The variance is primarily due to decreased labor and related charges.

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 2007 through December 2007 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2006 through December 2006 is an under-recovery of $960,951 as shown in Exhibit ____ (CA-2), Document No. 2, page 2 of 4.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2007 through December 2007 capacity cost recovery factors?

A. Tampa Electric calculated the net true-up amount to be recovered in 2007 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 2007 capacity cost recovery factors is the sum of the final true-up amount for 2005 and the actual/estimated true-up amount for January 2006 through December 2006.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2005?

A. The final true-up amount is an under-recovery of $156,806 per the company's March 1, 2006 true-up filing and as shown in Exhibit ____ (CA-2), Document No. 2, page 1 of 4.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2006 through December 2006?

A. The actual/estimated true-up amount is an under-recovery of $804,145 as shown on Exhibit ____ (CA-2), Document No. 2, page 1 of 4.

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

A. Yes. Given the Commission's previous authorization to recover incremental security O&M costs arising as a result of the extraordinary circumstances of the terrorist attacks of September 11, 2001, Tampa Electric's incremental security O&M costs are included for recovery through the capacity clause. Therefore, as shown on Exhibit ____ (CA-2), Document No. 2, Page 4 of 4, the company requests recovery of $582,991, after jurisdictional separation, for 2006 actual/estimated incremental security O&M expenses.

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

A. The actual/estimated incremental security O&M expenses are $11,901 less than the original projected costs. The variance is due to guard services that were projected but did not occur.

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

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

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

A. Yes. After adjusting the base year total by energy sales growth, the baseline that should be used to calculate 2006 incremental security costs is $2,218,979. The calculation of the baseline security O&M expense amount is shown on Exhibit ____ (CA-2), Document No. 2, page 4 of 4.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

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

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy in 1995 from the University of South Florida in Tampa. I am a CPA in the State of Florida and have accumulated 11 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, budgeting and analysis, and regulatory affairs. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I was promoted to Manager, Regulatory Affairs. My present responsibilities include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors and the projected wholesale incentive benchmark for January 2007 through December 2007. In addition, I will address the 2007 projected incremental security costs as a result of the September 11, 2001 attacks as well as the appropriate base amount and period for calculating incremental security costs. I will also describe significant events that affect the factors and provide an overview of the composite effect from the various cost recovery factors for 2007.

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

A. Yes. My Exhibit CA-3, consisting of two documents, was prepared under my direction and supervision. Document

No. 1 of Exhibit CA-3 is furnished as support for the projected capacity cost recovery factors. Document No. 2 which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, is comprised of Schedules E1 through E10 and E12 for January 2007 through December 2007 as well as Schedule H1 for January through December, 2004 through 2007.

Capacity Cost Recovery

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

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit CA-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 of capacity payments for power purchased for retail customers excluding optional provision purchases for interruptible customers through the capacity cost recovery factors.

The company is also requesting recovery of incremental security expenses as a result of the events of September 11, 2001, as authorized in previous years. As shown on Exhibit CA-3, Document No. 1, Tampa Electric requests recovery of $668,761, after jurisdictional separation, for estimated expenses in 2007.

Q. Were Tampa Electric's base year "post-9/11" security costs adjusted for retail energy sales growth as required by Order No. PSC-03-1461-FOF-EI, filed in Docket No. 030001-EI on December 22, 2003?

A. Yes. Tampa Electric's 2006 actual adjusted base year total security O&M costs were $2,218,979. After adjusting this amount for expected energy sales growth, a $2,273,344 baseline was used to calculate Tampa Electric's 2007 incremental security costs. This calculation is shown on Exhibit CA-3, Document No. 1, and page 5 of 5.

Q. Please summarize the proposed capacity cost recovery factors by rate schedule for January 2007 through December 2007.

A.

Rate Schedule	Capacity Cost Recovery Factor (cents per kWh)
Average Factor	0.271
RS	0.325
GS and TS	0.311
GSD, EV-X	0.261
GSLD and SBF	0.222
IS-1, IS-3, SBI-1, SBI-3	0.020
SL-2, OL-1 and OL-3	0.042

These factors are shown in Exhibit CA-3, Document No. 1, and page 4 of 5.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.271 cents per kWh compare to the factor for January through December 2006?

A. The proposed capacity cost recovery factor is 0.016 cents per kWh (or $0.16 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.287 cents per kWh for the January 2006 through December 2006 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the base fuel and purchased power cost recovery factor for the year 2007?

A. The appropriate amount for the 2007 period is 5.897 cents per kWh before the normal application of factors that adjust for variations in line losses. Schedule E1 of Exhibit CA-3, Document No. 2, Fuel Projection, shows the appropriate value for the total fuel and purchased power cost recovery factor as projected for the period January 2007 through December 2007.

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

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF penalty of $99,791, which is included in the calculation of the total fuel and purchased power cost recovery factors. Additionally, E1-C indicates the net true-up amount for the January 2006 through December 2006 period. The net true-up amount for this period is an under-recovery of $157,776,979.

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 2007 through December 2007.

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

A. Schedule E1-E presents the standard, on-peak and off-peak fuel adjustment factors after adjusting for variations in line losses.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by rate schedule for January 2007 through December 2007.

A.

Rate Schedule	**Fuel Charge Factor (cents per kWh)**	
Average Factor	5.897	
RS, GS and TS	5.922	
RST and GST	7.392	(on-peak)
	5.146	(off-peak)
SL-2, OL-1 and OL-3	5.483	
GSD, GSLD, and SBF	5.899	
GSDT, GSLDT, EV-X and SBFT	7.364	(on-peak)
	5.126	(off-peak)
IS-1, IS-3, SBI-1, SBI-3	5.745	
IST-1, IST-3, SBIT-1, SBIT-3	7.171	(on-peak)
	4.992	(off-peak)

Q. How does Tampa Electric's proposed average fuel adjustment factor of 5.897 cents per kWh compare to the average fuel adjustment factor for the January 2006 through December 2006 period?

A. The proposed fuel charge factor is 0.484 cents per kWh (or $4.84 per 1,000 kWh) higher than the average fuel charge factor of 5.413 cents per kWh for the January 2006 through December 2006 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2007 fuel and purchased power and capacity cost recovery projections?

A. Yes. There are three significant events. These are 1) the significant changes in natural gas prices that resulted from Hurricane Katrina; 2) the company's wholesale purchases; and 3) Tampa Electric's recovery of waterborne coal transportation costs as required in Order No. PSC-04-0999-FOF-EI ("Order No. 04-0999") issued October 12, 2004 in Docket No. 031033-EI.

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

A. With the addition of the natural gas-fired Bayside Station in 2004, Tampa Electric has increased its reliance on natural gas as a fuel source. In 2005, Hurricane Katrina affected the region where much of the nation's natural gas supply originates, resulting in reduced production and delivery constraints that caused a spike in the price of natural gas. The spike in natural gas prices over the last quarter of 2005 resulted in an average natural gas price per MMBTU that was 60% higher than the price in the 2006 projection filed in October 2005. Witness J. T. Wehle's direct testimony describes the increase in natural gas costs in more detail. The post-hurricane effects of Hurricane Katrina on natural gas prices are a key driver behind Tampa Electric's increased fuel costs.

Q. Please describe the second event.

A. Tampa Electric entered into or continued several cost effective purchase agreements with Progress Energy Florida, Cargill and Calpine Energy Services, L.P. The purchases improve supply reliability for retail ratepayers in 2006 and 2007 at reasonable and prudent costs. The direct testimony of Tampa Electric witness B. F. Smith describes the purchases and demonstrates that the costs associated with the purchased power agreements are prudent and appropriate for recovery through the Fuel and Purchased Power and Capacity Cost Recovery Clauses.

Tampa Electric also intends to enter into purchase agreements to replace lost generation capacity during the planned Big Bend scrubber outages beginning in 2007.

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

A. The calculation of the 2007 fuel and purchased power factor reflects Tampa Electric's recovery of waterborne coal transportation costs as required in Order No. PSC-04-0999-FOF-EI ("Order No. 04-0999") issued October 12, 2004 in Docket No. 031033-EI. Tampa Electric adjusted fuel expense for the disallowance of costs required by FPSC Order No. 04-0999, which specifies that a portion of the costs incurred by Tampa Electric under the current contract with TECO Transport is not reasonable for cost recovery. The annual adjustment to the company's fuel cost recovery is projected to be $15,315,380 in 2007. This adjustment will be trued up to reflect the actual tons shipped and associated calculated disallowances as part of the normal true-up process.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2007?

A. The company's projected 2007 benchmark is ~~$1,165,220~~ $946,443, which is the three-year average of ~~$1,049,937,~~ $783,202, ~~$878,238~~ $711,660 and ~~$1,567,484~~ $1,344,467 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2004, 2005 and 2006 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2007 from non-separated wholesale sales to exceed its 2007 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark of $1,165,220.

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 $4.93 beginning January 2007. These charges are shown in Exhibit CA-3, Document No. 2, on Schedule E10.

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 2007.

Q. Does this conclude your testimony?

A. Yes, it does.

MR. BEASLEY: We tender Mr. Aldazabal for questions regarding gas storage costs.

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning, Mr. Aldazabal.

A Good morning.

Q I think I got it close.

TECO's last rate case was 19 -- had a 1994 test year, and that was in Docket 920324-EI, with the final order issued May 19th, 1993; is that correct?

A Subject to check, yes. Sounds right.

Q And is it correct that TECO obtained natural gas storage since Hurricane Ivan in 2004?

A That's my understanding. Yes.

Q Okay. And would you agree, subject to check, that the issuance date of the hedging order, that would be PSC-021484-S-EI, was October 30th, 2002?

A That's correct.

Q Okay. And would it also be correct that TECO has not recovered any carrying costs on the inventory balance in its natural gas storage through the fuel clause?

A We have not recovered the carrying costs. That's correct.

Q Okay. And is it correct that TECO is earning within its authorized rate on equity, and that's 10.75 percent to

12.75 percent?

A That's correct.

Q And as of August 2006, TECO's ROE was 11.12 percent based on the FPSC adjusted basis for August 2006 surveillance report; is that correct?

A I don't have that surveillance report in front of me, but it sounds reasonable.

MS. CHRISTENSEN: Okay. I have no further questions.

MR. McWHIRTER: No questions from FIPUG.

CHAIRMAN EDGAR: Thank you.

CAPTAIN WILLIAMS: No questions.

CHAIRMAN EDGAR: No questions.

Questions from any other party on cross for this witness? None.

Staff? Commissioners?

Mr. Beasley.

MR. BEASLEY: Thank you. I'd ask that Mr. Aldazabal be excused.

CHAIRMAN EDGAR: You may be excused. Thank you, sir.

MR. BEASLEY: Our next witness is Mr. William A. Smotherman. And I would propose that we stipulate in his testimony regarding GPIF reward and penalty and have him appear later in connection with the dead band issue addressed in Mr. Ross's testimony. So I would propose that his prepared direct testimony filed September 1, 2006, his prepared direct testimony filed April 3, 2006, addressing actual generating unit performance be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony as described will be entered into the record as though read.

MR. BEASLEY: And that would also include moving into the record what's marked as Exhibit 47 in the staff's comprehensive exhibit list, as well as 48.

CHAIRMAN EDGAR: Exhibits 47 and 48 will be entered into the record.

MR. BEASLEY: And we will call him again later when his time comes.

CHAIRMAN EDGAR: And we will look forward to Mr. Smotherman later in the proceeding.

MR. BEASLEY: Thank you.

(Exhibits 47 and 48 marked for identification and admitted into the record.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM A. SMOTHERMAN

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

A. My name is William A. Smotherman. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of the Resource Planning Department.

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

A. I received a Bachelor of Electrical Engineering degree in 1986 from the University of South Florida. In May 1986, I joined Tampa Electric as an associate engineer, and I have worked in the areas of system planning, commercial/ industrial account management and wholesale power marketing. In February 2001, I was promoted to Director, Resource Planning. My present responsibilities include the areas of system reliability, generation expansion and system fuel and purchased power forecasting and related economic analyses.

Q. What is the purpose of your testimony?

A. My testimony presents Tampa Electric's actual performance results from unit equivalent availability and station heat rate used to determine the GPIF for the period January 2005 through December 2005. I will also compare these results to the targets established prior to the beginning of the period.

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

A. Yes, Exhibit No. _____ (WAS-1), consisting of two documents, was prepared under my direction and supervision. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2005 - December 2005, True-up" is consistent with the GPIF Implementation Manual previously approved by the Commission. In addition, Document No. 2 provides the company's Actual Unit Performance Data for the 2005 period.

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

A. Five of the company's units are included. They are Big Bend Station Units 1, 2, 3, and 4 and Polk Station Unit 1.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2005 through December 2005 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 26. Based upon -0.182 GPIF points, the result is a penalty amount of $99,791 for the period.

Q. Please proceed with your review of the actual results for the January 2005 through December 2005 period.

A. On Document No. 1, page 3 of 26, the actual average common equity for the period is shown on line 14 as $1,394,720,154. This produces the maximum penalty or reward amount of $5,479,030 as shown on line 21.

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

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

Q. Are the equivalent availability results shown on Document No. 1, page 6 of 26, column 2, directly applicable to the GPIF table?

A. No. Adjustments to equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 26. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 1

On this unit, 1344.0 planned outage hours were originally scheduled for 2005. Actual outage activities required

754.6 planned outage hours. Consequently, the actual equivalent availability of 61.0% is adjusted to 56.6% as shown on Document No. 1, page 7 of 26.

Big Bend Unit No. 2

On this unit, 336.0 planned outage hours were originally scheduled for 2005. Actual outage activities required 1399.5 planned outage hours. Consequently, the actual equivalent availability of 64.8% is adjusted to 74.2% as shown on Document No. 1, page 8 of 26.

Big Bend Unit No. 3

On this unit, 336.0 planned outage hours were originally scheduled for 2005. Actual outage activities required 617.9 planned outage hours. Consequently, the actual equivalent availability of 51.5% is adjusted to 53.4% as shown on Document No. 1, page 9 of 26.

Big Bend Unit No. 4

On this unit, 336.0 planned outage hours were originally scheduled for 2005. Actual outage activities required 683.8 planned outage hours. Consequently, the actual equivalent availability of 70.7% is adjusted to 73.8% as shown on Document No. 1, page 10 of 26.

Polk Unit No. 1

On this unit, 330.5 planned outage hours were originally scheduled for 2005. Actual outage activities required 0 planned outage hours. Consequently, the actual equivalent availability of 68.5% is adjusted to 65.9%, as shown on Document No. 1, page 11 of 26.

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

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 26, column 4. This number is entered into the respective Generating Performance Incentive Point ("GPIP") table for each particular unit on pages 20 of 26 through 24 of 26. Page 4 of 26 summarizes the equivalent availability points to be awarded or penalized.

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

A. The actual heat rate and adjusted actual heat rate for Big Bend Units 1, 2, 3, and 4 and Polk Unit 1 are shown on Document No. 1, page 6 of 26. The adjustment was developed based on the guidelines of section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J.H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 26. The heat rate value is entered into the respective GPIP table for the particular unit, shown on pages 20 of 26 through 24 of 26. Page 4 of 26 summarizes the weighted heat rate and equivalent availability points to be awarded.

Q. What is the overall GPIP for Tampa Electric for the January 2005 through December 2005 period?

A. This is shown on Document No. 1, page 26 of 26. Essentially, the weighting factors shown on page 4 of 26, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 26, column 4, are substituted within the equation. The resulting value, -0.182, is then entered into the GPIF table on page 2 of 26. Using linear interpolation, the penalty amount is $99,791.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 060001-EI
FILED: 9/1/06

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM A. SMOTHERMAN

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

A. My name is William A. Smotherman. My mailing and business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of the Resource Planning Department.

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

A. I received a Bachelor of Electrical Engineering degree in 1986 from the University of South Florida. In May 1986, I joined Tampa Electric as an associate engineer, and I have worked in the areas of system planning, commercial/ industrial account management and wholesale power marketing. In February 2001, I was promoted to Director, Resource Planning. My present responsibilities include the areas of system reliability, generation expansion and system fuel and purchased power forecasting and related economic analyses.

Q. What is the purpose of your testimony?

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

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

A. Yes, Exhibit WAS-Z ~~WAS-1~~, consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2007 period.

GPIF Calculations

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

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

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

GPIF methodology?

A. Yes, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission, with the exception of the criterion that the company shall include generating units that will represent at least 80 percent of projected system net generation.

Q. Please explain why does Tampa Electric does not include units that represent 80 percent of projected system net generation?

A. Due to the repowering of Gannon unit 6 to H. L. Culbreath Bayside ("Bayside") unit 2, the remaining GPIF units do not represent 80 percent of projected system net generation. Although Bayside unit 2 began commercial operation in 2004 the repowered unit is not included in the GPIF calculations because the company does not have the historical operational data required by the GPIF Implementation Manual to set GPIF targets. In addition, Tampa Electric has no other base load generating unit to substitute for Gannon unit 6. Section 3.2 of the GPIF Implementation Manual states that the Commission will approve exclusion of units from the calculation of the GPIF on a case-by-case basis, and the Commission previously approved this exception for Tampa Electric's projected GPIF filings. Therefore, Tampa Electric requests approval of its

2007 GPIF calculation excluding the repowered Bayside unit 2.

Q. Has Tampa Electric modified its GPIF methodology to account for the concerns expressed in Staff's testimony in the 2006 fuel hearing?

A. Yes. As requested by the Commission, Tampa Electric has worked with the Commission Staff and other interested parties to reach a mutually agreeable alternative proposal.

Q. Please describe the change in methodology.

A. Tampa Electric Company has agreed to remove the outage hours related to any forced outage that is identified as an outlier. The process of identifying outlying outages includes reviewing three years of historical performance and determining the average length (mean) and variation (standard deviation) of all forced outages. If a forced outage within the current sample period (July 2005 through June 2006) is greater than two standard deviations above the three year average outage duration (mean) its associated hours are removed from the GPIF calculations.

Q. As a result of the methodology change, were any outages identified as outliers?

A. Yes. An outage on Big Bend unit 3 was identified as an outlying outage; therefore, its associated forced outage hours were removed from the study.

Q. How will the methodology impact the true-up process?

A. The agreed upon methodology will not impact the true-up process, since no adjustments will be made to exclude outliers.

Q. Is this methodology consistent with the GPIF Implementation Plan?

A. Yes. Section 3.3 of the GPIF Implementation Manual allows for removal of outliers in the calculation.

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

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2007 period. A range of potential improvements and degradations were determined for each of these parameters.

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

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

To give an example for the 2007 period, the projected Equivalent Unplanned Outage Factor for Big Bend unit 2 is 17.74 percent, and the Planned Outage Factor is 5.75 percent. Therefore, the target equivalent availability factor for Big Bend unit 2 equals 76.51 percent or:

$$100\% - [(17.74 + 5.75\%)] = 76.51\%$$

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

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

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

$$EAF_{MAX} = 100\% - [0.8\ (EUOF_T) + 0.95\ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in Equivalent Forced Outage Factor or EUOF and Equivalent Maintenance Outage Factor or EMOF, plus a five percent reduction in the Planned Outage Factor are necessary. Continuing with the Big Bend unit 2 example:

$$EAF_{MAX} = 100\% - [0.8\ (17.74\%) + 0.95\ (5.75\%)] = 80.34\%$$

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

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

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

$$EAF_{MIN} = 100\% - [1.4\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing with the Big Bend unit 2 example,

$EAF_{MIN} = 100\% - [1.4 \ (17.74\%) + 1.10 \ (5.75\%)] = 68.83\%$

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

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

A. The company's planned outages for January through December 2007 are shown on page 19 of Document No. 1. Three GPIF units have a major outage (28 days or greater) in 2007; therefore, three Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Big Bend unit 4 is scheduled for a planned outage from February 1, 2007 to April 30, 2007. There are 2,136 planned outage hours scheduled for the 2006 period, and a total of 8,760 hours during this 12-month period. Consequently, the Planned Outage Factor for Big Bend unit 4 is 24.38 percent or:

$$\frac{2,136}{8,760} \times 100 = 24.38\%$$

The factor for each unit is shown on pages 5 and 13 through 18 of Document No. 1. Big Bend unit 1 has a Planned Outage Factor of 3.84 percent. Big Bend unit 2 has a Planned Outage

Factor of 5.75 percent. Big Bend 3 has a Planned Outage Factor of 8.49 percent. Polk unit 1 has a Planned Outage Factor of 3.29 percent and Bayside unit 1 has a Planned Outage Factor of 9.59 percent.

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

A. Graphs for both factors, adjusted for planned outages, versus time were prepared. Monthly data and 12-month rolling average data were recorded. For each unit the most current 12-month ending value, June 2006, was used as a basis for the projection. All projected factors are based upon historical unit performance unless adjusted for outlying forced outages. These target factors are additive and result in an Equivalent Unplanned Outage Factor of 16.12 percent for Big Bend unit 4. The Equivalent Unplanned Outage Factor for Big Bend unit 4 is verified by the data shown on page 16, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{\text{Period Hours}} \times 100$$

Or

$$EUOF = \frac{(1{,}129 + 284)}{8{,}760} \times 100 = 16.12\%$$

Relative to Big Bend unit 4, the EUOF of 16.12 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 35.47 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability for this unit is 60.69 percent.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 17.74 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 5.75 percent. Therefore, the target equivalent availability for this unit is 76.51 percent.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 34.15 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 8.49 percent.

Therefore, the target equivalent availability for this unit is 57.36 percent.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 16.12 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 24.38 percent. Therefore, the target equivalent availability for this unit is 59.50 percent.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 8.36 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 3.29 percent. Therefore, the target equivalent availability for this unit is 88.35 percent.

Bayside Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 9.39 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 9.59 percent. Therefore, the target equivalent availability for this unit is 81.02 percent.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 64.3 percent is shown on Page 5 of Document No. 1. This target is similar to the July 2005 through June 2006 GPIF period. Contributing to the system EAF are the planned outages at Big Bend unit 4 to install SCR equipment.

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

A. The adjustment makes the factors more accurate and comparable. Obviously, a unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. Since the units in the GPIF are usually base load units, reserve shutdown is generally not a factor.

To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend unit 4 on page 16 of Document No. 1. During the months of January and May through December, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the months of February through April, the Equivalent Unplanned Outage Rate exceeds Equivalent Unplanned Outage Factor due to the scheduling of a planned outage. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

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

$$FOF + MOF + POF + EAF = 100\%$$

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

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

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

Q. How were these targets determined?

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

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

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 29 through 34 of Document No. 1.

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

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

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2007 period.

A. The heat rate target for Big Bend unit 1 is 10,971 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±497 Btu/Net kWh. The heat rate target for Big Bend unit 2 is 10,484 Btu/Net kWh with a range of ±361 Btu/Net kWh. The heat rate target for Big Bend unit 3 is 11,090 Btu/Net kWh, with a range of ±908 Btu/Net kWh. The heat rate target for Big Bend unit 4 is 10,828 Btu/Net kWh with a range of ±651 Btu/Net kWh. The heat rate target for Polk unit 1 is 10,428 Btu/Net kWh with a range of ±1,011 Btu/Net kWh. The heat rate target for Bayside unit 1 is 7,378 Btu/Net kWh with a range of ±277 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 12 of Document No. 1.

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

A. Yes.

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

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 12. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $1,079,796.6 is shown on page 6, column 2.

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

After all of the individual savings are calculated, column 4 totals $58,301,700 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each parameter is then calculated by dividing individual savings by the total. For Big Bend unit 1, the weighting factor for equivalent availability is 12.26 percent as shown in the right-hand column on page 6. Pages 7 through 12 of Document No. 1 show the point table, the Fuel Savings /(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend unit 2, page 8, if the unit operates at 80.3 percent equivalent availability, fuel savings would equal $4,148,500 and ten equivalent availability points would be awarded.

The GPIF Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 12. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $58,301,700. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2007 is

$1,473,616,457. This produces the maximum allowed jurisdictional incentive of $5,829,646 shown on line 21.

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

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

Q. Please summarize your testimony on the GPIF.

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

$$
\begin{aligned}
\text{GPIP:} = (\ & 0.1226\ EAP_{BB1} + 0.0712\ EAP_{BB2} \\
& + 0.1713\ EAP_{BB3} + 0.1300\ EAP_{BB4} \\
& + 0.0559\ EAP_{PK1} + 0.0040\ EAP_{BAY1} \\
& + 0.0512\ HRP_{BB1} + 0.0408\ HRP_{BB2} \\
& + 0.0730\ HRP_{BB3} + 0.0627\ HRP_{BB4} \\
& + 0.0727\ HRP_{PK} + 0.1446\ HRP_{BAY1}\ )
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points.

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2007 period?

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

Q. Does this conclude your testimony?

A. Yes.

CHAIRMAN EDGAR: Captain Williams.

CAPTAIN WILLIAMS: We would call Witness Goins.

CHAIRMAN EDGAR: Witness Goins.

DENNIS GOINS

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

DIRECT EXAMINATION

BY CAPTAIN WILLIAMS:

Q Okay. Please state your name and business address for the record.

A My name is Dennis Goins. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q And were you previously in the hearing room when, when the other witnesses were sworn in?

A I was.

Q And what is your position and whom are you employed by?

A I'm self-employed doing business as Potomac Management Group. I have been since 1985.

Q Okay. And have you also filed testimony in this case dated 22, September, 2006?

A I have.

Q And were there also exhibits attached to that testimony?

A Yes, there were.

Q Okay. And are there any changes or corrections to your testimony?

A No, not at this time.

Q And if asked the same questions that you were asked in your testimony, would your responses be the same today?

A They would.

CAPTAIN WILLIAMS: We ask that the prefiled testimony be entered as if read.

CHAIRMAN EDGAR: The prefiled testimony will be entered into the record as if read.

CAPTAIN WILLIAMS: And we also ask that the attached exhibits which are designated as a DWG-1, DWG-2 and DWG-3 and identified in staff's exhibit list as 50 through 52 for ID also be similarly admitted.

CHAIRMAN EDGAR: Let's go ahead and hear the testimony, and then we'll enter the exhibits, if there's no objection, at the end of the testimony.

CAPTAIN WILLIAMS: Okay.

(Exhibits 50 through 52 marked for identification.)

STATE OF FLORIDA
BEFORE THE
PUBLIC SERVICE COMMISSION

RE: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR - FLORIDA POWER & LIGHT COMPANY	)))	Docket No. 060001-EI

DIRECT TESTIMONY OF DR. DENNIS W. GOINS ON BEHALF OF THE FEDERAL EXECUTIVE AGENCIES

INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. Following graduate school I worked as a staff economist at the North Carolina Utilities Commission. During my tenure at the Commission I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since leaving the Commission I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on pricing, market structure, planning, and policy issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and interutility planning, operations, and pricing; prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have participated in more than 100 proceedings before state and federal agencies as an expert in cost of service, rate design, utility restructuring, power market planning and operations, utility mergers, utility planning and operating practices, regulatory policy, management prudence, and competitive market issues. These agencies include the Federal Energy Regulatory Commission (FERC), the General Accounting Office (now the Government Accountability Office), the United States

Court of Federal Claims, the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, and regulatory agencies in Alabama. Arizona, Arkansas, Colorado, Florida, Georgia, Idaho, Illinois, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. Details of my professional qualifications are presented in Appendix A.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Federal Executive Agencies (FEA), which is comprised of all Federal facilities served by Florida Power & Light Company (FPL). Some of the largest FEA facilities include Patrick Air Force Base, Cape Canaveral Air Station, and the Kennedy Space Center.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review FPL's proposed 2007 Fuel Cost Recovery (FCR) factors and Capacity Cost Recovery (CCR) factors—including supporting data and information. In particular, I was asked to focus on how FPL develops CCR factors applicable to interruptible customers.

2. Identify any major deficiencies in FPL's proposed factors and suggest recommended changes.

Q. WHAT INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed FPL's application, testimony, and exhibits. I also reviewed documents and information found on web sites operated by the Commission and FPL.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following:

1. In general FPL has followed past practices in developing its proposed FCR and CCR factors—including factors for customers served under its Commercial/Industrial Load Control (CILC) Rate. Exceptions described by FPL's witnesses include a levelized bill methodology proposal[1] and recovery of costs associated with the Southeast Supply Header pipeline and the MoBay and BayGas storage projects.

2. CILC customers buy interruptible[2] (nonfirm) service—that is, they agree to curtail (through active load reductions) or displace (through on-site generation) at least 200 kW of load during peak periods when requested by FPL. In exchange for interrupting load when FPL decides such interruptions are necessary, CILC customers pay a discounted price for their nonfirm (that is, Load

[1] Under this proposed methodology, FPL attempts to mitigate the bill impacts of its new Generation Base Rate Adjustment (GBRA) for Turkey Point Unit 5.

[2] In my testimony I use *interruptible* and *curtailable* interchangeably in discussing nonfirm service.

Control) loads. This price discount reflects in part the cost of production capacity that FPL avoids by not having to add or buy capacity to serve interruptible load.

3. In developing CCR factors, FPL inappropriately assigned CILC customers responsibility for ***demand-related production costs*** associated with capacity purchases, even though they do not cause FPL to incur these costs. Because FPL classifies more than 90 percent of its nonfuel purchased capacity costs as demand-related costs, FPL's improper cost assignment results in grossly overstated CCR factors for CILC customers.

4. FPL also classifies part of its nonfuel purchased capacity costs as energy-related costs using the Commission-approved 12 CP and $1/13^{th}$ methodology, and recovers them through CCR factors. FPL's proposed CCR factors for CILC customers reflect a reasonable assignment of these costs to CILC customers.

5. FCR factors for CILC customers reflect in part their assigned responsibility for fuel costs associated with off-system purchases. FPL's treatment of CILC customers in developing these factors appears reasonable.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

1. Require FPL to exclude nonfirm (Load Control) demands in calculating the ***demand-related production cost component*** of Capacity Cost Recovery factors for CILC customers. Excluding such demands is necessary to avoid charging CILC customers for demand-related purchased capacity costs that they do not cause and for which they should not be responsible.
2. Adopt my recommended CCR factors, the development of which I describe in detail later in my testimony. The principal difference between these CCR factors and those proposed by FPL is that my recommended factors reflect no assignment to CILC customers of demand-related production costs associated with off-system purchases.

FPL'S PROPOSED FCR AND CCR FACTORS

Q. HOW DID FPL DEVELOP ITS PROPOSED FUEL COST AND CAPACITY COST RECOVERY FACTORS?

A. In general, FPL followed past practices in developing its proposed FCR and CCR factors. Instances in which FPL deviated from past practices—for example, its levelized bill methodology proposal[3] and recovery of costs associated with the Southeast Supply Header pipeline and the MoBay and BayGas storage projects—are described by FPL's witnesses.

[3] As I noted earlier, FPL proposes using this methodology to mitigate the bill impacts of its new GBRA for Turkey Point Unit 5.

Q. DID FPL USE THE SAME APPROACH TO DEVELOP FCR AND CCR FACTORS FOR INTERRUPTIBLE CUSTOMERS THAT IT USED IN PRIOR CASES?

A. Yes. With respect to its interruptible CILC program, FPL followed its traditional approach in developing FCR and CCR factors for customers served under Rate CILC-1.[4] For example, in developing FCR factors for CILC customers, FPL assigned these customers responsibility for not only a share of its on-system generation fuel costs, but also a share of fuel costs associated with off-system purchases. Similarly, in developing CCR factors, FPL classified part of its nonfuel purchased capacity costs as energy-related costs using the Commission-approved 12 CP and 1/13th methodology, and assigned a share of these costs to interruptible CILC customers. These costs assignments are reasonable.

Q. DO YOU AGREE WITH HOW FPL ASSIGNED OTHER COSTS IN DEVELOPING CCR FACTORS FOR CILC CUSTOMERS?

A. No. One element of FPL's traditional approach is problematic. More specifically, in developing CCR factors, FPL continued its past practice of assigning CILC customers responsibility for ***demand-related production costs*** associated with capacity purchases, even though CILC customers do not cause FPL to incur these costs. Because FPL classifies more than 90 percent of its nonfuel purchased capacity costs as demand-related costs,[5]

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[4] See FPL's September 1, 2006 filing in this docket, Appendixes III and IV. FPL's proposed FCR factors using its levelized bill methodology are shown in Appendix II.

[5] Demand-related production costs account for the bulk of FPL's nonfuel purchased capacity expense.

FPL's improper cost assignment results in grossly overstated CCR factors for CILC customers.

Q. WHY SHOULD DEMAND-RELATED PRODUCTION COSTS ASSOCIATED WITH FPL'S CAPACITY PURCHASES NOT BE ASSIGNED TO CILC CUSTOMERS?

A. The simple reason is FPL does not plan to install or buy firm capacity to serve interruptible load. By excluding interruptible load from its peak-load capacity requirements, FPL achieves capacity-cost savings by not having to build or purchase capacity to serve the interruptible load. The avoided capacity includes not only capacity required to serve the interruptible load, but also reserve capacity that would have been built or acquired to provide reliability if interruptible customers had chosen firm service. Capacity-cost savings attributable to interruptible load include avoided fixed costs—for example, capital costs (including return), insurance, interest, taxes, and fixed nonfuel operation and maintenance (O&M) expense—and avoided variable costs—for example, fuel and variable O&M expense.

Interruptible load enables FPL to maximize the value of its existing reserve capacity and to avoid installing and/or purchasing new capacity. The available supply of interruptible service depends on the relationship between available capacity and firm service demands. That is, if FPL's demands command all available generating capacity, the supply of interruptible service falls to zero. When firm demands are significantly less than available capacity, the supply of interruptible service is significantly greater.

Q. UNDER WHAT CONDITIONS CAN FPL INTERRUPT CILC CUSTOMERS?

A. Under Rate CILC, FPL can interrupt load when necessary to:

- Alleviate a power supply or transmission emergency condition or capacity shortage.
- Keep FPL from operating its generators above their continuous rated output.

Q. DO BASIC ECONOMIC PRINCIPLES SUPPORT EXCLUDING FIXED DEMAND-RELATED PRODUCTION COSTS FROM PRICES FOR INTERRUPTIBLE SERVICE?

A. Yes. Fundamental economic theory demonstrates that interruptible customers do not cause a utility to incur demand-related production and bulk transmission costs. For example, Professor James C. Bonbright, a recognized pricing authority, advocated pricing interruptible service to reflect no capacity-related cost of service:

> Interruptible service has been used by both gas and electric companies for peak shaving. The costs cannot be accurately determined because it is a byproduct resulting from generating and bulk transmission facilities built and operated for firm service (see Nissel, 1983). As a result, only the customer cost (e.g., customer-connected spur lines and substations) and energy costs (e.g., fuel and incremental maintenance cost) actually incurred and ***no capacity pricing cost should be included in pricing interruptible service***.

> While some feel that it is an impropriety to treat interruptible customers as if they were firm customers, they still opine that it would be fair and reasonable to obtain a small contribution from them for capacity costs. This is debatable.[6] (Emphasis added.)

Q. ARE INTERRUPTIBLE CUSTOMERS "FREE RIDERS" IF THEY PAY NO DEMAND-RELATED PRODUCTION COSTS?

A. No. As noted by Professor Bonbright, eliminating fixed capacity costs from interruptible prices might cause some to make the fallacious but politically attractive argument that interruptible customers are "free riders." However, an efficient pricing scheme requires customers to pay only for costs attributable to their demands. Since a utility does not build or acquire generating capacity to serve interruptible load, only firm service prices should include recovery of demand-related production costs.

Despite Professor Bonbright's pricing rule, most interruptible rates—including FPL's Rate CILC and associated CCR factors—recover a large portion of the utility's fixed costs of capacity built or acquired to serve only firm loads. This fact alone empirically demonstrates that interruptible customers are not "free riders."

Q. ARE ANY FEA CUSTOMERS SERVED UNDER RATE CILC?

A. Yes. At least one account for each of the major FEA customers I noted earlier is served at transmission voltage under Rate CILC-1T.[7]

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[6] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, Arlington, Virginia: Public Utilities Reports, Inc., 1988, page 502.

[7] FPL closed Rate CILC-1 to new customers in 2000.

Q. DO CILC CUSTOMERS PAY A LOWER PRICE FOR NONFIRM DEMAND THAN THEY PAY FOR THEIR FIRM DEMAND?

A. Yes. In exchange for agreeing to interrupt load when FPL decides such interruptions are necessary, CILC customers pay a discounted price for their nonfirm (that is, Load Control) loads.

Q. DOES RATE CILC'S DISCOUNTED NONFIRM DEMAND PRICE ALREADY COMPENSATE THEM FOR DEMAND-RELATED PURCHASED CAPACITY COSTS THAT FPL AVOIDS?

A. No. The implicit price discount for nonfirm demands in Rate CILC and the rate's CCR factors are determined in separate venues—the first in a general rate case and the second in FPL's annual fuel proceeding. Rate CILC's implicit price discount reflects only FPL's embedded demand-related production costs—not FPL's combined embedded production costs and purchased capacity costs. However, the basic premise underlying the development of the implicit CILC price discount should also apply to Rate CILC's CCR factors. That is, FPL does not build or buy firm capacity to serve interruptible load. CILC customers should not be charged either through base rates or purchased capacity CCR factors for demand-related production costs they do not cause.

Q. IF FPL EXCLUDED NONFIRM DEMANDS IN CALCULATING CCR FACTORS FOR RATE CILC, WOULD CILC CUSTOMERS GET AN ADDITIONAL PRICE DISCOUNT TO WHICH THEY ARE NOT ENTITLED?

A. No. CILC customers should not be charged for costs they do not cause.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED WHETHER LOAD CONTROL DEMANDS SHOULD BE USED TO CALCULATE CCR FACTORS FOR CILC CUSTOMERS?

A. Yes. In FPL's last fuel case (Docket No. 050001-EI), the Commission considered whether nonfirm demands should be included in calculating CCR factors for CILC customers. The Commission's final order in that case said in part:[8]

> ...If the demands of CILC customers were excluded in calculating the capacity cost recovery factors, these customers would receive an additional discount that we do not believe is justified. This additional discount of approximately $21.8 million for the 2006 projection period would then inappropriately be recovered from the remaining ratepayers. Accordingly, we find that it is appropriate to include the full demand responsibility of the CILC customers in determining the appropriate factors. This is consistent with the method that has been filed by FPL and we have approved in the past. ***No evidence was presented at the hearing that supports a change in this method. Based on the evidence in the record, the demands of the CILC customers shall continue to be included when calculating the appropriate capacity cost recovery factors.*** (Emphasis added.)

[8] Order No. PSC-05-1252-FOF-EI at 20.

Q. DOES YOUR TESTIMONY ADDRESS CONCERNS RAISED BY THE COMMISSION IN ITS FINAL ORDER?

A. Yes. As I stated earlier, Professor Bonbright agrees that interruptible prices should exclude capacity costs. CILC customers are currently charged for demand-related purchased capacity costs they do not cause FPL to incur. In calculating CCR factors, CILC nonfirm demands should be excluded to prevent CILC customers from being unfairly assigned demand-related production costs from FPL's off-system purchases.

ALTERNATIVE APPROACH

Q. HAVE YOU DEVELOPED CCR FACTORS THAT REFLECT YOUR RECOMMENDED TREATMENT OF CILC NONFIRM DEMANDS?

A. Yes. In developing these CCR factors, I used the same basic approach as FPL[9] except that I excluded nonfirm CILC demands in calculating each rate schedule's assigned share of ***demand-related production costs*** from FPL's off-system purchases. My approach used a simple 2-step calculation in which I first assigned the following costs to all classes (including CILC customers):

- Fixed purchased capacity costs classified as energy-related costs using the Commission-approved 12 CP and 1/13th methodology. I assigned these costs on the basis of each rate group's kWh use.

[9] See FPL's September 1, 2006 filing in this docket, Appendix III at 4-5.

- Plant security costs as requested by FPL.[10] I assigned these costs on the basis of each rate group's coincident peak demands.
- Transmission-related costs (including revenue credits) associated with off-system transactions. I also assigned these costs on the basis of each rate group's coincident peak demands.[11]

I treated all other nonfuel purchased capacity costs as demand-related production costs. I then assigned these costs to all rate groups except CILC customers using their coincident peak demands as allocation factors. (See Exhibits DWG-1 and DWG-2.)

Q. DID YOU COMPARE CCR FACTORS DEVELOPED USING YOUR RECOMMENDED APPROACH TO THOSE DEVELOPED UNDER FPL'S APPROACH?

A. Yes. As shown in Exhibit No. DWG-3, the CCR factor under my recommended approach for all CILC customers is $0.31 per kW versus $2.09 per kW for CILC-1D/G customers and $2.01 per kW for CILC-1T customers under FPL's approach.

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[10] See FPL's witness Korel M. Dubin, direct testimony at 22-24. I take no position regarding whether these costs should be recovered through the Capacity Cost Recovery Clause.

[11] While Professor Bonbright asserts that bulk transmission costs should be excluded from interruptible prices, I have assigned these transmission-related costs to CILC customers.

Q. DOES FPL OFFER INTERRUPTIBLE RATE OPTIONS OTHER THAN RATE CILC?

A. Yes. In addition to Rate CILC-1, FPL offers interruptible service to customers under several other rate (or rider) options—for example, the CS and CST rates and Rider CDR.

Q. ARE YOU RECOMMENDING SIMILAR CHANGES IN FPL'S PROPOSED CCR FACTORS APPLICABLE TO THESE OTHER NONFIRM RATE OPTIONS?

A. No. Unlike Rate CILC, FPL's filing does not identify relevant data (for example, kWh sales and kW demands) necessary to calculate revised CCR factors applicable to customers served under its CS and CST rates and CDR rider. As a result, at this time I am not recommending that CCR factors applicable to these options be calculated in the same manner as I have recommended for Rate CILC-1.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

BY CAPTAIN WILLIAMS:

Q Dr. Goins -- it is appropriate to call you Doctor; is that correct?

A That will be fine.

Q Okay. Could you please summarize your testimony.

A Yes. My testimony focuses on one aspect of Florida Power & Light's filing with respect to the development and application of the capacity cost recovery factors. Specifically my recommendation is that the nonfirm loads, CILC interruptible customers be excluded from the calculation of those CCR factors.

The basis for my recommendation is that FP&L neither builds nor acquires capacity to serve interruptible customers served under the CILC rate. And as a result, the cost efficient pricing mechanism that should be applicable to interruptible service would exclude demand-related production costs from prices set for the interruptible component of service.

Moreover, I think that my proposal is, is quite fair. It's been criticized by some as unfair. In my opinion, it is fair in particular because of the millions of dollars in costs that many of these, over two-thirds, of the loads served under the CILC rate is backed up by customer-owned generation.

Customers expended millions of dollars investing in generating plant to qualify for this rate, and to charge them for services which, the cost of which they do not cause in my opinion is unfair. Moreover, I believe that the bill impacts on other customers that would result from my proposal are both reasonable and equitable.

CAPTAIN WILLIAMS: Okay. We'll submit the witness for questions.

CHAIRMAN EDGAR: Questions on cross for this witness?

MR. ANDERSON: Yes, Madam Chairman.

CHAIRMAN EDGAR: You're recognized.

MR. ANDERSON: Thank you very much.

CROSS EXAMINATION

BY MR. ANDERSON:

Q Good morning, Dr. Goins.

A Good morning.

Q Can you hear me?

A Yes.

Q Very good. My name is Bryan Anderson. I'm an attorney representing the Florida Power & Light Company.

You've submitted testimony in this case concerning capacity cost recovery allocations to customers served on FPL's commercial and industrial load control tariff; is that right?

A That's correct.

Q You'll understand me if I refer to CILC as an abbreviation; right?

A Yes.

Q First off, a moment ago in your summary I think you referred to your proposal being consistent with the Commission's rules. Did you say that?

A Yes, I did.

Q You were intending to provide a summary of your testimony; is that right?

A Yes.

Q Would you please point out for us and the Commission the portion of your testimony that says your proposal is consistent with the Commission's rules? I don't see one.

A You're correct.

Q Thank you.

MR. ANDERSON: Chairman Edgar, we'd move to strike that portion of the statement of Dr. Goins.

CHAIRMAN EDGAR: Captain Williams.

CAPTAIN WILLIAMS: I think that the testimony that was elicited would abbreviate these proceedings. We will simply go back and redirect and ask these same questions. But if this board would like to strike those since they are not actually in his, his testimony, you can do so, and we will ask the question later.

MR. ANDERSON: We would object to that also because we don't intend to interrogate on that point. It's a portion -- it's new matter raised only in the summary of the witness's testimony. It's inappropriate. It should be stricken.

CHAIRMAN EDGAR: Ms. Helton?

MS. HELTON: Madam Chairman, the purpose of the summary of the prefiled testimony is to just give a brief summary of what it is that the customers -- the witness has prefiled before the Commission. Any information outside the scope of that is inappropriate. So I believe that FPL is correct that that can be stricken from the record. And if someone does open the door to asking questions of the witness about what he stated in his summary, then the FEA may ask those questions on redirect.

CHAIRMAN EDGAR: Thank you, Ms. Helton.

CAPTAIN WILLIAMS: Madam Chairman, if I may be heard just briefly.

CHAIRMAN EDGAR: Yes, Captain Williams, you may.

CAPTAIN WILLIAMS: As part of these proceedings, and there's all this anticipated testimony that we've provided and that have been submitted, and part of that which is, which the response was to is that we anticipate that FPL will also place Ms. Morley on the stand. And in her testimony this is addressed as part of being consistent. So instead of just bringing him back up here after she testifies or asking that he be brought back up here, he's simply answering her question that she has stated in her testimony, which we anticipate will be filed or admitted in these proceedings. If you would tell us the proper procedure for doing that and getting his response in without having to call this witness back and doing that, we'll be glad to do it. But we didn't want to waste this board's time.

CHAIRMAN EDGAR: Ms. Helton?

MS. HELTON: I don't have all the background perhaps that I should. Has Dr. Goins been deposed and that has come out in a deposition transcript?

CAPTAIN WILLIAMS: He is responding to something that Ms. Morley has said in her rebuttal testimony that we anticipate will be entered here today.

MS. HELTON: Unfortunately, Madam Chairman, we don't have a process set up where witnesses or intervenors can rebut the rebuttal testimony that has already been filed. The way we have it set up is someone sets out their direct case and then the company can respond in rebuttal.

Presumably what -- I'm not sure that there is a process by which the FEA can get to what he's trying to get to.

CHAIRMAN EDGAR: Okay. Then this is my ruling. The court reporter is instructed, when the record is prepared, to strike the comments of the witness as requested by FPL. And on the lunch break, Captain Williams, if you would get with our staff and let's see if there is another way under our rules to accommodate the request. And, if so, we will attempt to do so. But that's where it stands right now. Thank you.

MR. ANDERSON: May I proceed?

CHAIRMAN EDGAR: You may.

BY MR. ANDERSON:

Q Dr. Goins, your testimony seeks a $16 million increase to the $30 million in annual discounts already received by CILC customers, which discounts are funded by all of FPL's other customers. Isn't that right?

A No.

Q Was that a yes?

A That's a no.

Q What part of that do you disagree with, sir?

A My testimony does not seek an additional discount for the CILC customers. My testimony focuses on identifying a proper method in which to assign costs to the CILC customers for any costs that they may impose on FPL and its purchase of capacity on an off-system basis.

It is my contention that FP&L neither buys nor acquires capacity in any form in order to serve nonfirm load, in particular on a firm basis.

If that, in fact, is true, then assigning those costs to the CILC customers as a matter of fact is improper and an improper application of pricing principles, enunciated, for example, by Professor Bonbright in his treatise when he spoke about pricing interruptible service and excluding from that all capacity-related costs.

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

I, LINDA BOLES, CRR, 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 8th day of November, 2006.

Linda Boles
LINDA BOLES, CRR, RPR
FPSC Official Commission Reporter
(850) 413-6734

cross-examining the witness, that might help a little.

MR. ANDERSON: That would be fine.

CAPTAIN WILLIAMS: May we also add in that we have no knowledge of how this thing was prepared, who it's prepared by, if it's actually testimony. We have no testimony. It doesn't seem like it's going to be indicated or admitted into the record. To cross-examine Dr. Goins on this matter seems to be unfair to Dr. Goins and to FEA; to know the source of this document and to cross-examine the person who actually prepared this to find out if it's actually accurate.

MS. HELTON: And, Madam Chairman, if I could add that I also agree with the FEA about that.

CHAIRMAN EDGAR: Yes, take a few moments. And for planning purposes let me go ahead and ask how many of the parties will also have questions on cross for this witness?

Mr. Twomey.

MR. TWOMEY: Very briefly, however.

CHAIRMAN EDGAR: Okay. Okay. We're going to take an informal couple of minutes very brief recess. Please stay close.

(Recess taken.)

(Transcript continues in sequence with Volume 5.)

interruptions and what year they are is not going to help him remember something that he never had any knowledge of. There's no point to this line of questioning. We object. The witness has no personal knowledge and this goes beyond his testimony.

MR. ANDERSON: This is cross-examination subject to check, as is the Commission's practice.

CHAIRMAN EDGAR: Ms. Helton?

MS. HELTON: It sounds to me as if the FEA is suggesting that this line of questioning is outside the scope of the witness's testimony. And just as the witness cannot give a summary of something outside the scope of his testimony, I don't believe he can testify to something that's outside the scope of his testimony.

MR. ANDERSON: The purpose of their testimony is to talk about essentially being undercompensated for providing interruptions. I'm trying to lay out some information concerning how infrequently those interruptions are called and then move on to his own client's performance in relation to the discounts that they receive. It's all directly pertinent to the claim that his clients are undercompensated in relation to the interruption they provide.

CHAIRMAN EDGAR: Ms. Helton.

MS. HELTON: Can I have a minute to look at his testimony? I haven't seen that. And maybe if Mr. Anderson could direct me to the lines of testimony about which he is

A It says, "Force majeure equipment failure."

Q This document should be Load Management Customer Control 1985 to Present.

A Then we're looking at different documents.

Q Okay. Yeah. It's a different document.

(Pause.)

All right. Dr. Goins, I'm very sorry for having the wrong document before you.

Directing your attention to the document called Load Management Customer Control 1985 to Present, looking down to the bottom and just counting up four lines, January 25, 2003, cold weather extremes. Do you see that?

A Yes, I do.

Q And then in September and October 2004 there's a reference to the load management customer control interruptions for purposes of Hurricane Jeanne damage. Do you see those two?

A What was that date? I'm sorry.

Q September 27, 2004, and October 1, 2004.

A Yes.

Q And then August 30, 2005 --

CAPTAIN WILLIAMS: Ma'am, I'm going to object to this line of questioning. Dr. Goins has no knowledge about what interruptions there have been. I believe there was a question asked whether or not he knew the number of interruptions that there were and he indicated no. Going down this list of firm contract power and demand. The difference between those two multiplied by the nonfirm or load control load under CILC is approximately equal to $30 million.

Q CILC customers pay about $30 million per year less in aggregate in exchange for promising to interrupt when required; right?

A That's correct.

Q Isn't it true in the past five years CILC customers have only been asked to interrupt four times?

A That I can't say yes or no to.

MR. ANDERSON: Mr. Diaz, would you please distribute the document called Load Management Customer Control?

CHAIRMAN EDGAR: Mr. Anderson, do we need to mark it?

MR. ANDERSON: I'm sorry?

CHAIRMAN EDGAR: Do we need to identify?

MR. ANDERSON: I'm not going to offer it in evidence.

BY MR. ANDERSON:

Q Dr. Goins, have you had a chance to look at the document in front of you?

A Yes.

Q I'd just like to call your attention to the last four lines of the document and see if I have this right, if you'll accept this subject to check, that in 2003 CILC was implemented one time due to cold weather extremes. Do you see that? Fourth line from the bottom, January 25, 2003.

So I am not proposing, as you term it, an additional discount. I am simply saying that the proper method for setting the CCR factor for the CILC classes is as I have proposed in my testimony.

Q Let me try a different way. CILC customers are allocated about $19 million worth of demand-related costs; is that right?

A In what form?

Q Per your testimony. You're seeking a reduction in the allocation from about $19 million to $3 million of demand-related costs; is that right?

A That would be the result of my testimony as filed.

Q That would be the result of your testimony?

A Of a CCR factor.

Q Right. You're not proposing that that $16 million be disallowed at all, are you?

A No.

Q It would be shifted to nonCILC customers; isn't that right?

A That's correct.

Q You agree with me the rate CILC customers are presently provided is about $30 million in discounts?

A The difference -- I'm not sure how you define discounts. There is a stated demand charge for CILC nonfirm demand or load control demand. There's a stated price for CILC