BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060007-EI

In the Matter of

ENVIRONMENTAL COST RECOVERY CLAUSE.
_______________________________/

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VOLUME 2

Pages 206 through 306

PROCEEDINGS: HEARING

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

DATE: Monday, November 6, 2006

TIME: Commenced at 9:30 a.m.

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

REPORTED BY: JANE FAUROT, RPR
Official FPSC Reporter
(850) 413-6732

PARTICIPATING: (As heretofore noted.)

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BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

A. My name is Howard T. Bryant. 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, Rates in the Regulatory Affairs Department.

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

A. I graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position, I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

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

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goals setting and DSM plan approval dockets, and other ECCR dockets since 1993, and ECRC activities since 2001.

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

A. The purpose of my testimony is to present, for Commission review and approval, the actual true-up amount for the ECRC and the calculations associated with the environmental compliance activities for the January 2005 through December 2005 period.

Q. Did you prepare any exhibits in support of your testimony?

A. Yes. Exhibit No. _____ (HTB-1) consists of eight forms prepared under my direction and supervision. Form 42-1A, Document No. 1, presents the final true-up for the

January 2005 through December 2005 period; Form 42-2A, Document No. 2, provides the detailed calculation of the actual true-up for the period; Form 42-3A, Document No. 3, details the calculation of the interest provision for the period; Form 42-4A, Document No. 4, reflects the calculation of variances between actual and actual/estimated costs for O&M activities; Form 42-5A, Document No. 5, provides a summary of actual monthly O&M activity costs for the period; Form 42-6A, Document No. 6, provides details of the calculation of variances between actual and actual/estimated costs for capital investment projects; Form 42-7A, Document No. 7, presents a summary of actual monthly costs for capital investment projects for the period; Form 42-8A, Document No. 8, pages 1 through 23, consists of the calculation of depreciation expenses and return on capital investment for each project that is being recovered through the ECRC, and page 24 calculates the net expenses associated with maintaining an SO_2 allowance inventory.

Q. What is the source of the data presented by way of your testimony or exhibits in this process?

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

Q. What is the actual true-up amount Tampa Electric is requesting for the January 2005 through December 2005 period?

A. Tampa Electric has calculated and is requesting approval of an over-recovery of $77,452,269 as the actual true-up amount for the January 2005 through December 2005 period.

Q. What is the adjusted net true-up amount Tampa Electric is requesting for the January 2005 through December 2005 period which is to be applied in the calculation of the environmental cost recovery factors to be refunded/(recovered) in the 2007 projection period?

A. Tampa Electric has calculated and is requesting approval of an under-recovery of $23,609,173 reflected on Form 42-1A, as the adjusted net true-up amount for the January 2005 through December 2005 period. This adjusted net true-up amount is the difference between the actual over-recovery and the actual/estimated over-recovery for the

January 2005 through December 2005 period as depicted on Form 42-1A. The actual true-up amount for the January 2005 through December 2005 period is an over-recovery of $77,452,269 as compared to the $101,061,442 actual/estimated over-recovery amount approved in FPSC Order No. PSC-05-1251-FOF-EI issued December 22, 2005.

Q. Are all costs listed in Forms 42-4A through 42-8A attributable to environmental compliance projects approved by the Commission?

A. All costs listed in Forms 42-4A through 42-8A for which Tampa Electric is seeking recovery are attributable to environmental compliance projects approved by the Commission. However, Form 42-8A, pages 20 - 23, provides expenditures associated with Big Bend Units 1 - 4 Selective Catalytic Reduction ("SCR") projects and are only included at this time for identification and tracking purposes. Recovery of these expenditures is not included in the 2005 ECRC True-Up. Consistent with the Commission's decisions in Docket Nos. 980693-EI, 040007-EI, 040750-EI and 041376-EI, the company will not seek recovery of the SCR project costs associated with these environmental compliance projects until each project is both approved and placed in-service. Big Bend Unit 4 SCR was approved in Docket No. 040750-EI, Order No. PSC-04-0986-PAA-EI and is projected to be in-service June 2007. Big Bend Units 1-3 SCRs were approved in Docket No. 041376-EI, Order No. PSC-05-0502-PAA-EI and are projected to be in-service May 2008, May 2009 and May 2010, respectively.

Q. Please explain the two adjustments of $11,089 and $78,494 contained on Form 42-2A, line 10.

A. The adjustment for $11,089 represents SO_2 allowance revenue from economy sales made from Tampa Electric's generating system during 2004. This revenue is an offset to SO_2 allowance costs collected through the ECRC; however, the company discovered the inadvertent omission of this revenue subsequent to filing the 2004 ECRC true-up. With this adjustment and its associated interest, customers have been made whole.

During the 2005 Commission audit of Tampa Electric's 2004 ECRC true-up, it was determined that the company had not updated depreciation rates for certain capital projects to be consistent with the rates approved in Docket No. 030409-EI, Order No. PSC-04-0815-PAA-EI, issued August 20, 2004. The adjustment for $78,494 represents an over-recovery of depreciation expense with associated interest resulting from the revised depreciation rates being applied to the appropriate projects for 2004.

Q. Is Tampa Electric including costs in this ECRC true-up filing for any environmental projects that were not anticipated and included in its 2005 factors?

A. Yes. On November 10, 2004, Tampa Electric filed a petition for approval of cost recovery for the Clean Water Act Section 316(b) Phase II Study project. In Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005, the Commission granted cost recovery approval for prudent costs associated with the project. This project was identified in the actual/estimated projection filing and was included in the 2006 projection filing.

In addition, On September 29, 2005, Tampa Electric filed a petition for approval of cost recovery for the Arsenic Ground Water Standard Program project. In Docket No. 050683-EI Order No. PSC-06-0138-PAA-EI, issued February 23, 2006, the Commission granted cost recovery approval for prudent costs associated with the project.

The actual 2005 costs for both projects are included in this ECRC true-up filing.

Q. How did actual expenditures for the January 2005 through December 2005 period compare with Tampa Electric's actual/estimated projections as presented in previous testimony and exhibits?

A. As shown on Form 42-4A, total O&M activities costs were $23,254,673 or 25.0 percent greater than actual/estimated projections. Form 42-6A shows the total capital investment costs were $23,213 or 0.1 percent lower than actual/estimated projections. O&M and capital investment projects with material variances from the 2005 Actual/Estimated True-Up filing are explained below.

<u>O&M Project Variances</u>

- **Big Bend Unit 3 Flue Gas Desulfurization Integration:** The Big Bend Unit 3 Flue Gas Desulfurization Integration project variance was $177,745 or 7.0 percent greater than projected due to an increase in consumables, principally limestone and maintenance stemming from greater unit output than originally projected.
- **SO_2 Emissions Allowances:** The SO_2 Emission Allowances project variance was $22,912,238 or 22.4 percent greater

than projected. The variance is due to the delayed sale of a small portion of SO_2 allowances originally projected to occur in late 2005 that actually transpired in early 2006.

- **Bend Unit 1 & 2 Flue Gas Desulfurization:** The Big Bend Units 1 & 2 Flue Gas Desulfurization project variance was $544,573 or 11.0 percent greater than projected. This variance is due to an increase in consumables from a higher unit output than originally projected.
- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance was $45,427 or 11.6 percent lower than projected due to continuous emissions monitoring activity that was delayed until 2006. Also, contracted labor for maintenance was reduced for the year through the utilization of internal labor resources not recovered through the clause.
- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance was $84,683 or 14.8 percent lower than projected due to less than anticipated maintenance and testing activities.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance was $243,366 or 55.7 percent lower than projected. The variance was due to an unusually wet seasonal condition which limited dry season sampling. Dry sampling is expected to continue in early

2006.

- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance was $3,736 or 11.3 percent lower than projected. The variance was due to lower than anticipated maintenance as well as lower than expected saturator expense as a result of a combustion turbine outage.
- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance was $5,842 or 97.4 percent lower than projected due to the newness of the equipment and it requiring less maintenance than originally anticipated.
- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study was $15,456 or 5.0 percent less than projected due to lower than anticipated project costs and timing of invoices.
- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program was $21,752 greater than projected due to the project not being filed at the time of the submission of the 2005 actual/estimated true-up filing. The Petition seeking cost recovery for this project was filed with the Florida Public Service Commission on September 29, 2005.

Capital Investment Project Variances

- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance was $12,096 or 18.9 percent less than projected due to lower than anticipated installation costs.
- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance was $483 or 79.8 percent higher than projected due to the early payment of invoices in 2005 that were originally projected to be paid in 2006.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

A. My name is Howard T. Bryant. 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, Rates in the Regulatory Affairs Department.

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

A. I graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

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

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goals setting and DSM plan approval dockets, and other ECCR dockets since 1993, and ECRC activities since 2001.

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

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2006 through December 2006 estimated true-up amount to be refunded or recovered through the ECRC during January 2007 through December 2007. My testimony addresses the recovery of capital and operating and maintenance ("O&M") costs associated with environmental compliance activities for 2006, based on six months of actual data and six months of estimated data. This information will be used to determine the environmental cost recovery factors for January 2007 through December 2007.

Q. Have you prepared an exhibit that shows the determination of the recoverable environmental costs for the period January 2006 through December 2006?

A. Yes. Exhibit No. ______ (HTB-2), containing one document, was prepared under my direction and supervision. It includes Forms 42-1E through 42-8E which show the current period estimated true-up amount to be used in calculating the cost recovery factors for January 2007 through December 2007.

Q. Please explain the one time adjustment of $41,743 contained on Form 42-2E, line 10.

A. The adjustment of $41,743, including interest, represents an inadvertent error that occurred when calculating the actual O&M expense for the Big Bend Units 1 and 2 Flue Gas Desulfurization project. The error was discovered and corrected during the 2006 Commission audit of Tampa Electric's 2005 ECRC true-up. With this adjustment, Tampa Electric customers have been made whole.

Q. What has Tampa Electric calculated as the estimated true-up for the current period to be applied to the January 2007 through December 2007 ECRC factors?

A. The estimated true-up applicable for the current period, January 2006 through December 2006, is an over-recovery of $58,359,404. A detailed calculation supporting the estimated true-up is shown on Forms 42-1E through 42-8E of my exhibit.

Q. Is Tampa Electric including costs in this estimated true-up filing for any environmental projects that were not anticipated and included in its 2006 factors?

A. Yes. On September 29, 2005, Tampa Electric filed a petition for approval of cost recovery of the Arsenic Groundwater Standard Program which is required by the Environmental Protection Agency and the Department of Environmental Protection. Effective January 1, 2005 regulated entities of the State of Florida are required to monitor the drinking water and groundwater Maximum Contaminant Level for arsenic under the federal rule known as the Safe Drinking Water Act.

In Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2006, the Commission granted Tampa Electric cost recovery approval for prudent costs associated with this project. The new standard applies to Tampa Electric's H.L. Culbreath Bayside, Big Bend and

Polk Power Stations.

Additionally, Tampa Electric filed a petition on December 27, 2005, for approval of cost recovery for the Big Bend Flue Gas Desulfurization ("FGD") Reliability project. This project is necessary to reliably maintain FGD system operations after the 2009 and 2012 Big Bend Station deadlines required by the Consent Decree.

In Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006, the Commission granted cost recovery approval for prudent costs associated with this project. The FGD reliability project will run concurrently with the installation of selective catalytic reduction ("SCR") systems on the generating units.

On the July 21, 2006 the Office of Public Counsel ("OPC") filed a protest to the aforementioned Commission order. Pending the outcome of the protest, the company will proceed with the inclusion of the prudently incurred FGD costs in the ECRC and respond accordingly to OPC's protest.

The anticipated 2006 costs associated with both of these projects are included in this estimated ECRC true-up filing.

Q. How did the actual/estimated project expenditures for January 2006 through December 2006 period compare with the company's original projection?

A. As shown on Form 42-4E, total O&M activities were $55,861,207 lower than projected costs. Total capital expenditures itemized on Form 42-6E, were $10,175 greater than originally projected. O&M and capital investment projects with material variances are explained below.

O&M Project Variances

- **Big Bend Unit 3 Flue Gas Desulfurization Integration:** The Big Bend Unit 3 Flue Gas Desulfurization Integration project variance is estimated to be $1,553,858 or 60.1 percent greater than originally projected due to an increase in the use of consumables, principally limestone and chemicals, stemming from greater unit output. Additionally, structural steal repairs were necessary on the absorber feed tank as well as two towers.
- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is estimated to be $57,586,724 less than originally projected. The variance is due to the sale of SO_2 allowances originally projected to occur in late 2005

that actually transpired in early 2006. Additionally, Tampa Electric plans to take advantage of forecasted favorable pricing in the SO_2 allowance market and thereby pass the revenue from the allowance sales directly to customers as an offset to the otherwise projected allowance expenses for 2006.

- **Big Bend Units 1 and 2 Flue Gas Desulfurization:** The Big Bend Unit 1 and 2 Flue Gas Desulfurization project variance is estimated to be $734,996 or 14.3 percent greater than originally projected due to an increase in the use of consumables, principally limestone and chemicals, stemming from greater unit output.
- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance is estimated to be $474,990 or 59.4 percent less than originally projected due to the continuous emissions monitoring activity that will be delayed until 2007. Also, the project required less maintenance than originally anticipated.
- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance is estimated to be $150,647 or 21.5 percent greater than originally projected due to unanticipated inspections on boiler tubes and burner modifications.
- **Gannon Thermal Discharge Study:** The Gannon Thermal

Discharge Study project variance is estimated to be $35,123 or 70.2 percent higher than originally projected. The variance is due to unusually wet conditions in 2005, which limited dry season sampling. For that reason, the dry season sampling was completed in early 2006.

- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance is estimated to be $16,100 or 67.1 percent greater than originally projected due to a greater amount of maintenance to the saturator than anticipated.
- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance is estimated to be $63,362 or 84.5 percent lower than originally projected due to less maintenance activity than anticipated.
- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is estimated to be $50,000 or 100 percent less than originally projected due to the delay of the in-service date for the capital project.
- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR project variance is estimated to be $75,000 or 100 percent less than originally projected due to the delay of the in-service date for the capital project.
- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is estimated to be $25,000 or 100 percent less than originally projected due to the delay

of the in-service date for the capital project.

- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study project variance is estimated to be $82,094 or 10.8 percent less than projected. The variance is due to the sampling of the impingement survival study occurring at a slower rate than originally projected. The sampling activity is anticipated to resume the normal schedule for 2007.
- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program variance is estimated to be $5,595 due to the project not being filed at the time of the submission of the 2006 projection filing.

<u>Capital Investment Project Variances</u>

- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is estimated to be $11,935 or 7.8 percent greater than the original projection due to higher than anticipated windbox material costs and neural network tuning expenses, which will occur during the fall 2006 maintenance outage.
- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is estimated to be $13,686 or 16.4 percent less than the original projection due to the early payment of invoices in 2005 that were originally projected to be paid in the spring of 2006.

- **Big Bend FGD Reliability:** The Big Bend FGD Reliability project variance is estimated to be $39,435 due to the project not being filed at the time of the submission of the 2006 projection filing.
- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is estimated to be $8,417 or 8.4 percent less than originally projected. The variance is due to the sale of a portion of SO_2 allowances originally projected to occur in late 2005 that actually transpired in early 2006 as well as the projected sale of allowances during the balance of 2006.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 060007-EI
FILED: SEPTEMBER 1, 2006

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

A. My name is Howard T. Bryant. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Rates in the Regulatory Affairs Department.

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

A. I graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

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

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goals setting and DSM plan approval dockets, and other ECCR dockets since 1993, and ECRC activities since 2001.

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

A. The purpose of my testimony is to present, for Commission review and approval, both the calculation of the revenue requirements and the projected ECRC factors for the period of January 2007 through December 2007. In support of the projected ECRC factors, my testimony identifies the capital and operating and maintenance ("O&M") costs associated with environmental compliance activities for the year 2007.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2007 through December 2007?

A. Yes. Exhibit No. ___ (HTB-3), containing one document, was prepared under my direction and supervision. It includes Forms 42-1P through 42-7P which show the calculation and summary of O&M and capital expenditures that support the development of the environmental cost recovery factors for 2007.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2007 through December 2007?

A. The net true-up applicable for this period is an over-recovery of $34,738,235. This consists of the final true-up under-recovery of $23,609,173 for the period of January 2005 through December 2005 and an estimated true-up over-recovery of $58,347,408 for the current period of January 2006 through December 2006. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-8E of Exhibit No. ___ (HTB-2) filed with the Commission on August 4, 2006 with revisions to Forms 42-1E, 42-2E, 42-3E, 42-6E, 42-7E and 42-8E filed with the Commission on August 16, 2006.

Q. What is the major contributing factor that has created the significant net over-recovery to be applied to the company's ECRC rates for the period January 2007 through December 2007?

A. The major contributing factor that has created the significant net over-recovery is the sale of approximately $56 million worth of surplus SO_2 emission allowances during 2006.

Subsequent to the repowering project at Bayside Power Station, Tampa Electric conducted a thorough evaluation of its SO_2 emission allowance needs for a 20-year horizon. The evaluation indicated two key facts: 1) the company would have a significant surplus of allowances, and 2) the allowance needs for the company's generation fleet would be adequately covered by the remaining allowance inventory after the sale of the surplus. Enhancing the decision to sell the surplus was the high allowance prices available in the marketplace.

Q. Does Tampa Electric anticipate the sale of surplus SO_2 allowances during 2007?

A. Yes. The company anticipates the sale of approximately $74 million worth of surplus SO_2 allowances during 2007. Additional details associated with the 2007 sale are provided by Tampa Electric Witness, Gregory M. Nelson.

The revenues from the allowance sales have an immediate, direct benefit to Tampa Electric customers since they offset environmental expenses. Form 42-7P of my attached exhibit provides the proposed 2007 ECRC factors by rate class. As demonstrated, the average ECRC factor is a credit of 0.345 cents per kilowatt hour ("kWh") or a credit of $3.45 per 1,000 kWh.

Q. Has Tampa Electric proposed any new environmental compliance projects for ECRC cost recovery for the period from January 2007 through December 2007?

A. Yes. On August 30, 2006, Tampa Electric submitted a petition seeking approval for cost recovery for the Clean Air Mercury Rule ("CAMR") program to the Commission. As stated in Witness Greg M. Nelson's Direct Testimony, the EPA established standards of performance for mercury emissions for new and existing coal-fired electric utility steam generating units as defined in the federal Clean Air Act Section 111, known as CAMR, effective January 2009. CAMR will permanently cap and reduce mercury emissions nation-wide in two phases: Phase I cap is 38 tons per year with a compliance date of 2010 and Phase II cap is 15 tons per year with a compliance date of 2018. The Florida Department of Environmental Protection ("FDEP") administers the CAMR as delineated in Chapter 62-204, 62-210 and 62-296, Florida Administrative Code ("F.A.C.").

Tampa Electric's Big Bend and Polk Power Stations will be affected by the nation-wide mercury emissions reduction rule. To begin the process for rule compliance, the company will install monitoring systems that will sample mercury found in flue gas.

Q. What are the existing capital projects included in the calculation of the ECRC factors for 2007?

A. Tampa Electric proposes to include for ECRC recovery the 22 previously approved capital projects and their projected costs in the calculation of the ECRC factors for 2007. These projects are: 1) Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration, 2) Big Bend Units 1 and 2 Flue Gas Conditioning, 3) Big Bend Unit 4 Continuous Emissions Monitors, 4) Big Bend Unit 1 Classifier Replacement, 5) Big Bend Unit 2 Classifier Replacement, 6) Big Bend Section 114 Mercury Testing Platform, 7) Big Bend Units 1 and 2 FGD, 8) Big Bend FGD Optimization and Utilization, 9) Big Bend NO_x Emissions

Reduction, 10) Big Bend Particulate Matter ("PM") Minimization and Monitoring, 11) Polk NO_x Emissions Reduction, 12) Big Bend Unit 4 SOFA, 13) Big Bend Fuel Oil Tank No. 1 Upgrade, 14) Big Bend Fuel Oil Tank No. 2 Upgrade, 15) Phillips Tank No. 1 Upgrade, 16) Phillips Tank No. 4 Upgrade, 17) Big Bend Unit 1 Pre-SCR, 18) Big Bend Unit 2 Pre-SCR, 19) Big Bend Unit 3 Pre-SCR, 20) Big Bend Unit 4 SCR 21) Big Bend FGD Reliability and 22) SO_2 Emission Allowances. Some of these projects will be described in more detail by Tampa Electric Witness, Gregory M. Nelson.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2007?

A. Yes. Form 42-3P contained in Exhibit No. ___ (HTB-3) summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 26, provides the calculations of the costs which result in recoverable jurisdictional capital costs of $24,087,724.

Q. What are the existing O&M projects included in the calculation of the ECRC factors for 2007?

A. Tampa Electric proposes to include for ECRC recovery the

17 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2007. These projects are: 1) Big Bend Unit 3 FGD Integration, 2) Big Bend Units 1 and 2 Flue Gas Conditioning, 3) SO_2 Emissions Allowances, 4) Big Bend Units 1 and 2 FGD, 5) Big Bend PM Minimization and Monitoring, 6) Big Bend NO_x Emissions Reduction, 7) Polk NO_x Emissions Reduction, 8) Bayside SCR Consumables, 9) Big Bend Unit 4 SOFA, 10) Big Bend Unit 1 Pre-SCR, 11) Big Bend Unit 2 Pre-SCR, 12) Big Bend Unit 3 Pre-SCR, 13) Big Bend Unit 4 SCR, 14) NPDES Annual Surveillance Fees, 15) Gannon Thermal Discharge Study, 16) Clean Water Act Section 316(b) Phase II Study, and 17) Arsenic Groundwater Standard Program. Some of these projects will be described in more detail by Tampa Electric Witness, Gregory M. Nelson.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2007?

A. Yes. Form 42-2P contained in Exhibit No. ___ (HTB-3) summarizes the recoverable jurisdictional O&M costs for these projects which total ($58,152,247) for 2007.

Q. Do you have a schedule providing the description and progress reports for all environmental compliance activities and projects?

A. Yes. Project descriptions and progress reports, as well as the projected recoverable cost estimates, are provided in Form 42-5P, pages 1 through 31.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2007?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total ($34,064,523).

Q. How were environmental cost recovery factors calculated?

A. The environmental cost recovery factors were calculated as shown on Schedules 42-6P and 42-7P. The demand allocation factors were calculated by determining the percentage each rate class contributes to the monthly system peaks and then adjusted for losses for each rate class. The energy allocation factors were determined by calculating the percentage that each rate class contributes to total kWh sales and then adjusted for losses for each rate class. This information was obtained from Tampa Electric's 2004 load research study.

Form 42-7P presents the calculation of the proposed ECRC factors by rate class.

Q. What are the 2007 ECRC billing factors by rate class for which Tampa Electric is seeking approval?

A. The computation of the billing factors is shown on Form 42-7P. In summary, the 2007 proposed ECRC billing factors are credits as follows:

Rate Class	**Factor (¢/kWh)**
Average Factor	(0.345)
RS, RST	(0.344)
GS, GST, TS	(0.345)
GSD, GSDT	(0.347)
GSLD, GSLDT, SBF	(0.345)
IS1, IST1, SBI1, IS3, IST3, SBI3	(0.340)
SL, OL	(0.358)

Q. When does Tampa Electric propose to begin applying these environmental cost recovery credits?

A. The environmental cost recovery credits will be effective concurrent with the first billing cycle for January 2007.

Q. Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2007 through December 2007 consistent with criteria established for ECRC recovery in Order No. PSC-94-0044-FOF-EI?

A. Yes. The costs for which ECRC treatment is requested meet the following criteria:

1. such costs were prudently incurred after April 13, 1993;
2. the activities are legally required to comply with a governmentally imposed environmental regulation enacted, became effective or whose effect was triggered after the company's last test year upon which rates are based; and
3. such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. Please summarize your testimony.

A. My testimony supports the approval of a final average environmental billing factor credit of 0.345 cents per kWh which includes projected capital and O&M revenue requirements of ($34,064,523) associated with a total of 31 environmental projects and a true-up over-recovery provision of $34,738,235 primarily driven by SO_2 allowance sales. My testimony also explains that the projected environmental expenditures for 2007 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 060007-EI
FILED: SEPTEMBER 1, 2006

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GREGORY M. NELSON

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

A. My name is Gregory M. Nelson. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Environmental, Health and Safety in the Generation Services.

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

A. I received a Bachelors Degree in Mechanical Engineering from the Georgia Institute of Technology in 1982 and a Masters of Business Administration from the University of South Florida in 1987. I am a registered Professional Engineer in the State of Florida. I began my engineering career in 1982 in Tampa Electric's Engineering Development Program. In 1983, I worked in the Production Department where I was responsible for power plant performance projects. Since 1986, I have held various environmental permitting and compliance positions. In 1997, I was promoted to Administrator - Air Programs in the Environmental Planning Department. In this position, I was responsible for all air permitting and compliance programs. In 1998, I was promoted to Manager, Environmental Planning and in 2000 I became Director, Environmental Affairs. In 2003, I became Director, Environmental, Health and Safety and my present responsibilities include the management of Tampa Electric's environmental permitting and compliance programs as well as generation safety programs.

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

A. Yes, I have provided testimony regarding environmental projects and their associated environmental requirements in various Environmental Cost Recovery Clause ("ECRC") proceedings before this Commission.

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

A. The purpose of my testimony is to demonstrate that the activities for which Tampa Electric seeks cost recovery through the ECRC for the January 2007 through December

2007 projection period are activities necessary for the company to comply with various environmental requirements. Specifically, I will describe the ongoing activities that are associated with the Consent Final Judgment ("CFJ") entered into with the Florida Department of Environmental Protection ("FDEP") and the Consent Decree ("CD") lodged with the U.S. Environmental Protection Agency ("EPA") and the Department of Justice. I will also discuss other programs previously approved by the Commission for recovery through the ECRC; as well as the Clean Air Mercury Rule ("CAMR") program, a new program the company is currently seeking Commission approval to recover the costs of the program activities through the ECRC. Finally, I will discuss the sulfur dioxide ("SO_2") emission allowance sales for 2007 and how the company is positioned for future allowance needs.

Q. Please provide an overview of the ongoing environmental compliance requirements that are the result of the CFJ and the CD ("the Orders").

A. The general ongoing requirements of the Orders provide for further reductions for SO_2, particulate matter ("PM") and nitrous oxides ("NO_x") emissions at Big Bend Station.

Q. What do the Orders require for SO_2 emission reductions?

A. The Orders require Tampa Electric to create a plan for optimizing the availability and removal efficiency of the flue gas desulfurization systems ("FGD" or "scrubbers"). The plan was submitted to the EPA in two phases, and both were approved.

Phase I required that Tampa Electric work scrubber outages around the clock and with contract labor, when necessary, speed the return of a malfunctioning scrubber to service. In addition, Phase I required Tampa Electric to review all critical scrubber spare parts and increase the number and availability of spare parts to ensure a speedy return to service of a malfunctioning scrubber.

Phase II outlined capital projects that Tampa Electric was to perform to upgrade each scrubber at Big Bend Station. It also addressed the use of environmental dispatching in the event of a scrubber outage. All of the preliminary SO_2 emissions reduction projects have been completed. However, additional work will occur in 2007 associated with the Big Bend Units 1 and 2 FGD and Big Bend FGD Reliability programs to comply with the elimination of the allowed scrubber outage days for 2010 and 2013.

Q. What do the Orders require for PM emission reductions?

A. The Orders require Tampa Electric to develop and implement a best operational practices ("BOP") study to minimize PM emissions from each electrostatic precipitator ("ESP"), complete and implement a best available control technology ("BACT") analysis of the ESPs at Big Bend Station, demonstrate the operation of a PM continuous emissions monitoring system ("CEM") on Big Bend Units 3 and 4 and demonstrate the operation of a second PM CEM on Big Bend Units 1 and 2. Per the Orders, the installation of the second PM CEM is required on or before May 1, 2007, if the first PM CEM has been shown to be feasible and remains in operation and if Tampa Electric advises the EPA that it has elected to continue to combust coal in Big Bend Units 1, 2 and 3. Since the aforementioned conditions have been met, Tampa Electric is required to install the second PM CEM in 2007. In addition, some required BOP projects will occur in the future which is expected to primarily consist of limited wide plate spacing upgrades for Big Bend Units 1 and 3.

Q. Please describe the Big Bend PM Minimization and

Monitoring program activities and provide the estimated capital and O&M expenditures for the period of January 2007 through December 2007.

A. The Big Bend PM Minimization and Monitoring program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. In the Order, the Commission found that the program met the requirements for recovery through the ECRC. Tampa Electric had previously identified various projects to improve precipitator performance and reduce PM emissions as required by the Orders. In 2007, there will be capital expenditures associated with the installation of a second PM CEM, O&M expenses associated with existing and recently installed BOP and BACT equipment and continued implementation of the BOP procedures. These activities are expected to result in approximately $450,000 and $450,000 of capital and O&M expenses, respectively.

Q. What do the Orders require for NO_x reductions?

A. The Orders require Tampa Electric to perform NO_x emissions reduction projects on Big Bend Units 1, 2 and 3 and pursuant to an amendment, for Big Bend Unit 4 to be substituted for Big Bend Unit 3. The NO_x emissions reductions use the 1998 NO_x emissions as the baseline year for determining the level of reduction achieved. Tampa Electric was also required by the Orders to demonstrate innovative technologies or provide additional NO_x technologies beyond those required by the early NO_x emissions reduction activities.

Q. Please describe the Big Bend NO_x Emissions Reduction program activities and provide the estimated capital and O&M expenses for the period of January 2007 through December 2007.

A. The Big Bend NO_x Emissions Reduction program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. In the Order, the Commission found that the program met the requirements for recovery through the ECRC. Tampa Electric will perform the requisite capital replacement and maintenance on the previously approved NO_x reduction projects. These activities are expected to result in approximately $300,000 and $350,000 of capital and O&M expenses, respectively.

Q. Please describe long-term NO_x requirements associated with the Orders and Tampa Electric's efforts to comply with the requirements.

A. The Orders require Big Bend Unit 4 to begin operating with a Selective Catalytic Reduction ("SCR") system or other NO_x control technology, be repowered, or be shut down and scheduled for dismantlement by June 1, 2007. Big Bend Units 1, 2 and/or 3 must either begin operating with an SCR system or other NO_x control technology, be repowered, or be shut down and scheduled for dismantlement one unit per year by May 1, 2008, May 1, 2009 and May 1, 2010, respectively.

In order to meet the NO_x emission rates and timing requirements of the Orders, Tampa Electric engaged an experienced consulting firm, Sargent and Lundy, to assist with the performance of a comprehensive study designed to identify the long-range plans for the generating units at Big Bend Station. The results of the study clearly indicated that the option to remain coal-fired at Big Bend Station and installing the necessary NO_x reduction technologies is the most cost-effective alternative to satisfy the NO_x emissions reductions required by the Orders. This decision was communicated to the EPA and FDEP in August 2004. Tampa Electric also apprised the Commission of this decision in its filing made in Docket

No. 040750-EI in August 2004.

Q. Please describe the Big Bend Units 1 through 3 Pre-SCR and the Big Bend Units 1 through 4 SCR projects and provide estimated capital and O&M expenditures for the period of January 2007 through December 2007.

A. In Docket No. 040750-EI, Order No. PSC-04-0986-PAA-EI, issued October 11, 2004, the Commission approved cost recovery of the Big Bend Units 1 through 3 Pre-SCR and the Big Bend Unit 4 SCR projects. The Big Bend Units 1 through 3 SCR projects were approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0502-PAA-EI, issued May 9, 2005. The purpose of the Pre-SCR technologies is to reduce inlet NO_x concentrations to the SCR systems, thereby mitigating overall SCR capital and O&M costs. These Pre-SCR technologies include neural networks, windbox modifications, secondary air controls and coal/air flow controls. The SCR projects at Big Bend Units 1 through 4 encompass the design, procurement, installation and annual O&M expenses associated with an SCR system for each unit.

The projected costs for the period of January 2007 through December 2007 for which Tampa Electric is seeking ECRC recovery are for the Big Bend Units 1 through 3 Pre-SCR and Big Bend Unit 4 SCR capital and O&M expenditures associated with the engineering, procurement, construction, start-up, tuning, operation and ongoing maintenance for the projects. Specifically, the projected capital and O&M expenditures for the Big Bend Unit 1 Pre-SCR are $300,000 and $75,000, respectively. The projected O&M expenses for the Big Bend Unit 2 Pre-SCR are $75,000. No capital expenditures are anticipated in 2007 for this project. The projected capital expenditures for Big Bend Unit 3 Pre-SCR are $1,999,397. No O&M expenses are expected for this project in 2007. Big Bend Unit 4 SCR will be placed in-service May 2007. The projected capital expenditures for 2007 are $5,939,686. Including these 2007 capital expenditures, the total projected plant in-service amount for 2007 is estimated to be $63,815,761, inclusive of allowance for funds used during construction. The 2007 projected O&M expenses are $1,256,000.

The projected capital expenditures for Big Bend Units 1 through 3 SCR projects are $22,991,714, $24,934,917 and $37,302,469, respectively. However, as stated in Tampa Electric Witness, Howard T. Bryant's Prepared Direct Testimony in this docket, the company will not seek recovery of capital expenditures until the in-service date for each project has occurred.

Q. Please identify and describe the other Commission approved programs you will discuss.

A. The programs previously approved by the Commission include Big Bend Unit 3 FGD Integration, Big Bend Units 1 and 2 FGD, Gannon Thermal Discharge Study, Bayside SCR Consumables, Big Bend Unit 4 Separated Over-fired Air ("SOFA"), Clean Water Act Section 316(b) Phase II Study, Big Bend FGD Reliability, Arsenic Groundwater Standard and CAMR.

Q. Please describe the Big Bend Unit 3 FGD Integration and the Big Bend Units 1 and 2 FGD activities and provide the estimated capital and O&M expenditures for the period of January 2007 through December 2007.

A. The Big Bend Unit 3 FGD Integration program was approved by the Commission in Docket No. 960688-EI, Order No. PSC-96-1048-FOF-EI, issued August 14, 1996. The Big Bend Units 1 and 2 FGD program was approved by the Commission in Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999. In those Orders, the Commission found that the programs met the requirements for recovery through the ECRC. The programs were implemented to meet the SO_2 emissions requirements of the Phase I and II Clean Air Act Amendments ("CAA") of 1990.

The projected January 2007 through December 2007 O&M expenses for the Big Bend Unit 3 FGD Integration project are $4,013,300. No capital expenditures are anticipated for this project. The projected January 2007 through December 2007 capital and O&M expenditures for the Big Bend Units 1 and 2 FGD project are $297,500 and $6,621,900, respectively. The major component of the expenses is projected to be reagents utilized in the scrubbing process with the balance of expenses being incurred for normal maintenance.

Q. Please describe the Gannon Thermal Discharge Study program activities and provide the estimated capital and O&M expenditures for the period of January 2007 through December 2007.

A. The Gannon Thermal Discharge Study program was approved by the Commission in Docket No. 010593-EI, Order No. PSC-01-1847-PAA-EI, issued September 14, 2001. In that Order, the Commission found that the program met the requirements for recovery through the ECRC. For the period of January 2007 through December 2007, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses will be approximately $10,000 for the period.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated capital and O&M expenditures for the period of January 2007 through December 2007.

A. The Bayside SCR Consumables program was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. For the period of January 2007 through December 2007, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses associated with the consumable goods (primarily anhydrous ammonia) will be approximately $76,000 for the period.

Q. Please describe the Big Bend Unit 4 SOFA program activities and provide the capital and O&M expenditures for the period of January 2007 through December 2007.

A. The Big Bend Unit 4 SOFA program was approved by Commission for ECRC recovery in Docket No. 030226-EI, Order No. PSC-03-0684-PAA-EI, issued June 6, 2003. In the Order the Commission found that the program met the requirements for recovery through the ECRC, contingent upon Big Bend Unit 4 remaining coal fired. On August 19, 2004, Tampa Electric submitted a letter to the EPA declaring the intent for Big Bend Units 1 through 4 to remain coal fired and, as such, complied with the applicable provisions of the CD associated with the decision. The SOFA project was completed in 2004. For the period of January 2007 through December 2007, there will be no capital expenditures for this program. Tampa Electric anticipates annual O&M expenses will be approximately $250,000 for the period.

Q. Please describe the Clean Water Act Section 316(b) Phase II Study program activities and provide the estimated capital and O&M expenditures for the period of January 2007 through December 2007.

A. The Clean Water Act Section 316(b) Phase II Study program was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005. For the period of January 2007 through December 2007, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses associated with the sampling activities will be approximately $736,192 for the period.

Q. Please describe the Big Bend FGD Reliability program activities and provide the estimated capital and O&M expenses for the period of January 2007 through December 2007.

A. Tampa Electric's Big Bend FGD Reliability program was approved by the Commission in Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006. The Commission granted cost recovery approval for prudent costs associated with this project. The Big Bend FGD Reliability project will run concurrently with the installation of SCR systems on the generating units.

As stated in Tampa Electric witness Howard T. Bryant's 2006 Actual/Estimated True-up Testimony filed on August 4, 2006, the Office of Public Counsel ("OPC") filed a protest to the aforementioned Commission order on July 21, 2006. Pending the outcome of the protest, the company will proceed with the inclusion of the prudently incurred FGD costs in the ECRC and respond accordingly to OPC's protest.

For the period of January 2007 through December 2007, Tampa Electric will perform work associated with upgrading the mist eliminator systems for Big Bend Units 1 through 4, upgrading the booster fan for Big Bend Units 3 and 4, electrically isolating the FGD systems on Big Bend Units 3 and 4 and other related activities. These activities are expected to result in approximately $6,500,600 of capital expenditures. No O&M expenses are anticipated for the period.

Q. Please describe the Arsenic Groundwater Standard program activities and provide the estimated capital and O&M expenditures for the period of January 2007 through December 2007.

A. The Arsenic Groundwater Standard program was approved by the Commission in Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2006. In that Order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric cost recovery approval for prudently incurred costs. The new groundwater standard applies to Tampa Electric's H.L. Culbreath Bayside, Big Bend and Polk Power Stations.

For the period of January 2007 through December 2007, there will be no capital expenditures for this program;

however, Tampa Electric anticipates O&M expenses associated with the sampling activities will be approximately $105,000.

Q. Please describe the CAMR program activities and provide the estimated capital and O&M expenditures for the period of January 2007 through December 2007.

A. Tampa Electric submitted a petition seeking Commission approval for cost recovery for the CAMR program on August 30, 2006. The EPA established standards of performance for mercury emissions for new and existing coal-fired electric utility steam generating units as defined in the federal CAA Section 111, known as CAMR, effective January 2009. CAMR will permanently cap and reduce mercury emissions nation-wide in two phases: Phase I cap is 38 tons per year with a compliance date of 2010 and Phase II cap is 15 tons per year with a compliance date of 2018. The FDEP administers the CAMR as delineated in Chapter 62-204, 62-210 and 62-296, Florida Administrative Code ("F.A.C.").

Tampa Electric's Big Bend and Polk Power Stations will be affected by the nation-wide mercury emissions reduction rule. The company will install CEMs or sorbent trap monitoring systems that sample mercury found in flue gas.

For the period of January 2007 through December 2007, Tampa Electric anticipates capital expenditures $560,000 for this program. No O&M expenses are expected for this program for 2007.

Q. Please describe how Tampa Electric reached the decision to sell SO_2 emission allowances in 2007 and discuss the company's allowance needs for 2007 and beyond.

A. After the completion of the repowering project at Bayside Power Station, Tampa Electric performed a thorough evaluation of SO_2 emission allowance needs based on current system conditions and those projected to occur over the next 20 years. Current system conditions included the reduction in coal usage due to repowering and the impacts of the CD and CFJ on SO_2 emission allowances. Future conditions took into account generation expansion and the impact of new federal environmental regulations on SO_2 emission allowances, such as the Clean Air Interstate Rule. At the conclusion of the evaluation, it became evident that the company had a significant surplus of allowances that could be sold in the allowance marketplace. Furthermore, there will be an adequate remaining allowance inventory that will meet the company's needs for the next 20 years.

The decision to sell surplus SO_2 allowances was enhanced by the sustained high allowance prices available in the marketplace due to increased industry demand. In balancing the appropriate quantity to sell with the company's expected future needs, Tampa Electric anticipates selling approximately 105,000 allowances in early 2007. The company will continue to evaluate potential sales opportunities of any future quantities of surplus allowances.

Q. Please summarize your testimony.

A. Tampa Electric's settlement agreements with FDEP and EPA require significant reductions in emissions from Tampa Electric's Big Bend and Gannon Stations. The Orders established definite requirements and time frames in which air quality improvements must be made and result in reasonable and fair outcomes for Tampa Electric, its community and customers, and the environmental agencies. My testimony identified projects which are legally required by the Orders. I described the progress Tampa Electric has made to achieve the more stringent environmental standards. I have identified estimated costs, by project, which the company expects to incur in 2007. Additionally, my testimony identified other projects which are required for Tampa Electric to meet environmental requirements and I provided associated 2007 activities and projected expenditures. Finally, I addressed the prudent sales of SO_2 emissions allowances that are anticipated to occur in 2007 and demonstrated that Tampa Electric's approach toward the allowance quantity contained in the sales will not jeopardize the company's long-term future allowance needs.

Q. Does this conclude your testimony?

A. Yes it does.

MS. BROWN: And then, Madam Chairman, staff would ask that the Comprehensive Exhibit List that staff passed out to the Commission and to the parties be marked as Exhibit 1, and then we will get back to that after we hear from Witness Vick.

CHAIRMAN EDGAR: The Comprehensive Exhibit List will be marked as Exhibit Number 1.

(Exhibit 1 marked for identification.)

MS. BROWN: And this would be the time to swear Witness Vick in.

CHAIRMAN EDGAR: Should we bring him forward?

Mr. Vick. And, Mr. Vick, if you would stand and raise your right hand with me.

(Witness sworn.)

MR. STONE: Chairman Edgar, may I inquire?

J.O. VICK

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

DIRECT EXAMINATION

BY MR. STONE:

Q Would you please state your name and business address for the record?

A My name is James O. Vick. My business address is 1189 -- excuse me, One Energy Place, Pensacola, Florida, zip code 32520.

Q And what is your position with Gulf Power Company?

A I'm the Director of Environmental Affairs.

Q Mr. Vick, did you prefile direct testimony on April 3, 2006, consisting of eight pages; August 4, 2006, consisting of six pages; and on September 1, 2006, consisting of 15 pages?

A Yes, sir, I did.

Q Do you have any changes or corrections to that testimony that has been prefiled in this proceeding?

A No, I don't.

Q If I were to ask you the same questions today, would your answers be the same as presented in that prefiled direct testimony?

A Yes, sir, they would.

MR. STONE: Chairman Edgar, I ask that the prefiled testimony of Mr. Vick dated April 3, 2006, August 4, 2006, and September 1, 2006, all be inserted into the record as though read.

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

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 060007-EI
April 3, 2006

Q. Please state your name and business address.

A. My name is James O. Vick and my business address is One Energy Place, Pensacola, Florida, 32520.

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

A. I am employed by Gulf Power Company as the Director of Environmental Affairs.

Q. Mr. Vick, will you please describe your education and experience?

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Masters of Science Degree in Management from Troy State University, Pensacola, Florida. In August 1978 I joined Gulf Power Company as an Associate Engineer, and have since held various engineering positions with increasing responsibilities such as Air Quality Engineer, Senior Environmental Licensing Engineer, and Manager of Environmental Affairs. In 2003, I assumed my present position as Director of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs area to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e., both existing laws and such laws and regulations that may be enacted or amended in the future. In performing this function, I am responsible for numerous environmental activities.

Q. Are you the same James O. Vick who has previously testified before this Commission on various environmental matters?

A. Yes.

Q. Mr. Vick, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's true-up for the period from January 1, 2005 through December 31, 2005.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2005 through December 2005 with the approved estimated true-up amounts.

A. As reflected in Ms. Davis' Schedule 6A, the recoverable capital costs included in the estimated true-up total $22,593,654, as compared to the actual recoverable capital costs of $22,457,108. This results in a small variance of ($136,546) or 0.6%. I will address four projects that contribute to this variance.

Q. Please explain the capital project variance of 13.5% or $1,803 in Sodium Injection (Line Item 1.13).

A. The Sodium Injection program at Plant Smith was approved for recovery through the ECRC in Doc. 990667-EI due to Phase II Acid Rain provisions of the 1990 Clean Air Act Amendments (CAAA). The Smith sodium injection system was the only project included in this line item until the project was expanded during December of 2005. The program expansion included an automatic sodium injection system for Units 4 and 5 at Plant Crist to regulate the amount of sodium added to the coal supply as described in the 2006 ECRC projection filing. This project includes a silo storage tank system and components that inject sodium carbonate directly onto the coal feeder belt to enhance precipitator performance when low sulfur coal is used at Plant Crist. The injection of sodium carbonate as an additive to low sulfur coal reduces opacity levels to maintain compliance with Clean Air Act provisions.

Q. Please explain the (17%) variance of ($1,299) in the Smith Water Conservation (Line Item 1.17).

A. The Plant Smith closed loop cooling project for the laboratory sampling system was placed in service during December 2005. Material expenditures for the chiller were less than expected.

Q. Please explain the (1%) variance of ($138,783) in the Crist DEP Project (Line Item 1.19).

A. The Crist DEP Project deviation was a result of the Crist Unit 6 Selective Non-Catalytic Reduction (SNCR) and other related components being placed in service on a slightly different schedule than projected.

Q. Please explain the capital project variance of ($3,067) or (24.6%) in the Crist Switchyard Stormwater (Line Item 1.20).

A. Construction of the Crist Switchyard Stormwater project was postponed from 2005 to 2006 due to design modifications. These design modifications required additional time for engineering review that delayed the procurement process.

Q. How do the actual O&M expenses for the period January 2005 to December 2005 compare to the estimated true-up?

A. Mrs. Davis' Schedule 4A reflects that Gulf's recoverable environmental O&M expenses for the current period were $3,051,714, as compared to the estimated true-up of $3,432,403. This results in a year-end net variance of $380,689 or 11%. I will address twelve O&M projects and programs that contribute to this variance.

Q. Please explain the variance of ($25,373) in Title V (Line Item 1.3).

A. Gulf Power submitted Title V permit renewal applications for Plants Crist, Smith, and Scholz during 2004. The revised permits became effective on January 1, 2005. The 2005 permit implementation activities were determined to be capital expenditures rather than O&M expenses. These expenditures are included in Line 1.5, CEMS, on Schedule 8A page 5.

Q. Please explain the variance of $5,354 in Asbestos Fees (Line Item 1.4).

A. This deviation primarily resulted from $4,368 being included in December 2005 that was subsequently determined to be unrecoverable. The error was reversed and corrected during January 2006.

Q. Please explain the variance of ($70,460) or (13.2%) in Emission Monitoring (Line Item 1.5 on Schedule 4A).

A. The Plant Daniel emission monitoring maintenance and relative accuracy test audit (RATA) expenses were less than originally projected. The cost per test for the Plant Daniel RATA tests were lower than expected.

Q. Please explain the variance of ($136,605) in the category General Water Quality (Line Item 1.6).

A. This deviation primarily resulted from the 2005 316b impingement and entrainment sampling expenses being less than originally projected. Gulf anticipated FDEP requiring additional sampling as part of the proposal for information collection (PIC) review. These final PIC recommendations were not received during 2005. Gulf expects to receive additional PIC guidance from FDEP during 2006 at which time the projected sampling expenditures may increase. The General Water Quality variance also resulted from the Plant Smith domestic treatment plant operation and maintenance expenses being less than expected for the recovery period and the scope of the Smith biological study being reduced.

Q. Please explain the variance of ($31,244) in the category Groundwater Contamination Investigation (Line Item 1.7).

A. The Molino substation excavation activities were not completed until December 2005 because FDEP concurrence with alternate clean-up levels was not received until November 2005. The Molino project delay prevented Gulf from being able to move forward with other groundwater investigation projects prior to year end.

Q. Please explain the 73% variance of $2,972 in the category Lead and Copper Rule (Line Item 1.9).

A. The Plant Smith chemical usage costs for corrosion control treatment in the potable water system were more than the projected expenses creating a variance in the Lead and Copper Rule line item.

Q. Please explain the variance of ($4,895) in the category entitled Environmental Auditing/Assessment (Line Item 1.10).

A. Plant assessments were completed; however, district environmental assessments were not conducted during 2005 resulting in a deviation in the Environmetal Auditing/Assessment line item. These assessments will be conducted during 2006.

Q. Please explain the variance of $31,643 in the category entitled General Solid & Hazardous Waste (Line Item 1.11).

A. This variance resulted from waste removal and disposal costs for Gulf's distribution systems being more than originally anticipated during normal operations. The amount of solid and hazardous waste generated varies from one period to the next.

Q. Please explain the variance of $32,243 in Above Ground Storage Tanks (Line Item 1.12).

A. This variance primarily resulted from painting the corporate office and district above ground storage tanks. Painting is required to maintain the storage tank systems pursuant to Chapter 62 Part 762, Florida Administrative Code (F.A.C.). This expense was not originally planned for 2005..

Q. Please explain the variance of ($18,584) in Sodium Injection (Line Item 1.16).

A. The expenses that Gulf incurs for this program are dependent on the available coal supply and the necessity for sodium injection. The need for sodium injection was less than what was anticipated for the 2005 projection period.

Q. Please explain the variance of ($8,399) in Line Item 1.17, Gulf Coast Ozone Study (GCOS).

A. Phase III of the GCOS modeling was completed during 2004. The 2005 GCOS projection included final report preparation and review expenses. The report review did not require as many revisions and follow-up items as Gulf had originally anticipated.

Q. Please explain the variance of ($160,282) in Line Item 1.19, FDEP NOX Reduction Agreement.

A. This O&M line item includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the FDEP NOX Reduction Agreement. The anhydrous ammonia and urea expenses are dependent on the available coal supply, unit load, and market value. During 2005, less anhydrous ammonia was required for the selective catalytic reduction (SCR) system than originally anticipated.

Q. Mr Vick, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 060007-EI
August 4, 2006

Q. Please state your name and business address.
A. My name is James O. Vick and my business address is One Energy Place, Pensacola, Florida, 32520.

Q. By whom are you employed and in what capacity?
A. I am employed by Gulf Power Company as the Director of Environmental Affairs.

Q. Mr. Vick, will you please describe your education and experience?
A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Masters of Science Degree in Management from Troy State University, Pensacola, Florida. I joined Gulf Power Company in August 1978 as an Associate Engineer. I have since held various engineering positions with increasing responsibilities such as Air Quality Engineer and Senior Environmental Licensing Engineer. In 2003, I assumed

my present position as Director of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs section to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e., both existing laws and such laws and regulations that may be enacted or amended in the future. In performing this function, I am responsibile for numerous environmental activities.

Q. Are you the same James O. Vick who has previously testified before this Commission on various environmental matters?

A. Yes.

Q. Mr. Vick, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's estimated true-up for the period from January 1, 2006 through December 31, 2006. This true-up is based on six months of actual and six months of projected expenses.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the estimated true-up calculation for the period January 1, 2006 through December 31, 2006 with approved projected amounts.

A. As reflected in Ms. Martin's Schedule 6E, the recoverable capital costs approved in the original projection total $29,608,324, as compared to the estimated true-up amount of $29,694,980. This results in a projected variance of $86,656 or 0.3%. There are five capital projects and programs that contributed to the majority of this variance: Air Quality Assurance Testing; Precipitator Upgrades for Compliance Assurance Monitoring (CAM); Plant Groundwater Investigation; Crist Condenser Tubes, and finally, SO_2 allowances. The variances for these projects are discussed below.

Q. Please explain the capital project variance of ($14,477) in Air Quality Assurance Testing (Line Item 1.1).

A. The Air Quality Assurance Testing variance is due to an over estimation of amortization in the projection filing.

Q. Please explain the variance of ($109,224) in the capital category entitled Precipitator Upgrades for CAM compliance (Line Item 1.22).

A. The CAM variance primarily resulted from timing delays associated with the Smith Unit 1 precipitator expenditures. Material expenses are also expected to be less than originally projected because the successful bid was lower than Gulf's initial cost projection.

Q. Please explain the variance of ($18,991) in the capital category entitled Plant Groundwater Investigation (Line Item 1.23).

A. The Line Item 1.23 variance resulted from postponing the Plant Groundwater Investigation capital projects. These projects have been delayed until Gulf receives Florida Department of Environmental Protection's response to the Plant Crist and Plant Scholz groundwater studies.

Q. Please explain the variance of $146,259 in the capital category entitled Crist Condenser Tubes (Line Item 1.25).

A. The variance in Line Item 1.25, Crist Condenser Tubes, is primarily due to additional repair work that was required in conjunction with the condenser tube installation. These repairs were not included in the original scope of work.

Q. Please explain the $161,890 variance in SO_2 allowances in Line Item 1.26.

A. Gulf purchased allowances a month earlier and at a higher cost per allowance than originally anticipated. Allowance pricing varies with the daily market.

Q. How do the estimated/actual O&M expenses compare to the original projection?

A. Ms. Martin's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated to be $10,612,425 as compared to the original projection of $13,369,436. This will result in a year-end variance of ($2,757,011). There are five O&M projects and programs that contributed to the majority of this variance that I will discuss – Asbestos Fees; Environmental Auditing / Assessment; General Solid and Hazardous Waste; FDEP NOx Reduction Agreement; and SO_2 Allowances.

Q. Please explain the ($4,869) variance in Asbestos Fees (Line Item 1.4).

A. This deviation primarily resulted from $4,369 being included in December 2005 that was subsequently determined to be unrecoverable. The error was reversed and corrected during January 2006.

Q. Please explain the variance of $11,672 in the category entitled Environmental Auditing/Assessment (Line Item 1.10).

A. The 2005 District environmental assessments were rescheduled for first quarter 2006 after the 2006 Environmental Cost Recovery Clause (ECRC) projection filing submittal. This postponement created a deviation in the Environmental Auditing/Assessment line item.

Q. Please explain the variance of $34,960 in General Solid and Hazardous Waste (Line Item 1.11).

A. This variance resulted from waste removal and disposal costs for Gulf's distribution system being more than originally anticipated during normal operations. The amount of solid and hazardous waste generated varies from one period to the next.

Q. Please explain the variance of ($2,217,690) in Line Item 1.19, FDEP NOx Reduction Agreement.

A. The FDEP NOx Reduction Agreement (Line Item 1.19) includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the Plant Crist FDEP Agreement for Ozone Attainment. The variance in this line item primarily resulted from urea usage being less than originally anticipated for the selective non-catalytic reduction (SNCR) systems. The original cost projection was based on the estimated annual urea usage;

however, the Unit 4 and Unit 5 SNCRs were not placed in service until April 2006. In addition, industry standards and estimates were used for the original projection whereas the updated projection is based on site specific usage.

Q. Please explain the ($569,345) variance in SO2 allowances in Line Item 1.20.
A. Due to the volatility of the allowance market, the Company's proceeds from the spring allowance auction and associated gains returned to customers were difficult to predict and, therefore, were not included in the projection for the current period.

Q. Does this conclude your testimony?
A. Yes.

GULF POWER COMPANY
Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
James O. Vick
Docket No. 060007-EI
September 1, 2006

Q. Please state your name and business address.

A. My name is James O. Vick and my business address is One Energy Place, Pensacola, Florida, 32520.

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

A. I am employed by Gulf Power Company as the Director of Environmental Affairs.

Q. Mr. Vick, will you please describe your education and experience?

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Masters of Science Degree in Management from Troy State University, Pensacola, Florida. I joined Gulf Power Company in August 1978 as an Associate Engineer. I have since held various engineering positions with increasing responsibilities such as Air Quality Engineer, Senior Environmental Licensing Engineer, and Manager of Environmental Affairs. In 2003, I assumed my present position as Director of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs section to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e., both existing laws and such laws and regulations that may be enacted or amended in the future. In performing this function, I have the responsibility for numerous environmental activities.

Q. Are you the same James O. Vick who has previously testified before this Commission on various environmental matters?

A. Yes.

Q. Mr. Vick, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's projection of environmental compliance costs recoverable through the Environmental Cost Recovery Clause (ECRC) during the period from January 2007 through December 2007.

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

A. Yes, I have. My exhibit includes the following documents:

- Florida Clean Air Interstate Rule (FCAIR)
- Florida Clean Air Mercury Rule (FCAMR)

- Plant Crist National Pollutant Discharge Elimination System (NPDES) permit
- Plant Scholz NPDES permit

Counsel: We ask that Mr. Vick's' Exhibit consisting of four documents be marked as Exhibit No. _____(JOV-1).

Q. Mr. Vick, please identify the capital projects included in Gulf's ECRC projection filing.

A. A listing of the environmental capital projects for which Gulf seeks recovery through the ECRC has been provided to Ms. Martin and is included in Schedules 3P and 4P of her testimony. Schedule 4P reflects the expenditures, clearings, retirements, salvage and cost of removal currently projected by month for each of these projects. These amounts were provided to Ms. Martin, who has compiled the schedules and calculated the associated revenue requirements for Gulf's requested recovery.

Q. Have all of the capital projects shown on Ms. Martin's schedules been previously approved by the Commission?

A. No. Gulf's 2007 ECRC capital projection includes two new compliance programs in addition to capital programs previously approved by the Commission. One of these new programs falls under the umbrella heading of Air Quality programs while the other new program falls under the umbrella heading of Water Quality programs.

Q. Mr. Vick, please describe the new program that falls under the Air Quality program heading that is to be considered for cost recovery.

A. The first new program, (Line Item 1.26), is the CAIR/CAMR Compliance Program. This program is necessary to comply with Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) regulations promulgated by the United States Environmental Protection Agency (EPA) in March 2005 and subsequently adopted by the Florida Department of Environmental Protection (FDEP) in June 2006.

The EPA's CAIR, which is published in Chapter 40 of the Code of Federal Regulations (CFR) Parts 51, 72, 73, 74, 77, 78, and 96, restricts sulfur dioxide ("SO_2") and nitrogen oxide ("NOx") air emissions that contribute to fine particulate and ground level ozone in downwind states. The basic EPA requirements were subsequently adopted by FDEP on June 29, 2006 in Chapter 62 Florida Administrative Code (F.A.C.) Parts 204, 210, and 296. The CAIR will use a two-phase cap and trade approach to reduce NOx and SO_2 emissions from electric generating units in 28 eastern states including Florida starting in 2009 and 2010, respectively. The emissions controlled by the CAIR requirements are also impacted by a separate regulatory scheme that will require Gulf to meet the Best Available Retrofit Technology (BART) emission control requirements under the Regional Haze Rule. The Regional Haze Rule was promulgated by EPA on July 6, 2005 to reduce visibility impairing pollutants from twenty-six source categories, including electric generating units. The FDEP will begin rulemaking in September 2006 to adopt a State Implementation Plan requiring BART-eligible sources (generating units built between 1962 and 1977, which have the potential to emit more than 250 tons per year of any visibility impairing pollutant) to propose BART controls or to demonstrate through modeling why they should be exempt from BART regulation. Both EPA and FDEP have indicated that compliance with CAIR through retrofit technology added to generating units to control emissions may also meet the BART requirements of the Regional Haze Rule. This dual compliance benefit would not be available if a strategy of exclusively purchasing allowances is used to meet the requirements of the CAIR rule.

The CAMR (Chapter 40 CFR Parts 60, 72, and 75) limits mercury emissions from new and existing coal-fired power plants. Like CAIR, CAMR will also be implemented through a market-based cap and trade approach, achieving a reduction in mercury emissions in two phases of approximately 20% by 2010 and approximately 70% by 2018. The basic EPA requirements of CAMR were also adopted by FDEP on June 29, 2006 in Chapter 62 of the Florida Administrative Code, Parts 204, 210, and 296. The State of Mississippi plans to adopt verbatim the EPA CAIR and CAMR rules later this year.

Immediately after the passage of the EPA CAIR and CAMR in 2005, Gulf began extensive engineering, design, and other planning activities in order to be prepared to move ahead with the most reasonable strategy for compliance with the CAIR and CAMR requirements once they were adopted by Florida. This strategy was finalized shortly after the adoption of the Florida CAIR and CAMR this past June and implementation has begun. Due to the applicability of the Commission's rule regarding use of AFUDC, the program requirements for Gulf's CAIR/CAIR strategy do not begin impacting ECRC revenue requirements until 2007.

For the 2007-2012 time period, Gulf's CAIR/CAMR Compliance Program will require the installation of Scrubbers at Plants Crist (2009) and Daniel (2011), Selective Catalytic Reduction (SCR) control technology at Plant Crist on Unit 6 (2010), Selective Non-Catalytic Reduction (SNCR) controls at Plants Smith (2009), Scholz (2010), and Daniel (2009), as well as Low NOx burners at Plant Daniel (2009). It will also require new mercury emission monitoring equipment for mercury compliance verification at all of Gulf's generating units (2007-2008) as well as the Plant Daniel units (2007-2008).

For the 2013-2017 time period, Gulf's CAIR/CAMR Compliance Program is currently projected to include the addition of a scrubber and a baghouse at Plant Smith and SCRs at Plant Daniel. The in-service dates for this equipment will be partially determined by the final BART rules and the onset of Phase II of the Florida CAIR, the Florida CAMR, the Mississippi CAIR, and the Mississippi CAMR.

For the purpose of the 2007 projection of ECRC revenue requirements, the Plant Crist scrubber project will incur expenditures totaling $34.4 million. This will include relocating the Unit 7 cooling tower and several sections of existing transmission lines. These activities will be completed during 2007 to create space for construction of the scrubber vessel and other ancillary equipment. Other 2007 projected expenditures include materials, site preparation, and foundation construction as well as detailed engineering and design costs. The 2007 projected expenditures for the Smith SNCRs, totaling $3.5 million, and the Daniel Low NOx burners, $540,000, primarily include expenditures for engineering and material procurement. The projected 2007 expenditures for installation and certification of new mercury emissions monitoring systems to comply with CAMR are $1.4 million.

Q. Mr. Vick, please describe the new Water Quality program that Gulf seeks to recover.

A. The second new capital project program (Line Item 1.27) is the General Water Quality Sampling Boat. Gulf expects to incur capital expenditures of $28,600 during 2007 to purchase a boat for new surface water sampling that is required by the Plant Crist and Plant Scholz NPDES permits. Pursuant to Chapter 62 Part 302.520(1), F.A.C., the FDEP has included new requirements in Gulf's recently issued NPDES permits for both Plants Crist and Scholz. These permits require Gulf Power to establish a biological evaluation plan and implementation schedule for each plant. Gulf must now evaluate the effects from each plant's water discharge on the biological communities in the receiving water bodies. Additional monitoring of aquatic species in each plant's respective receiving water must be conducted to comply with these new permit conditions. Plant Crist's Plan must be submitted no later than November 14, 2007 and monitoring will most likely begin in 2008. Plant Scholz's

Plan was submitted during January 2006 and monitoring will begin in 2007. In addition, these NPDES permits, also have a condition that requires compliance with 40 CFR Part 125.95(a)(1) and (2), also known as 316(b), which requires monitoring aquatic communities to determine the effects of impingement and entrainment on organisms within each plant's once through cooling water systems. Purchasing a boat to conduct these studies in-house will reduce a portion of the anticipated 316(b) expenses that are currently being recovered through the ECRC as part of the previously approved Cooling Water Intake Program.

Q. Mr. Vick, please identify expenditures for the 2007 projection period related to expansions of previously approved capital projects that are required for environmental compliance.

A. There are five other previously approved capital projects that have additional capital expenditures. Three of the projects are related to Gulf's existing Air Quality programs: Continuous Emission Monitoring (CEMs) replacements, Precipitator Upgrades for Compliance Assuance Monitoring (CAM) Compliance, and the Plant Crist FDEP Agreement for Ozone Attainment. The Plant Groundwater Investigation project and the SO_2 allowances will also have projected expenditures in 2007.

<u>1. CEMs (Line 1.5)</u> -- During the 2007 recovery period the CEMs project includes the replacement of flow monitors at Plant Smith and Plant Daniel. Flow monitors are necessary in order to provide the accuracy and reliability needed to measure SO_2 and NOx for compliance with Chapter

40 CFR Part 75 under the Acid Rain Program. The existing monitors are approaching the end of their useful lives, and will be retired upon replacement. The 2007 expenditures are expected to be $313,238.

2. Precipitator Upgrades for CAM Compliance (Line Item 1.22) -- CAM requirements are regulated under Chapter 40 CFR Part 64 which requires a method of continuously monitoring pollution control equipment. Opacity can be used as a surrogate parameter if the precipitator demonstrates a correlation between opacity and particulate matter. Gulf demonstrated this correlation by stack testing in 2003 and 2004, and submitted the results to the FDEP as part of a CAM plan in Gulf's Title V Air Permit renewals in 2004. The precipitator upgrades that are included under this line item on Ms. Martin's schedules are necessary to meet the more stringent surrogate opacity standards under CAM. The Plant Smith Unit 1 precipitator upgrade which was initiated in 2006 will be completed during the second quarter of 2007. In addition, precipitator upgrades are planned for Plant Scholz Unit 2 and Plant Crist Units 4 & 5 in 2007. The Scholz project will be placed in-service during 2007, however the Crist projects will not be completed until 2008. Gulf's projected 2007 expenditures for CAM precipitator upgrades are $12.4 million.

3. Crist FDEP Agreement for Ozone Attainment (Line 1.19) -- For the 2007 projection, Gulf has included capital costs associated with implementation of the Plant Crist FDEP Agreement for Ozone Attainment to meet the terms of the August 28, 2002 agreement with FDEP. Gulf will

be replacing the SCR catalyst and installing an additional ash piping system to manage waste products associated with the operation of the SCR system on Crist Unit 7. The projected 2007 expenditures for the Crist FDEP Agreement project is $2.24 million.

4. Plant Groundwater Investigation (Line Item 1.23) -- The FDEP published a new arsenic groundwater standard that lowered the limit from 0.05 mg/L to 0.01 mg/L, effective January 1, 2005. Gulf expected to incur capital expenditures during 2006 to ensure continued compliance with the arsenic groundwater standards; however these projects have been postponed until Gulf receives FDEP's response to the Plant Crist and Plant Scholz groundwater studies. The 2007 projected expenditures for the Plant Groundwater Investigation are $350,000.

5. SO_2 Allowances (Line Item 1.28) -- Gulf Power has included the purchase of additional SO_2 allowances in the 2007 projection filing. Part of Gulf's strategy to comply with the Clean Air Act Amendments (CAAA) of 1990 was to bring several of Gulf's Phase II generating units into compliance early and bank the SO_2 allowances associated with those units. This bank has slowly been drawn down over the years due to more allowances being consumed than are allocated to Gulf by EPA. Gulf plans to meet this shortfall by using forward contracts to secure 15,000 year 2007 vintage allowances. Additional forward contracts for future vintage year allowances will be executed if future forecasts predict a continuous need. Gulf's strategy also includes possible spot market

purchases of allowances as prices dictate. The reasoning behind the strategy of forward contracts and spot market purchases to secure allowances in 2007 is Gulf's concern over the availability and the price of SO_2 allowances as the compliance deadline for CAIR approaches. Many utilities are no longer selling any allowances in anticipation of their own shortfall in the coming years.

Q. Please compare the Environmental Operation and Maintenance (O&M) activities listed on Schedule 2P of Ms. Martin's Exhibit to the O&M activities approved for cost recovery in past ECRC proceedings.

A. All of the O&M activities listed on Schedule 2P have been approved for recovery through the ECRC in past proceedings.

Q. Please describe the O&M activities included in the Air Quality category that have projected expenses in 2007.

A. There are five O&M activities included in the Air Quality category that have projected expenses in 2007. On Schedule 2P, Air Emission Fees (Line Item 1.2), represents the expenses projected for the annual fees required by the CAAA that are payable to the FDEP. The expenses projected for the recovery period total $779,874.

Included in the Air Quality category, Title V (Line Item 1.3), represents projected expenses associated with the implementation of the Title V permits. The total estimated expenses for the Title V Program during 2007 are $87,456.

On Schedule 2P, Asbestos Fees (Line Item 1.4), consists of the fees required to be paid to the FDEP for the purpose of funding the State's asbestos abatement program. The expenses projected for the recovery period total $2,250.

Emission Monitoring (Line Item 1.5) on Schedule 2P reflects an ongoing O&M expense associated with the Continuous Emission Monitoring equipment as required by the CAAA. These expenses are incurred in response to EPA's requirements that the Company perform Quality Assurance/Quality Control (QA/QC) testing for the CEMs, including Relative Accuracy Test Audits (RATAs) and Linearity Tests. Other activities within this category include the testing, development, and implementation of new compliance assurance monitoring requirements associated with the Clean Air Act Amendment. The expenses expected to occur during the 2007 recovery period for these activities total $580,357.

The FDEP NOx Reduction Agreement (Line Item 1.19), includes the O&M cost associated with the Plant Crist Unit 7 SCR and Crist Units 4-6 SNCR projects that were included as part of the 2002 agreement with FDEP. This O&M line item includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the Agreement. Gulf was granted approval for recovery of the costs incurred to complete these activities in Docket No. 020943-EI through Order Number PSC-02-1396-PAA-EI. The projected expenses for the 2007 recovery period total $3,071,207.

Q. What O&M activities are included in Water Quality?

A. The first activity, General Water Quality (Line Item 1.6), identified in Schedule 2P, includes Soil Contamination Studies, Dechlorination, Groundwater Monitoring Plan Revisions, Surface Water Studies, and the Cooling Water Intake Program. The expenses expected to be incurred during the projection period for this line item total $485,287.

The second activity listed in the Water Quality Category, Groundwater Contamination Investigation (Line Item 1.7), was previously approved for environmental cost recovery in Docket No. 930613-EI. This activity is projected to incur incremental expenses totaling $1,352,251.

Line Item 1.8, State NPDES Administration, was previously approved for recovery in the ECRC and reflects expenses associated with annual fees for Gulf's three generating facilities in Florida. These expenses are expected to be $42,000 during the projected recovery period.

Finally, Line Item 1.9, Lead and Copper Rule, was also previously approved for ECRC recovery and reflects sampling, analytical and chemical costs related to lead and copper in drinking water. These expenses are expected to total $10,000 during the 2007 projection period.

Q. What activities are included in the Environmental Affairs Administration Category?

A. Only one O&M activity is included in this category on Schedule 2P (Line Item 1.10) of Ms. Martin's exhibit. This line item refers to the Company's Environmental Audit/Assessment function. This program is an on-going compliance activity previously approved for ECRC recovery. Expenses totaling $4,300 are expected during the 2007 recovery period.

Q. What O&M activities are included in the General Solid and Hazardous Waste category?

A. Only one program, General Solid and Hazardous Waste (Line Item 1.11) is included in the Solid and Hazardous Waste category on Schedule 2P. This activity involves the proper identification, handling, storage, transportation and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. This program is a previously approved program that is projected to incur incremental expenses totaling $485,428.

Q. In addition to the four major O&M categories listed above, are there any other O&M activities which have been approved for recovery that have projected expenses?

A. Yes. There are three other O&M categories that have been approved in past proceedings which have projected expenses. They are the Above Ground Storage Tanks program, the Sodium Injection System, and SO_2 Allowances.

Q. What O&M activities are included in the Above Ground Storage Tanks category?

A. Only one program, Above Ground Storage Tanks (Line Item 1.12), is included in this category. This program is expected to incur $101,050 of expenses during 2007.

Q. What activity is included in the Sodium Injection (Line Item 1.16) category?

A. The Sodium Injection System, approved in Docket Number No. 990667-EI for inclusion in the ECRC, involves sodium injection to the coal supply to enhance precipitator efficiencies when burning certain low sulfur coals at the plant. The line item projected expenses for the 2007 recovery period total $275,000.

Q. Please describe the activity included in the SO_2 Allowances (Line Item 1.20).

A. This program includes expenses for SO_2 allowances for Gulf's generating plants. The purchase of additional allowances has increased the weighted average cost of allowances being expensed.

Q. Mr. Vick, does this conclude your testimony?

A. Yes.

BY MR. STONE:

Q Mr. Vick, there was one composite exhibit to your testimony, is that correct?

A That's correct.

Q And that has been premarked as Exhibit JOV-1?

A That is correct.

MR. STONE: Chairman Edgar, I would ask that we identify that with a hearing exhibit number for the record.

MS. BROWN: Madam Chairman, that would be as listed on the Comprehensive Exhibit List. It would be Exhibit Number 3.

CHAIRMAN EDGAR: Exhibit Number 3 as listed on the Comprehensive Exhibit List, or Composite Exhibit List.

BY MR. STONE:

Q Mr. Vick, would will you please summarize your testimony?

A Yes, sir. Issue 12A concerns the CAIR CAMR Compliance Program. This program is necessary to comply with the requirements of the Clean Air Interstate Rule and the Clean Air Mercury Rule that were promulgated by the United States Environmental Protection Agency in March of 2005, and subsequently adopted by the Florida Department of Environmental Protection in June of 2006.

The EPA Clean Air Interstate Rule, or CAIR, as it is commonly referred to, restricts sulfur dioxide and nitrogen oxide emissions that contribute to fine particulate and ground level ozone in downwind states. The CAIR utilizes a two-phase cap and trade approach to reduce sulfur dioxide and nitrogen oxide emissions from electric generating units in 28 eastern states, including the state of Florida.

The Clean Air Mercury Rule, or CAMR, as it is commonly referred to, limits mercury emissions from new and existing coal-fired power plants. Like CAIR, the CAMR will also be implemented through a market-based cap and trade approach achieving a reduction in mercury emissions in two phases of approximately 20 percent by 2010 and 70 percent in 2018.

Immediately after the passage of the EPA CAIR and CAMR regulations in 2005, Gulf Power began extensive planning, engineering, and design in order to be prepared to move ahead with the most reasonable least cost strategy for compliance with the CAIR and CAMR requirements once they were adopted by the state of Florida. This strategy was finalized shortly after adoption of the Florida CAIR and CAMR rules this past June and implementation of that strategy has begun.

For the purpose of the 2007 ECRC revenue requirements, the CAIR and CAMR compliance program includes portions of the Plant Crist scrubber project that will be placed in service during 2007. Engineering and procurement expenditure for the Smith selective noncatalytic reduction devices and the Daniel low NOX burners, as well as installation and certification of mercury emission monitoring systems. These projects are a portion of Gulf's overall CAIR/CAMR compliance strategy that will be implemented over the next ten years.

As the individual responsible for assuring that the company will be in compliance with any new environmental requirements, I have the responsibility to formulate and implement the company's environmental strategy to comply with these new requirements. The CAIR and CAMR compliance program was developed under my supervision through our planning and evaluation process to address the requirements of the CAIR/CAMR, and I fully support the implementation of this program to be the most reasonable and prudent method of complying with the new regulations.

MR. STONE: With that, Chairman Edgar, we submit Mr. Vick for Commissioner Arriaga's questions.

CHAIRMAN EDGAR: Thank you. Commissioner.

COMMISSIONER ARRIAGA: Thank you.

Good morning, Mr. Vick.

THE WITNESS: Good morning.

COMMISSIONER ARRIAGA: I had the pleasure of paying a visit to the Crist Plant, and you were a very good hosts when I was there. It is an interesting experience. I was actually very positively surprised by the mercury research center that you are running over there and all the things that you are doing. It's fantastic, and I want to congratulate you on that.

THE WITNESS: Thank you.

COMMISSIONER ARRIAGA: In reading your testimony, I have no concerns regarding the legality or the statutory needs to comply with this investment. I only have some questions regarding the financial analysis that you did in order to come up with this proposal.

First of all, you state that the 2007 incurred expenditures will total $34.4 million. In reading through the material, I didn't find any statement regarding the total investment, the total capital expenditure you're going to make to add the scrubbers to Plant Crist. How much is it going to cost at the end of the day?

THE WITNESS: Commissioner, the numbers that obviously were filed were for the purposes of what would actually go plant-in-service in 2007. Obviously when there is a scrubber project of this magnitude, typically we look for a three-year window for just construction purposes alone. The bottom line on the scrubber project at Plant Crist, which will entail Units 4 through 7, or a scrubber for Crist 4 through 7 will be -- and this is with AFUDC -- is $550,995,000.

COMMISSIONER ARRIAGA: Is this somewhere in the testimony that you filed, because I couldn't find that figure?

THE WITNESS: No, sir, it is not.

COMMISSIONER ARRIAGA: I would like to ask staff, Madam Chairman, how is it that you propose a stipulation on something that you didn't have a final figure for the amount of the investment?

MR. BREMAN: That was part of our settlement. Our stipulation, the one that we support here, is that the company will be filing more detailed testimony in the spring of 2007.

We are mindful that in June of 2007, we have final rules out, even though FPL is litigating that, and that is addressed in Mr. LaBauve's testimony with FPL. The companies are moving forward with compliance options, and we are moving from a generic strategy to actually bricks and mortar and contracts. So it is at the time that the company actually makes commitments to move forward that the company needs to then come forward to the Commission and explain exactly what they did and how they're going about concluding that it is the least-cost option.

COMMISSIONER ARRIAGA: And you are comfortable with this $560 million investment that is going to be made as a round ballpark figure?

MR. BREMAN: I think this is going to be an ongoing review. We haven't seen the testimony yet. What we are here today in staff's mind is we are saying that we know that there is an environmental requirement and that the company has to comply with those requirements, and that those costs are incremental to base rates. So that's pretty much the decision that we are making today. The review of the actual choices will be an ongoing effort.

COMMISSIONER ARRIAGA: Thank you.

Mr. Vick, what I'm trying to get at is I saw Plant Crist. It is a almost depreciated plant. What went through your mind when you did the economic financial analysis of justifying an investment of $600 million almost on a plant that is near its end life probably? And if it is not, if it is going to be around for 10 or 15 more years, operation and maintenance of this plant, its costs aren't going to increase over the years? How did you financially justify that, because I didn't see that analysis in the testimony here?

THE WITNESS: No, sir, that financial analysis was not in the testimony. The process that we go through is an annual process that has actually been in place since the Clean Air Act Amendments of 1990. We came to the Commission back in the early '90s with the plan to comply with Phase I, which Phase I actually would start in January 1, 1995, and run through 1999 when Phase II would kick in in January 1 of 2000.

Basically, we had some similar regulations basically restricting sulfur dioxide emissions. We came to the Commission with a plan back in that time frame showing what we were going to be doing. Obviously, a long-term strategy, and particularly in the case of what we are dealing with here with

CAIR and CAMR, is going to be a dynamic one. Obviously as the compliance deadlines near, and in this case we have got to be in compliance with the NOX requirements January 1, 2009, the SO2 requirements in January 1 of 2010, the strategy dictates that the controls we are going to be putting on need to be started now.

Now, as part of that process there is a -- as I said, we do have an annual process that has been going on since the early '90s. We continue to refine that process on an annual basis, and in the last couple years, particularly with CAIR and CAMR, there may be even more than an annual review at times to make sure that what we did six months ago is still on track.

But there is a process that we go through. And if you like, I've got a couple of poster boards I would be more than glad to kind of go through that process with you. I've got some handouts that we could pass out to you so you don't have to strain your eyes on the poster board, if that would be okay. I can go through that process if you like.

COMMISSIONER ARRIAGA: No, I don't think it's necessary. Staff just mentioned the fact that this is an on-going process. What I'm trying to point out to you, and I would appreciate it so much for my own knowledge, is over the next four or five months if you could present to staff the economic analysis that justifies an investment of $600 million in a plant that is almost totally depreciated. In other words, why did you fix the old Chevy when you could have bought a Lexus, more or less, in colloquial terms?

THE WITNESS: We are prepared to make that financial analysis. We can do that. No problem.

COMMISSIONER ARRIAGA: Thank you so much.

That's all, Madam Chair.

CHAIRMAN EDGAR: Mr. Stone.

MR. STONE: That concludes our testimony. It's my understanding that Mr. Vick's exhibit is part of the comprehensive exhibit, and so it will be a part when that exhibit is moved into evidence.

MS. BROWN: And, Madam Chairman, when I was suggesting the number to mark Mr. Vick's exhibits, I noticed what you were trying to tell me earlier today, there was a problem with the numbers. So I would like at this point to fix that before we move the exhibit list into the record.

CHAIRMAN EDGAR: Okay.

MS. BROWN: Starting with Mr. Vick's testimony, which on the exhibit list is Exhibit 2, that should be changed to 3, and then subsequently all the exhibits after that should be changed accordingly.

CHAIRMAN EDGAR: Okay. The Comprehensive Exhibit List will be entered into the record with the renumbering as just described by our staff counsel.

MS. BROWN: Thank you, Madam Chairman.

(Exhibits 1 through 26 admitted into the record.)

With that, we are ready to proceed with the bench decision on the stipulated issues in the case if the Commission is ready.

CHAIRMAN EDGAR: Commissioners, before we go right into the issues, are there any other questions, general questions, or specific questions for any of the parties, or for our staff? Seeing none.

Then, as Ms. Brown has described, we are in the posture to consider motions on the stipulated issues that are before us. My suggestion is that we take up the company-specific stipulations first as there will be some fallout then on the generic issues. The company-specific stipulations are on Pages 11 through 14 on the prehearing order beginning with Issue 9A, and then running through Issue 12C.

And before I look to see if we are ready for a motion or discussion, I did have one question on Issue 9C specifically, and I'm going to look to our staff first. Okay. On Issue 9C, the position description in the prehearing order do show OPC in particular and some of the others as raising the issue as to whether the legal fees would be an inappropriate use of the clause.

On an issue on legal expenses in another hearing last year, I did have some questions about whether legal expenses had been covered in base rates. And I realize that we have a revised stipulated position list, but I would just like to ask our staff to respond specifically to the question of are the legal expenses that have been raised in this issue before us today, are they included in base rates?

MR. SLEMKEWICZ: John Slemkewicz with the staff.

Based on interrogatories that I proposed to the company and their responses, and my review of the MFRs from the last stipulated rate case, the legal expenses related to CAIR are not in base rates. They are more of an unusual nature and they are not normally covered in base rates.

CHAIRMAN EDGAR: So in this instance they are not covered in base rates?

MR. SLEMKEWICZ: That's correct.

CHAIRMAN EDGAR: Okay. Ms. Christensen.

MS. CHRISTENSEN: At this point OPC is taking no position on that. With that understanding, we're going to assume a no position on this issue.

CHAIRMAN EDGAR: Okay. Commissioners, any other questions on any of the company-specific stipulated issues that are before us? No.

COMMISSIONER DEASON: Madam Chairman, I can move the stipulated issues which are company-specific, which would include Issues 9A through 12C.

COMMISSIONER CARTER: Second.

CHAIRMAN EDGAR: Commissioners, we have a motion and a second on Issues 9A through 12C. Any further discussion?

Seeing none. All in favor of the motion say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed?

Show the motion adopted.

Commissioners, that brings us to the generic issues, which are contained on Page 6 through Page 10 of the prehearing order? Are there any questions for our staff or for the parties on any of these issues?

Seeing none. Is there a motion?

COMMISSIONER DEASON: Well, Madam Chairman, I guess I have a question.

CHAIRMAN EDGAR: Now is there a question?

COMMISSIONER DEASON: Yes.

Given the previous vote on the company-specific issues, then staff is in the position to have all of the numbers for all of the general issues, is that correct?

MR. BREMAN: Yes.

COMMISSIONER DEASON: And that would be Issues 1 through 7, or 1 through 8, is that correct?

MS. BROWN: That's correct.

COMMISSIONER DEASON: Madam Chairman, I would move approval of Issues 1 through 8.

COMMISSIONER CARTER: Second.

CHAIRMAN EDGAR: Commissioners, we have a motion and a second on Issues 1 through 8. Any further discussion?

Seeing none. All in favor of the motion say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed?

Show the motion adopted.

Ms. Brown.

MS. BROWN: Madam Chairman, as far as I know there are no other matters to be addressed. No post-hearing filings are necessary because of the bench decision, and staff notifies the parties that an order will issue by November 27th.

CHAIRMAN EDGAR: Okay. Then, Commissioners, parties, and interested persons, we have concluded our business on the 07 docket. Thank you all.

COMMISSIONER ARRIAGA: Madam Chair.

CHAIRMAN EDGAR: Commissioner Arriaga?

COMMISSIONER ARRIAGA: The witness.

CHAIRMAN EDGAR: I'm sorry, Mr. Vick, you are excused. Thank you for your patience.

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STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk and Administrative Services, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 16th day of November, 2006.

Jane Faurot

JANE FAUROT, RPR
Official FPSC Hearings Reporter
FPSC Division of Commission Clerk and
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