BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060007-EI

In the Matter of

ENVIRONMENTAL COST RECOVERY CLAUSE.
_______________________________/

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VOLUME 1

Pages 1 through 205

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

APPEARANCES:

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JOHN W. MCWHIRTER, JR., ESQUIRE, c/o McWhirter Reeves Law Firm, McWhirter Reeves, 400 North Tampa Street, Suite 2450, Tampa, Florida 33602, appearing on behalf of Florida Industrial Power Users Group.

JOHN T. BUTLER, ESQUIRE, and BRYAN ANDERSON, Florida Power & Light Company, 700 Universe Blvd., Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

HAROLD McLEAN, PUBLIC COUNSEL, CHARLIE BECK, ESQUIRE, JOE MCGLOTHLIN, ESQUIRE, and PATTY CHRISTENSEN, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison St., #812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

JOHN T. BURNETT, Progress Energy Service Co., LLC, P.O. Box 14042, St. Petersburg, Florida 33733-4042, appearing on behalf of Progress Energy Service Company, LLC.

APPEARANCES CONTINUED:

ROBERT SCHEFFEL WRIGHT, ESQUIRE, and JOHN T. LAVIA, III, ESQUIRE, Young Law Firm, 225 South Adams Street, Suite 200, Tallahassee, Florida 32301, appearing on behalf of Florida Retail Federation.

MARTHA CARTER BROWN, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Commission Staff.

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P R O C E E D I N G S

CHAIRMAN EDGAR: We will go back on the record. And we will be beginning with the 07 docket.

Ms. Brown.

MS. BROWN: Good morning, Madam Chairman. There are a few preliminary matters in the 07 docket. The first item is PEF's motion to file supplemental direct testimony of Javier Portuondo, which was filed October 27th and amended November 1st. That motion is unopposed. Staff recommends that you approve it.

CHAIRMAN EDGAR: The motion is granted.

MS. BROWN: Then, Commissioner, we now have a completely stipulated case in the environmental clause. Since the prehearing order was issued, the parties have stipulated to the admission of Gulf's Witness Martin's testimony and exhibits into the record, as well as the testimony and exhibits of FPL's Witness LaBauve, and they have been excused from attendance at the hearing along with the other witnesses whose testimony and exhibits have been stipulated.

Gulf's Witness Vick and FPL's Witness Dubin's testimony are outstanding. It's my understanding that the Commission might have questions for Witness Vick, and probably does not have questions for Witness Dubin. And in light of that, Witness Dubin's testimony can also be stipulated into the record. We will get to that in a minute.

But at this point, it probably would be helpful to know for sure if the Commissioners have questions for Witness Vick.

CHAIRMAN EDGAR: Commissioners, any questions for Witness Vick or for Witness Dubin, so that we can produce them if there are? No. No. No.

Commissioner Arriaga does have some questions for Witness Vick.

MS. BROWN: All right. Thank you, Commissioner.

The parties have stipulated, then, to the admission of all the witnesses' prefiled testimony. The witnesses are found on Page 4 of the prehearing order. And we request that the testimony of all witnesses except Witness Vick be inserted into the record as though read at this time.

CHAIRMAN EDGAR: The prefiled testimony of all witnesses as listed in the prehearing order, except for the prefiled testimony of Witness Vick, will be entered into the record as though read.

(REPORTER NOTE: Page 8 inadvertently omitted.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Rhonda J. Martin
Docket No. 060007-EI
Date of Filing: August 4, 2006

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

A. My name is Rhonda Martin. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1994 with a Bachelor of Arts Degree in Accounting. I am also a licensed Certified Public Accountant and a member of the Florida Institute of Certified Public Accountants. I joined Gulf Power in 1994 as an Accountant. Prior to assuming my current position, I have held various positions of increasing responsibility with Gulf as an accountant in the Accounting Services, Financial Reporting, and Corporate Accounting Departments and as Supervisor of Financial Planning. In April 2006, I joined the Rates and Regulatory Matters area.

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

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

A. Yes, I have. My exhibit consists of 8 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Ms. Martin's Exhibit consisting of 8 schedules be marked as Exhibit No. _____(RJM-2).

Q. Have you verified that to the best of your knowledge and belief the information contained in these documents is correct?

A. Yes, I have.

Q. What has Gulf calculated as the estimated true-up for the January 2006 through December 2006 period to be refunded or collected in the period January 2007 through December 2007?

A. The estimated true-up for the current period is an over-recovery of $2,874,720 as shown on Schedule 1E. This is based on six months of actual data and six months of estimated data. This amount will be added to the 2005 final true-up over-recovery amount of $1,659,043 (see Schedule 1A to my testimony filed April 3, 2006). The sum of $4,533,763 will be refunded to customers during the January 2007 through December 2007 period. The detailed calculations supporting the estimated true-up for 2006 are contained in Schedules 1E through 8E.

Q. Please describe Schedules 2E and 3E of your exhibit.

A. Schedule 2E shows the calculation of the estimated over-recovery of environmental costs for the period January 2006 through December 2006. Schedule 3E of my exhibit is the calculation of the interest provision on the over-recovery. This is the same method of calculating interest that is used in the Fuel Cost Recovery and Purchased Power Capacity Cost Recovery clauses.

Q. Please describe Schedules 4E and 5E of your exhibit.

A. Schedule 4E compares the estimated/actual O & M expenses for the period January 2006 through December 2006 with the projected O & M expenses approved by the Commission in conjunction with the November 2005 hearing. Schedule 5E shows the monthly O & M expenses by activity, along with the calculation of jurisdictional O & M expenses for the current recovery period. Per the Staff's request, emission allowance expenses and the amortization of gains on emission allowances are included with O & M expenses. Mr. Vick describes the main reasons for the expected variances in O & M expenses in his true-up testimony.

Q. Please describe Schedules 6E and 7E of your exhibit.

A. Schedule 6E for the period January 2006 through December 2006 compares the estimated/actual carrying costs related to investment with the projected amount approved in conjunction with the November 2005 hearing. The recoverable costs include the return on investment, depreciation and amortization expense, dismantlement accrual, and property taxes associated with each environmental capital project for the current recovery period. Recoverable costs also include a return on working capital associated with emission allowances. Schedule 7E provides the monthly carrying costs associated with each project, along with the calculation of the jurisdictional carrying costs. Mr. Vick describes the major variances in recoverable costs related to environmental investment for this estimated true-up period in his testimony.

Q. Please describe Schedule 8E of your exhibit.

A. Schedule 8E includes 26 pages that provide the monthly calculations of recoverable costs associated with each approved capital project for the current recovery period. As I stated earlier, these costs include return on investment, depreciation and amortization expense, dismantlement accrual, property taxes, and the return on working capital associated with emission allowances. Pages 1 through 25 of Schedule 8E show the investment and associated costs related to capital projects, while page 26 shows the investment and return related to emission allowances.

Q. What capital structure and return on equity were used to develop the rate of return used to calculate the revenue requirements?

A. Consistent with Commission policy, the capital structure used in calculating the rate of return for recovery clause purposes is based on the capital structure approved in Gulf's last completed rate case. The rate of return for the Environmental Cost Recovery Clause (ECRC) is based on the capital structure approved in Docket No. 010949-EI, Order No. PSC-02-0787-FOF-EI dated June 10, 2002. The rate of return used to calculate ECRC revenue requirements includes a return on equity of 12.0% for the period January 1, 2006 through December 31, 2006.

Q. Ms. Martin, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Rhonda J. Martin
Docket No. 060007-EI
Date of Filing: September 1, 2006

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

A. My name is Rhonda Martin. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1994 with a Bachelor of Arts Degree in Accounting. I am also a licensed Certified Public Accountant and a member of the Florida Institute of Certified Public Accountants. I joined Gulf Power in 1994 as an Accountant. Prior to assuming my current position, I have held various positions of increasing responsibility with Gulf as an accountant in the Accounting Services, Financial Reporting, and Corporate Accounting Departments and as Supervisor of Financial Planning. In April 2006, I joined the Rates and Regulatory Matters area.

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Have you previously filed testimony before this Commission in connection with Gulf's Environmental Cost Recovery Clause (ECRC)?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present both the calculation of the revenue requirements and the development of the environmental cost recovery factors for the period of 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 consists of 7 schedules, each of which were prepared under my direction, supervision, or review.

Counsel: We ask that Ms. Martin's Exhibit consisting of 7 schedules be marked as Exhibit No. ______ (RJM-3).

Q. What environmental costs is Gulf requesting for recovery through the Environmental Cost Recovery Clause?

A. As discussed in the testimony of J. O. Vick, Gulf is requesting recovery for certain environmental compliance operating expenses and capital costs that are consistent with both the decision of the Commission in Docket No. 930613-EI and with past proceedings in this ongoing recovery docket. The costs we have identified for recovery through the ECRC are not currently being recovered through base rates or any other cost recovery mechanism.

Q. How was the amount of projected O & M expenses to be recovered through the ECRC calculated?

A. Mr. Vick has provided me with projected recoverable O & M expenses for January 2007 through December 2007. Schedule 2P of my exhibit shows the calculation of the recoverable O & M expenses broken down between demand-related and energy-related expenses. Also, Schedule 2P provides the appropriate jurisdictional factors and amounts related to these expenses. All O & M expenses associated with compliance with the Clean Air Act Amendments of 1990 were considered to be energy-related, consistent with Commission Order No. PSC-94-0044-FOF-EI. The remaining expenses were broken down between demand and energy consistent with Gulf's last approved cost-of-service methodology in Docket No. 010949-EI.

Q. Please describe Schedules 3P and 4P of your exhibit.

A. Schedule 3P summarizes the monthly recoverable revenue requirements associated with each capital investment project for the recovery period. Schedule 4P shows the detailed calculation of the revenue requirements associated with each investment project. These schedules also include the calculation of the jurisdictional amount of recoverable revenue requirements. Mr. Vick has provided me with the expenditures, clearings, retirements, salvage, and cost of removal related to each capital project and the monthly costs for emission allowances. From that information, I calculated Plant-in-Service and Construction Work In Progress-Non Interest Bearing. Depreciation, amortization and dismantlement expense and the associated accumulated depreciation balances were calculated based on Gulf's approved depreciation rates, amortization periods, and dismantlement accruals. The capital projects identified for recovery through the ECRC are those environmental projects which were not included in the approved June 2002 through May 2003 test year on which present base rates were set.

Q. How was the amount of Property Taxes to be recovered through the ECRC derived?

A. Property taxes were calculated by applying the applicable tax rate to taxable investment. In Florida, pollution control facilities are taxed based only on their salvage value. For the recoverable environmental investment located in Florida, the amount of property taxes is estimated to be $0. In Mississippi, there is no such reduction in property taxes for pollution control facilities. Therefore, property taxes related to recoverable environmental investment at Plant Daniel are calculated by applying the applicable millage rate to the assessed value of the property.

Q. What capital structure and return on equity were used to develop the rate of return used to calculate the revenue requirements?

A. The rate of return used is based on the capital structure approved in Gulf's last rate case, Docket No. 010949-EI, Order No. PSC-02-0787-FOF-EI, dated June 10, 2002. This rate of return incorporates a return on equity of 12.0 percent.

Q. How was the breakdown between demand-related and energy-related investment costs determined?

A. The investment costs associated with compliance with the Clean Air Act Amendments of 1990 (CAAA) were considered to be energy-related, consistent with Commission Order No. PSC-94-0044-FOF-EI, dated January 12, 1994 in Docket No. 930613-EI. The remaining investment costs of environmental compliance not associated with the CAAA were allocated 12/13th based on demand and 1/13th based on energy, consistent with Gulf's last cost-of-service study. The calculation of this breakdown is shown on Schedule 4P and summarized on Schedule 3P.

Q. What is the total amount of projected recoverable costs related to the period January 2007 through December 2007?

A. The total projected jurisdictional recoverable costs for the period January 2007 through December 2007 is $48,178,803 as shown on line 1c of Schedule 1P. This includes costs related to O & M activities of $12,797,628 and costs related to capital projects of $35,381,175 as shown on lines 1a and 1b of Schedule 1P.

Q. What is the total recoverable revenue requirement to be recovered in the projection period January 2007 through December 2007 and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $43,676,464 for the period January 2007 through December 2007 as shown on line 5 of Schedule 1P. This amount includes the recoverable costs related to the projection period and the total true-up cost of $4,533,763 to be refunded. Schedule 1P also summarizes the energy and demand components of the requested revenue requirement. I allocated these amounts to rate class using the appropriate energy and demand allocators as shown on Schedules 6P and 7P.

Q. How were the allocation factors calculated for use in the Environmental Cost Recovery Clause?

A. The demand allocation factors used in the ECRC were calculated using the 2003 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The energy allocation factors were calculated based on projected KWH sales for the period adjusted for losses. The calculation of the allocation factors for the period is shown in columns 1 through 9 on Schedule 6P.

Q. How were these factors applied to allocate the requested recovery amount properly to the rate classes?

A. As I described earlier in my testimony, Schedule 1P summarizes the energy and demand portions of the total requested revenue requirement. The energy-related recoverable revenue requirement of $38,301,544 for the period January 2007 through December 2007 was allocated using the energy allocator, as shown in column 3 on Schedule 7P. The demand-related recoverable revenue requirement of $5,374,920 for the period January 2007 through December 2007 was allocated using the demand allocator, as shown in column 4 on Schedule 7P. The energy-related and demand-related recoverable revenue requirements are added together to derive the total amount assigned to each rate class, as shown in column 5.

Q. What is the monthly amount related to environmental costs recovered through this factor that will be included on a residential customer's bill for 1,000 kwh?

A. The environmental costs recovered through the clause from the residential customer who uses 1,000 kwh will be $3.87 monthly for the period January 2007 through December 2007.

Q. When does Gulf propose to collect its environmental cost recovery charges?

A. The factors will be effective beginning with Cycle 1 billings in January 2007 and will continue through the last billing cycle of December 2007.

Q. Ms. Martin, does this conclude your testimony?

A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

Environmental Cost Recovery Clause
Final True-Up for Period
January through December, 2005

DIRECT TESTIMONY OF
JAVIER PORTUONDO

March 31, 2006

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is Post Office Box 1551, Raleigh, NC 27601.

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

A. I am employed by Progress Energy Service Company, LLC as Director of Regulatory Planning.

Q. Have your duties and responsibilities remained the same since you last testified in this proceeding?

A. Yes, with respect to Florida. I have also taken on the same responsibilities with respect to North Carolina.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recovery Clause (ECRC)?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval, Progress Energy Florida's (PEF's) Actual True-up costs associated with Environmental Compliance activities for the period January 2005 through December 2005.

Q. Are you sponsoring any exhibits in support of your testimony?

A. Yes. I am sponsoring Exhibit No.__ JP-1, which consists of eight forms. Form 42-1A reflects the final true-up for the period January 2005 through December 2005. Form 42-2A reflects the final true-up calculation for the period. Form 42-3A reflects the calculation of the Interest Provision for the period. Form 42-4A reflects the calculation of variances between actual and estimated/actual costs for O&M activities. Form 42-5A presents a summary of actual monthly costs for the period of O&M activities. Form 42-6A reflects the calculation of variances between actual and estimated/actual costs for Capital Investment Projects. Form 42-7A presents a summary of actual monthly costs for the period for Capital Investment Projects. Form 42-8A, pages 1 through 10, consist of the calculation of depreciation expense and return on capital investment for each project that is being recovered through the ECRC.

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

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

Q. What is the final true-up amount for which PEF is requesting for the period January 2005 through December 2005?

A. PEF is requesting approval of an under-recovery amount of $12,159,477 for the calendar period ending December 31, 2005. This amount is shown on Form 42-1A, Line 1.

Q. What is the net true-up amount PEF 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 next projection period?

A. PEF has calculated and is requesting approval of an under-recovery amount of $237,170 reflected on Line 3 of Form 42-1A, as the adjusted net true-up amount for the January 2005 through December 2005 period. This amount is the difference between the actual under-recovery amount of $12,159,477 and the actual/estimated under-recovery of $11,922,307, as approved in Order PSC-05-1251-FOF-EI, for the period of January 2005 through December 2005.

Q. Are all costs listed in Forms 42-1A through 42-8A attributable to environmental compliance projects approved by the Commission?

A. Yes, they are.

Q. How did actual O&M expenditures for January 2005 through December 2005 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits?

A. Form 42-4A shows that total O&M project costs were $716,447 or 1.8% higher than projected. Following are variance explanations for those O&M projects with significant variances. Individual project variances are provided on Form 42-4A.

O&M Project Variances

1. **Substation Environmental Investigation, Remediation, and Pollution Prevention (Project No. 1):** Project expenditures were $123,604 or 10.2% less than projected. This variance is primarily attributable to a change in the 2005 workplan as directed by the Florida Department of Environmental Protection (FDEP). Instead of remediating 66 substations as originally forecasted, PEF focused on the 12 remediations that had been identified as high range sites. PEF completed remediation on six of the 12 active substation sites during 2005. Initial remediation activities were also started on the remaining six substation sites; however, completion of the work will be carried over into the 2006 workplan.

2. **Pipeline Integrity Management Program (Project No. 3a):** The Pipeline Integrity Management (PIM) O&M project expenditures were $551,210 or

43.6% lower than projected. The majority of the variance is being driven by the following: (1) The budget for the risk assessment was developed using historical averages for work completion; however, the actual number of repairs in 2005 were far less than what we had historically completed and (2) PEF completed a survey to address any inadequate cover areas found on the pipeline. When developing the budget for this program, PEF assumed that the work to be completed would be in wet ground condition areas, which is far more costly. The ground conditions for the work that PEF actually completed were better than originally anticipated; therefore costs were reduced.

3. **SO2 Emissions Allowances (Project No. 5):** Project expenditures were $1,262,331 or 4.2% higher than projected. This variance is primarily attributable to a true-up adjustment made in the fourth quarter of 2005 to correct emission allowance expenses. The adjustment was made to ensure that PEF's inventories of emission allowances agreed to the balance that the U.S. Environmental Protection Agency (EPA) has on record.

4. **Phase II Cooling Water Intake (Project No. 6):** Project expenditures were $171,153 or 65.1% higher than projected. The variance is attributable to contract labor costs to perform field studies. These costs were higher than originally projected because the labor required to complete the work was greater than anticipated. The 2005 estimated projections were calculated

just three months after the work was initiated; therefore the labor requirements had not yet been fully analyzed.

5. **Arsenic Groundwater Standard (Project No. 8):** Project expenditures were expected to be $50,000; however, work was delayed in 2005 due to continued negotiations with the FDEP. Work is expected to begin in early 2006, once PEF receives the agencies' final decision on permit renewal.

6. **Sea Turtle – Coastal Street Lighting (Project No. 9):** Project expenditures were expected to be $80,000; however, work was delayed in 2005 due to negotiations with the Florida Fish & Wildlife Conservation Commission and the local governments. This work is anticipated to begin in early 2006, after meetings with officials to establish PEF's guidelines for performing these activities.

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

A. Form 42-6A shows that total Capital Investment project costs were $6,461 or 0.2% lower than projected. Actual costs and variance by individual project are provided on Form 42-6A. Following are variance explanations for those Capital projects with significant variances. Return on Capital Investment, Depreciation and Taxes for each project for the period are provided on Form 42-8A, pages 1 through 10.

Capital Investment Project Variances:

1. **Above Ground Tank Secondary Containment (Project No. 4):** Recoverable costs were $41,657 or 18.9% lower than projected. The variance is primarily attributable to the rescheduling of individual tank upgrades to ensure system availability during the critical hurricane season. The original estimate was based on the completion of upgrades to two large tanks at the Intercession City site. To ensure generation capability during the 2005 hurricane season, only one tank and the fuel oil pipeline secondary containment at this site was completed. In addition, a small aboveground storage tank at PEF's Avon Park site which was originally scheduled in the 2005 work plan will be completed in early 2006. However, work at the University of Florida, which was originally scheduled for 2006, was completed in 2005. This will allow us to focus on the remaining work at Avon Park to be completed early 2006 and Intercession City to be completed midyear.

2. **Sea Turtle – Coastal Street Lighting (Project No. 9):** Project expenditures were expected to be $3,081; however, work was delayed in 2005 due to negotiations with the Florida Fish & Wildlife Conservation Commission and the local governments. This work is anticipated to begin in early 2006, after meetings with officials to establish PEF's guidelines for performing these activities.

3. **CAIR/CAMR – AFUDC (Project 7.3):** These capital expenditures qualify for AFUDC and therefore will not be included in the recoverable costs until the associated pollution controls are placed in service. PEF originally estimated total capital expenditures to be $2,000,000 in 2005 for preliminary engineering activity and strategy development work necessary in determining the company's integrated compliance strategy. However, actual expenditures in 2005 were $1,829,277 or 8.5% lower than projected. The variance is primarily attributable to a staffing plan change which led to a minor delay in development efforts.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JAVIER J. PORTUONDO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007

AUGUST 4, 2006

Q. Please state your name and business address.

A. My name is Javier J. Portuondo. My business address is Post Office Box 1551, Raleigh, NC 27601.

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

A. I am employed by Progress Energy Service Company, LLC, as Director of Regulatory Planning.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recovery Clause (ECRC)?

A. Yes, I have.

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, Progress Energy Florida's Estimated/Actual True-up costs associated with Environmental Compliance activities for the period January 2006 through December 2006.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. __(JP-2), which consists of PSC Forms 42-1E through 42-8E. These forms provide a summary and detail of the Estimated/Actual True-up O&M and Capital Environmental costs and revenue requirements for the period January 2006 through December 2006.

Q. What is the Estimated/Actual True-up amount for which PEF is requesting recovery for the period of January 2005 through December 2005?

A. The Estimated/Actual True-up amount for 2006 is an under-recovery, including interest, of $16,770,646 as shown in Exhibit No. __ (JP-2), Form 42-1E, Line 4. This amount will be added to the final true-up under-recovery of $237,170 for

2005 shown on Form 42-2E, Line 7-a., resulting in a net under-recovery of $17,007,817 as shown on Form 42-2E, Line 11. The detailed calculations supporting the estimated true-up for 2006 are contained in Forms 42-1E through 42-8E.

Q. Are any of the costs listed in Forms 42-1E through 42-8E attributable to Environmental Compliance projects that have not previously been approved by the Commission?

A. Yes. The costs include projected expenditures associated with the Modular Cooling Towers for which PEF is seeking approval in Docket No. 060162. A revised petition was filed on July 13, 2006 seeking approval under the ECRC Docket (originally submitted February 24, 2006). The Modular Cooling Tower Project will allow compliance with environmental permit requirements that limit the temperature of cooling water discharged from the Crystal River plant.

Q. What 2006 costs are associated with the Modular Cooling Tower Project?

A. PEF is projecting $4,564,195 in O&M and $446,353 in capital expenditures ($74,471 revenue requirements on capital investment) for 2006 associated with the Modular Cooling Tower Project.

Q. Are there any other new programs for which PEF is seeking recovery under the Environmental Cost Recovery Clause?

A. No.

Q. How do the Estimated/Actual project expenditures for January 2006 through December 2006 compare with original projections?

A. As shown on Form 42-4E, total O&M project costs are projected to be $17,223,446 or 100% higher than originally projected. Total recoverable capital investments itemized on Form 42-6E, are projected to be $706,234 or 41% lower than originally projected. Below are variance explanations for those approved O&M projects and Capital Investment Projects with significant variances. Individual project variances are provided on Forms 42-4E and 42-6E. Return on Capital Investment, Depreciation and Taxes for each project for the Estimated/Actual period are provided on Form 42-8E, pages 1 through 10.

1. Substation Environmental Investigation, Remediation, and Pollution Prevention (Project #1) - O&M

Project expenditures are estimated to be $2,436,252 or 210% higher than previously projected. This variance is primarily attributable to higher than anticipated remediation costs at the West Lake Wales substation site and a greater number of sites being remediated in 2006 than originally projected. This project is more fully discussed in Kent D. Hedrick's testimony.

2. Distribution System Environmental Investigation, Remediation, and Pollution Prevention (Project #2) - O&M

Project expenditures are estimated to be $11,799,251 or 265% higher than previously projected. This variance is primarily attributable to a higher number of sites being remediated than originally anticipated in the 2006 work plan. This project is discussed in Kent D. Hedrick's testimony.

3. Above Ground Storage Tank Secondary Containment (Project #4) - Capital

While project capital expenditures are estimated to be $46,996 higher than projected, project revenue requirements for 2006 are $52,637 (13%) lower than previously forecasted because PEF originally projected a commercial in-service which was delayed, resulting in a decrease in depreciation and tax expense for the period. This project is discussed in Patricia Q. West's testimony.

4. SO2 Emissions Allowances (Project #5) – O&M

SO2 expenses are estimated to be $942,147 or 10% lower than originally projected. This variance is being driven by lower than projected average cost and a decrease in projected tons of emissions. The decrease in tons is attributable to lower SO2 content in fuel, as well as lower projected energy requirements.

5. SO2 Emissions Allowances (Project #5) – Capital

SO2 revenue requirements on working capital balances for emission allowances are estimated to be $277,160 or 89% lower than originally projected. This variance is primarily driven by a lower inventory balance than projected due to the sale of 2.8% of the 2013 vintage allowances as required by the EPA. The sale was not included in the original 2006 projections.

6. Phase II Cooling Water Intake (Project #6) – O&M

Project expenditures are estimated to be $573,746 or 39% lower than originally forecasted. This variance is primarily attributable to reduced study work requirements and lower than projected contractor costs. This project is further discussed in Patricia Q. West's testimony.

7. CAIR/CAMR (Project #7) – Capital

Project capital expenditures are estimated to be $8.3 million lower than originally projected, resulting in revenue requirements that are estimated to be $410,698 or 91% lower than originally projected. This variance is primarily attributable to schedule delays at Anclote due to additional needed studies, offset partially by changes in the compliance strategy for the Combustion Turbine projects. This project is further discussed in Patricia Q. West's testimony.

8. Arsenic Groundwater Standard (Project #8) – O&M

Project expenditures are estimated to be $50,000 or 100% lower than originally forecasted. This variance is due to the work being postponed until 2007. We are still awaiting finalization of the FDEP permit. This project is further discussed in Patricia Q. West's testimony.

9. Sea Turtle – Coastal Street Lighting (Project #9) – Capital

Project revenue requirements are estimated to be $25,522 or 76% lower than originally forecasted. This variance is primarily attributable to a delay in the commercial in-service date. PEF originally projected a commercial in-service date of January 2006, which was delayed to October 2006, resulting in a decrease in depreciation expense for the period.

10. Underground Storage Tanks (Project #10) – Capital

While project capital expenditures are estimated to be $23,000 higher than originally projected, project revenue requirements for 2006 are estimated to be $8,418 or 43% lower than previously forecasted because PEF projected a commercial in-service date which was delayed, resulting in a decrease in depreciation and tax expense for the period. This project is further discussed in Patricia Q. West's testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JAVIER PORTUONDO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

SEPTEMBER 1, 2006

Q. Please state your name and business address.

A. My name is Javier J. Portuondo. My business address is Post Office Box 1551, Raleigh, NC 27601.

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

A. I am employed by Progress Energy Service Company, LLC as Director of Regulatory Planning.

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recovery Clause (ECRC)?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, Progress Energy Florida's calculation of the revenue requirements and its Environmental Cost Recovery (ECRC) factors for application on customer billings during the period January 2007 through December 2007. My testimony addresses the capital and operating and maintenance ("O&M") expenses associated with PEF's environmental compliance activities for the year 2007.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No.__ (JP-3), which consists of PSC Forms 42-1P through 42-7P. These forms provide a summary and detail of the projected O&M and capital environmental cost recovery factors for the period January 2007 through December 2007.

Q. What is the total recoverable revenue requirement relating to the projection period January 2007 through December 2007?

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is $53,805,782 as shown on Form 42-1P, Line 5 of my exhibit.

Q. What is the total true-up to be applied in the period January 2007 through December 2007?

A. The total true-up applicable for this period is an under-recovery of $17,007,817. This consists of the final true-up under-recovery of $237,170 for the period from January 2005 through December 2005 and an estimated true-up under-recovery of $16,770,646 for the current period of January 2006 through December 2006. The detailed calculation supporting the estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No.__ (JP-2) filed with the Commission on August 4, 2006.

Q. Are all the costs listed in Forms 42-1P through 42-7P attributable to Environmental Compliance projects previously approved by the Commission?

A. No. PEF's 2007 ECRC projection includes one new project that has not been previously approved by the Commission. As discussed in the Estimated/Actual True-up testimony filed on August 4, 2006, PEF is seeking recovery of the Modular Cooling Tower Program (No. 11) in Docket No. 060162. The petition was originally filed on February 24, 2006 with a revised petition filed on July 13, 2006. An evidentiary hearing is being scheduled for a date still to be set.

In addition, PEF's 2007 ECRC projections includes the following projects that have been previously approved by the Commission:

The Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) Program (No. 7) was previously approved as an ECRC recoverable project in Order No. PSC-05-1251-FOF-EI. As requested, PEF's Integrated Clean Air Compliance Plan was submitted on March 31, 2006 under this docket.

The Substation and Distribution System O&M programs (Nos. 1 and 2) were previously approved by the Commission in Order No. PSC-02-1735-FOF-EI.

The Pipeline Integrity Management Program (No. 3) and the Above Ground Tank Secondary Containment Program (No. 4) were previously approved in Order No. PSC-03-1230-PCO-EI.

The recovery of SO_2 Emission Allowances (No. 5) was previously approved in Order No. PSC-95-0450-FOF-EI; however, the costs were moved to the ECRC Docket from Docket 030001 beginning January 1, 2004 at the request of Staff to be consistent with the other Florida IOUs.

The Phase II Cooling Water Intake 316(b) Program (No. 6) was previously approved in Order No. PSC-04-0990-PAA-EI.

The Sea Turtle Lighting Program (No. 9), the Arsenic Groundwater Standard Program (No. 8), and the Underground Storage Tanks Program (No. 10) were previously approved in Order No. PSC-05-1251-FOF-EI.

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

A. Yes. Form 42-2P contained in my exhibit summarizes the recoverable O&M cost estimates for these projects in the amount of $35,609,852.

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

A. Yes. Form 42-3P contained in my exhibit, summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 10, shows the calculations of these costs that result in recoverable jurisdictional capital costs of $1,149,402.

Q. Have you prepared schedules providing the description and progress reports for all environmental compliance activities and projects?

A. Yes. Form 42-5P, pages 1 through 11, contained in my exhibit provides each project description and progress, as well as the projected recoverable cost estimates.

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

A. The total jurisdictional capital and O&M costs of $36,759,254 to be recovered through the ECRC, are calculated on Form 42-1P, contained in my exhibit.

Q. Please describe how the proposed ECRC factors were developed.

A. The ECRC factors were calculated as shown on Forms 42-6P and 42-7P contained in Exhibit No.__ (JP-3). 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 calculated by determining the percentage each rate class contributes to total kilowatt-hour sales and then adjusted for losses for each rate class. This information was obtained from Progress Energy Florida's July 2006 load research study. Form 42-7P presents the calculation of the proposed ECRC billing factors by rate class.

Q. What are Progress Energy Florida's proposed 2007 ECRC billing factors by the various rate classes and delivery voltages?

A. The computation of Progress Energy Florida's proposed ECRC factors for customer billings in 2007 is shown on Form 42-7P, contained in Exhibit No. (JP-3). In summary, these factors are as follows:

RATE CLASS	ECRC FACTORS
Residential	0.153 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.137 cents/kWh
@ Primary Voltage	0.136 cents/kWh
@ Transmission Voltage	0.134 cents/kWh
General Service 100% Load Factor	0.088 cents/kWh

General Service Demand	
@ Secondary Voltage	0.111 cents/kWh
@ Primary Voltage	0.110 cents/kWh
@ Transmission Voltage	0.109 cents/kWh
Curtailable	
@ Secondary Voltage	0.107 cents/kWh
@ Primary Voltage	0.106 cents/kWh
@ Transmission Voltage	0.105 cents/kWh
Interruptible	
@ Secondary Voltage	0.089 cents/kWh
@ Primary Voltage	0.088 cents/kWh
@ Transmission Voltage	0.087 cents/kWh
Lighting	0.111 cents/kWh

Q. When is Progress Energy Florida requesting that the proposed ECRC billing factors be made effective?

A. PEF is requesting that its proposed ECRC billing factors be made effective with the first bill group for January 2007 and will continue through the last bill group for December 2007.

Q. Please summarize your testimony.

A. My testimony supports the approval of an average environmental billing factor of 0.132 cents per kWh which includes projected capital and O&M revenue requirements of $36,759,254 associated with a total of 11 environmental projects and a true-up under-recovery provision of $17,007,817. My testimony also demonstrates that the projected environmental expenditures for 2007 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL DIRECT TESTIMONY OF

JAVIER PORTUONDO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

OCTOBER 27, 2006

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is Post Office Box 1551, Raleigh, NC 27601.

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

A. I am employed by Progress Energy Service Company, LLC as Director of Regulatory Planning.

Q. Have you previously filed testimony before this Commission in this docket?

A. Yes, I have

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my testimony is to advise the Commission of anticipated increases in the costs of PEF's plan for implementing the Clean Air Regulatory Program originally approved in Order No. PSC-05-0998-PAA-EI. PEF's integrated compliance plan and the analyses that led to its development are explained in the Report entitled "Progress Energy Florida Integrated Clean Air Compliance Plan" ("Clean Air Report") provided as Exhibit DJR-1 to Mr. Roeder's pre-filed testimony.

Q. Why does PEF anticipate increased costs for its compliance plan?

A. As the Company moves closer to the implementation of key air pollution projects at Crystal River Units 4 and 5, recent negotiations indicate that costs for these major construction programs may increase by as much as 30 percent. Primary contributors to the cost increases are continued price increases in commodities, equipment and labor. PEF is continuing to negotiate with contractors to secure the lowest costs possible without jeopardizing project schedules necessary to achieve compliance within prescribed deadlines.

Q. Does PEF plan to change its compliance plan in light of the anticipated cost increases?

A. No. Costs for all of the alternative strategies that PEF analyzed are expected to increase for the same reasons that the costs of PEF's selected strategy are expected to increase. PEF will continue to carefully monitor project costs and adjust its strategy to assure compliance with all applicable regulations in a cost-effective and prudent manner.

Q. Will PEF continue to keep the Commission and other parties informed about the implementation of the Clean Air Regulatory Program?

A. Yes. PEF will arrange meetings with Staff and any parties to this docket who wish to attend to provide updates on PEF's implementation of the program. These meetings will be arranged to ensure that the other parties will have the opportunity to fully investigate PEF's compliance activities and costs.

Q. What effect will the anticipated increased costs have on the 2007 ECRC factors?

A. The anticipated increased costs will have no bearing on the 2007 ECRC factors because projected costs for the Crystal River projects in 2007 are all accruing AFUDC and will not affect customer rates until they are declared commercially in-service.

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL DIRECT TESTIMONY OF

JAVIER PORTUONDO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

AMENDED - NOVEMBER 1, 2006

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is Post Office Box 1551, Raleigh, NC 27601.

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

A. I am employed by Progress Energy Service Company, LLC as Director of Regulatory Planning.

Q. Have you previously filed testimony before this Commission in this docket?

A. Yes, I have

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my testimony is to advise the Commission of anticipated increases in the costs of PEF's integrated plan for complying with the regulatory requirements of the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). PEF's integrated compliance plan and the analyses that led to its development are explained in the Report entitled "Progress Energy Florida Integrated Clean Air Compliance Plan" ("Clean Air Report") provided as Exhibit DJR-1 to Mr. Roeder's pre-filed testimony.

Q. Why does PEF anticipate increased costs for its compliance plan?

A. As the Company moves closer to the implementation of key air pollution projects at Crystal River Units 4 and 5, recent negotiations indicate that costs for these major construction programs may increase by as much as 30 percent. Primary contributors to the cost increases are continued price increases in commodities, equipment and labor. PEF is continuing to negotiate with contractors to secure the lowest costs possible without jeopardizing project schedules necessary to achieve compliance within prescribed deadlines.

Q. Does PEF plan to change its compliance plan in light of the anticipated cost increases?

A. No. Costs for all of the alternative strategies that PEF analyzed are expected to increase for the same reasons that the costs of PEF's selected strategy are expected to increase. PEF will continue to carefully monitor project costs and adjust its strategy to assure compliance with all applicable regulations in a cost-effective and prudent manner.

Q. Will PEF continue to keep the Commission and other parties informed about the implementation of the Clean Air Regulatory Program?

A. Yes. PEF will arrange meetings with Staff and any parties to this docket who wish to attend to provide updates on PEF's implementation of the program. These meetings will be arranged to ensure that the other parties will have the opportunity to fully investigate PEF's compliance activities and costs.

Q. What effect will the anticipated increased costs have on the 2007 ECRC factors?

A. The anticipated increased costs will have no bearing on the 2007 ECRC factors because projected costs for the Crystal River projects in 2007 are all accruing AFUDC and will not affect customer rates until they are declared commercially in-service.

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

KENT D. HEDRICK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

August 4, 2006

Q. Please state your name and business address.

A. My name is Kent D. Hedrick. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Progress Energy Carolina as Manager, Performance Support.

Q. What is the scope of your duties?

A. Currently, my responsibilities include managing process technology systems, both existing and emerging, for the Energy Delivery Florida organization.

Q. Please describe your educational background and professional experience.

A. I received a Bachelors of Science degree in Environmental Engineering from the University of Florida. In addition, I am a registered professional engineer in the State of Florida. Currently I hold the position of Manager, Performance

Support. Before then, I held several environmental management positions with the Company.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recovery Clause?

A. Yes, I have.

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. No. I have moved into a new position managing process technology systems, both existing and emerging, for the Energy Delivery Florida organization. My environmental responsibilities are being transitioned to the Supervisor, System Integrity and Environmental Services.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between the Estimated/Actual project expenditures versus the original cost projections for environmental compliance costs associated with PEF's Substation and Distribution System Environmental Investigation, Remediation, and Pollution Prevention Programs for the period January 2006 through December 2006.

Q. Are you sponsoring any exhibits to your testimony?

A. No.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Substation System Program for the period January 2006 to December 2006.

A. Project expenditures for the Substation System Program are estimated to be $2,436,252 higher than originally projected. This is primarily attributable to: 1) higher than anticipated costs to remediate the West Lake Wales substation and 2) acceleration of remediations into 2006. The magnitude of contamination at Progress Energy's West Lake Wales substation is significantly larger than projected due to the extent of subsurface contamination that was not evident during the original environmental inspection. To date, remediation costs at this site have exceeded $600,000 and further remediation work will be necessary pending discussions with the FDEP. In addition, the number of substation remediations will exceed the original projection because of the completion of the target number of forecasted sites by mid-year 2006. The FDEP requires Progress Energy to continue remediating substations until this phase of the program is complete.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Distribution System Program for the period January 2006 to December 2006.

A. Project expenditures for the Distribution System Program are estimated to be $11,799,251 higher than originally projected. This increase is attributable to the projected completion of a greater number of sites than originally planned. The work plan for remediations increased due to the fact that a greater number of sites have been identified as requiring remediation

Q. Are there any new environmental programs that fall within your responsibilities for which PEF is seeking recovery in this docket?

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

KENT D. HEDRICK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

SEPTEMBER 1, 2006

Q. Please state your name and business address,

A. My name is Kent D. Hedrick. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Progress Energy Carolina as Manager, Performance Support.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recovery Clause?

A. Yes, I have.

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes. Currently, my responsibilities include managing process technology systems, both existing and emerging, for the Energy Delivery Florida organization. My environmental responsibilities are being transitioned to the Supervisor, System Integrity and Environmental Services.

Q. What is the purpose of your testimony?

A. My testimony provides estimates of the costs that will be incurred in the year 2007 for PEF's Substation and Distribution System Investigation, Remediation and Pollution Prevention Programs (Projects #1 and #2, respectively), which were previously approved in PSC Order No. PSC-02-1735-FOF-EI, and for PEF's Sea Turtle/Street Lighting Program (Project #9) which was previously approved in PSC Order No. PSC-05-1251-FOF-EI.

Q. What costs do you expect to incur in 2007 in connection with the Substation System Investigation, Remediation and Pollution Prevention Program (Project #1)?

A. For 2007, we estimate Progress Energy will incur total O&M expenditures of $4,347,620 in remediation costs for the Substation System Investigation, Remediation and Pollution Prevention Program. This amount includes estimated costs for remediation activities at 84 substation sites that have already been identified as requiring remediation.

Q. What steps is the Company taking to ensure that the level of expenditures for the Substation System Program is reasonable and prudent?

A. The Company works annually with the FDEP to determine the sites that will be remediated to ensure compliance with DEP criteria and provides quarterly reports to the FDEP on progress made in remediating substation sites. To ensure the level of expenditures is reasonable and prudent, the Company selected contractors through a competitive bidding process and reviews invoices for accuracy.

Q. What costs do you expect to incur in 2007 in connection with the Distribution System Investigation, Remediation and Pollution Prevention Program (Project #2)?

A. For 2007 we estimate total O&M expenditures of $15,991,000 for the Distribution System Investigation, Remediation and Pollution Prevention Program to perform remediation activities at 1,531 sites. This estimate assumes 341 3-phase transformer sites at an average cost of $14,500 per site; 1,190 single-phase transformer sites at an average cost of $8,500 per site; as well as program management costs.

Q. What steps is the Company taking to ensure that the level of expenditures for the Distribution System program is reasonable and prudent?

A. To ensure the level of expenditures is reasonable and prudent, the Company selected contractors through a competitive bidding process and frequently reviews invoices for accuracy and proper documentation. In addition, the Company closely monitors remediation work, performs sample testing of inspection results, and provides quarterly reports to the FDEP on progress made in remediating distribution sites.

Q. What costs do you expect to incur in 2007 in connection with the Sea Turtle/Street Lighting Program (Project #9)?

A. For 2007, the projected expenses for the Sea Turtle/Street Lighting Program are approximately $625,000. This amount includes $475,000 in O&M costs and $150,000 in capital expenditures to satisfy the new criteria that local governments are applying to ensure compliance with sea turtle ordinances in Franklin and Gulf Counties and the City of Mexico Beach. Capital and O&M cost estimates are based on modifications and/or replacement of approximately 1,200 lighting fixtures. The cost projections assume that half of these lighting fixtures can be modified to meet the new criteria and the other half will have to be replaced with another type of lighting to meet the new criteria. Modification options include adding lenses, shielding, adjusting fixture height and/or buffering. Replacement with new technology lighting will occur where it is demonstrated that compliance with the new criteria cannot be achieved through modifications. An average unit cost of $250 was used to estimate the O&M and capital budget. The estimated O&M projections also include costs for continued monitoring of the effectiveness of these retrofits, mapping current and proposed coastal lighting locations for compliance determinations, as well as research costs associated with developing lighting technology to use where required high pressure sodium lighting replacement is needed. Compliance plans are still under review and may change based on the outcome of discussions with regulatory agencies to determine the most cost-effective and appropriate compliance measures for specific sites.

Q. What steps is the Company taking to ensure that the level of expenditures for the Sea Turtle/Street Lighting Program is reasonable and prudent?

A. Progress Energy continues to work with local governments and appropriate agencies to develop compliance plans that allow flexibility to make only those modifications that are necessary to achieve compliance. Case-by-case evaluation of each streetlight requiring modification will occur to ensure that only those activities necessary to achieve compliance are performed in a reasonable and prudent manner. In addition, Progress Energy will evaluate emerging technologies and incorporate their use where reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>PATRICIA Q. WEST</u>

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

AUGUST 4, 2006

Q. Please state your name and business address.

A. My name is Patricia Q. West. My business address is 100 Central Avenue, St. Petersburg, Florida, 33701.

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

A. I am employed by the Environmental Services Section of Progress Energy Service Company, LLC ("Progress Energy" or "Company") as Manager of Competitive Commercial Operations / Energy Supply Florida. In that position I have responsibility to ensure support for the implementation of compliance strategies pertaining to regulatory requirements for power generation facilities in Florida.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recovery Clause?

A. Yes, I have.

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between the Estimated/Actual project expenditures and the original cost projections for environmental compliance costs associated with PEF's Above Ground Storage Tank Secondary Containment Program, Underground Storage Tank Program, Phase II Cooling Water Intake Program, Arsenic Groundwater Standard Program, and the Integrated Air Compliance Program for the new Clean Air Interstate Rule (CAIR) and a new Clean Air Mercury Rule (CAMR) for the period January 2006 through December 2006.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Above Ground Storage Tank Secondary Containment Program for the period January 2006 to December 2006.

A. PEF is projecting capital expenditures to be $46,996 higher for this program than originally projected. This variance is primarily attributable to unanticipated costs associated with transferring fuel out of the tanks in order to enable the work to be performed, as well as higher contractor costs.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Phase II Cooling Water Intake Program for the period January 2006 to December 2006.

A. PEF is projecting O&M expenditures to be $573,746 lower than previously projected for this program. The variance is primarily attributable to reduced study work requirements at Crystal River and Suwannee, as well as reduced contract study costs for Suwannee due to a change in the staff complement. The original projection included costs for both entrainment and impingement studies at Crystal River and Suwannee. The results of additional assessments at those sites have indicated that PEF will be able to demonstrate compliance with the entrainment standards, which will eliminate the need for entrainment studies.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) for the period January 2006 to December 2006?

A. For the Crystal River and Anclote projects in 2006, PEF anticipates spending approximately $18 million capital dollars less than originally projected excluding AFUDC. The $9 million Crystal River variance is the result of continuing project evaluations and schedule changes. The projections were originally developed with the Unit 4 and Unit 5 projects being performed in a sequential manner; however, as the projects have progressed, it has become evident that performing the projects in parallel will be more efficient for purchasing materials and for sequencing construction. The Crystal River project has no bearing on the ECRC recoverable balance because it is accruing AFUDC. The $9 million Anclote Unit 1 variance is attributable to the deferral of installing NOx reduction equipment pending additional study work that is necessary.

The Combustion Turbine (CT) projects are expected to exceed the original capital expenditure projection by $703,246 due to changes in the compliance strategy. The original projection included the installation of sample ports in 2006; however, in order to assure compliance with the 2009 Federal deadline, PEF has decided to accelerate into 2006 the design and procurement of required meters and controls, which were originally scheduled for 2007.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Arsenic Groundwater Standard Program for the period January 2006 to December 2006.

A. PEF projects O&M expenditures to be $50,000 lower for this program than originally projected. PEF cannot proceed with work without DEP approval, which is anticipated to be received through the issuance of the final permit by December 2006. As a result, work has been deferred until 2007.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Underground Storage Tank Program for the period January 2006 to December 2006.

A. PEF is projecting capital expenditures to be $23,000 higher than originally projected for this program. The variance is primarily attributable to higher than anticipated contractor costs for work being performed at Crystal River.

Q. **Does this conclude your testimony?**

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

SEPTEMBER 1, 2006

Q. Please state your name and business address.

A. My name is Patricia Q. West. My business address is 100 Central Avenue, St. Petersburg, Florida, 33701.

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

A. I am employed by the Environmental Services Section of Progress Energy Service Company, LLC. ("Progress Energy" or "Company") as Manager of Competitive Commercial Operations / Energy Supply Florida. In that position I have responsibility to ensure support for the implementation of compliance strategies pertaining to regulatory requirements for power generation facilities in Florida.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recovery Clause?

A. Yes, I have.

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. This testimony provides estimates of the costs that will be incurred in the year 2007 for environmental programs that fall within the scope of my responsibilities to support Progress Energy's power operations group. These programs include the Pipeline Integrity Management Program (Project 3), Aboveground Storage Tanks Secondary Containment Program (Project 4), Phase II Cooling Water Intake 316(b) Program (Project 6), the Integrated Air Compliance Program for the new Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) (Project 7), Arsenic Groundwater Standard Program (Project 8), Underground Storage Tank Program (Project 10), as well as the Modular Cooling Tower Program (Project 11) for which the Company requested approval this year under Docket No. 060162-EI.

Q. Please identify the additional programs within your responsibility for which the Company is seeking approval.

A. In February 2006, the Company filed a petition in Docket No. 060162-EI requesting approval for the Modular Cooling Tower Program (Project 11). A revised petition was filed on July 13, 2006 seeking approval under this docket. The Modular Cooling Tower Program will allow compliance with environmental permit requirements that limit the temperature of cooling water discharged from the Crystal River plant.

Q. What costs do you expect to incur in 2007 in connection with the Pipeline Integrity Management Program (Project 3)?

A. For 2007, we estimate that Progress Energy will incur a total $277,000 in O&M and $50,000 in capital expenditures to comply with the Pipeline Integrity Management ("PIM") regulations (49 CFR Part 195) and the Company's PIM Plan. PEF is projecting to spend $237,000 in O&M on PIM Program Administration, which includes program auditing, risk model updating, GIS development, and procedure development. In addition, we are projecting O&M costs of $40,000 and capital expenditures of $50,000 for integrity risk reduction projects. The integrity risk reduction projects include items such as: corrosion repairs, inadequate cover restoration, and pressure control upgrades.

Q. What steps is the Company taking to ensure that the level of expenditures for the Pipeline Integrity Management Program is reasonable and prudent?

A. As additional work is identified to comply with the PIM regulations, Progress Energy Florida will identify qualified suppliers of the necessary services through a competitive bidding process.

Q. What costs do you expect to incur in 2007 in connection with the Aboveground Storage Tank Secondary Containment Program (Project 4)?

A. Progress Energy is projecting to spend $1,043,360 in capital expenditures in 2007. These costs are for the double-bottoming of storage tanks and installation of some double-walled piping at the Suwannee and Bayboro Combustion Turbine sites.

Q. What steps is the Company taking to ensure that the level of expenditures for the Aboveground Storage Tank Secondary Containment Program is reasonable and prudent?

A. As additional work is identified to comply with the Aboveground Storage Tank regulations, Progress Energy Florida will identify qualified suppliers of the necessary services through a competitive bidding process.

Q. What costs do you expect to incur in 2007 in connection with the Phase II Cooling Water Intake Program (Project 6)?

A. Progress Energy is projecting to spend $1,409,057 in O&M expenditures in 2007. These costs are associated with the Comprehensive Demonstration Studies (CDS) that will be performed at the Anclote, Crystal River, and Suwannee sites. The scope of the CDS work includes: technical evaluation of study results, as well as engineering studies that will consider design, construction, installation and operational issues associated with selected compliance options.

Q. What steps is the Company taking to ensure that the level of expenditures for the Phase II Cooling Water Intake Program is reasonable and prudent?

A. As additional work is identified to comply with the Phase II Cooling Water Intake Program, Progress Energy Florida will identify qualified suppliers of the necessary services through a competitive bidding process.

Q. What costs do you expect to incur in 2007 in connection with the CAIR / CAMR Program (Project 7)?

A. PEF is projecting to spend approximately $197 Million on CAIR/CAMR compliance projects at the Crystal River and Anclote generating facilities in the year 2007. The $196 Million projected to be spent on Crystal River activities has no bearing on the ECRC recoverable balance because it is accruing AFUDC. These projects include the following:

- Anclote Unit 1 NOx Reduction Projects: Additional analysis of NOx reduction technologies is required to determine which technologies are appropriate for the Anclote units. This analysis is currently in progress, with approximately $127,000 currently budgeted to be spent in 2007 for this purpose. Installation of any technologies at Anclote Unit 1 would be expected to occur in the fall of 2008.
- Crystal River Units 4 and 5 SCR System: PEF is projecting to spend approximately $70 Million on Crystal River Unit 4 and $24 Million on Crystal River Unit 5. We will complete the design and engineering of the SCR system and its auxiliary systems. In addition, we will continue with procurement of materials and equipment and commence construction of the SCR with an expected

completion date of November 2008 for Crystal River Unit 4 and May 2009 for Crystal River Unit 5.

- Crystal River Units 4 and 5 FGD System: PEF is projecting to spend approximately $28 Million on Crystal River Unit 4 and $73 Million on Crystal River Unit 5. We will complete the design and engineering of the FGD system, its auxiliary systems, and the plant infrastructure modifications necessary to incorporate FGD operations into the existing plant. In addition, we will continue with procurement of materials and equipment, and commence construction of the FGD system and the infrastructure modifications with an expected completion date of November 2009 for Crystal River Unit 4 and May 2009 for Crystal River Unit 5.

Other projects that are required for compliance with these new rules include the following:

- Combustion Turbine Projects: To be in compliance with CAIR 44 emission sources associated with 31 of PEF's combustion turbine units must install new Predictive Emission Monitoring Systems. In 2007, computer software upgrades will be performed, along with required testing and certification of the new systems. The capital cost for this work is estimated to be $1,000,944.

- Mercury Continuous Emissions Monitoring Systems (CEMS): PEF is projecting to spend $250,000 in O&M to install mercury monitoring ports on the stacks of Crystal River Units 1, 2, and 5.

These ports are necessary for the future installation of the mercury monitoring probes. The work will be performed during planned outages.

Q. What steps is the Company taking to ensure that the level of expenditures for the CAIR / CAMR Program is reasonable and prudent?

A. An initial screening of technology and fuel choice options was performed by the Company's Construction Department when the preliminary CAIR and CAMR rules were announced in 2004. Subsequent to this initial screening and the March 2005 issuance of the final CAIR and CAMR, a more detailed series of analyses were performed and a plan was developed (the "Progress Energy Florida Integrated Clean Air Compliance Plan", submitted on March 31, 2006) to demonstrate that the selected technologies and fuel choice options were the most cost effective ways for PEF to comply with the CAIR and CAMR at Crystal River and Anclote.

With the recent increase in activity in the construction of both air pollution control equipment as the result of CAIR and CAMR and in new plant development, PEF recognized that along with increases in basic materials such as steel and concrete, construction costs were increasing rapidly throughout the industry. In order to reduce the risk of construction cost increases during the duration of these projects, PEF has initiated a competitive bidding process to establish an Engineering, Procurement and Construction ("EPC") contract with a major construction firm. This contract is being developed to include the entire scope of work for the FGD and SCR systems for procuring all equipment that has not already been purchased and for providing construction services (labor, schedule coordination, project management, etc.) for the projects at a fixed price.

As various design options are developed, they are evaluated using an internally developed cost evaluation program, which takes into account capital costs, operations and maintenance costs, fuel costs, capacity changes, availability changes, etc. to evaluate the least cost option with the best Net Present Value. These analyses have been performed to determine the least cost options for selecting different types of equipment and for determining the optimum layout of major equipment within the existing facility.

As additional work is identified for the combustion turbine and CEMS projects, PEF will identify qualified suppliers of the necessary services through the competitive bidding process. Bulk procurement will also be utilized as appropriate.

Q. What costs do you expect to incur in 2007 in connection with the Arsenic Groundwater Standard Program (Project 8)?

A. Progress Energy is currently working with the Florida Department of Environmental Protection to renew the industrial wastewater permit for the Crystal River Energy Complex. Based upon preliminary discussions, PEF is projecting O&M expenditures of $77,669. These costs will include: preparation of new a groundwater monitoring plan, installation of new groundwater monitoring wells, as well as analytical testing of groundwater.

Q. What steps is the Company taking to ensure that the level of expenditures for the Arsenic Groundwater Standard Program is reasonable and prudent?

A. As additional work is identified to comply with the new Arsenic standard, Progress Energy Florida will identify qualified suppliers of the necessary services through a competitive bidding process.

Q. What costs do you expect to incur in 2007 in connection with the Underground Storage Tanks Program (Project 10)?

A. Progress Energy is not anticipating any costs to be incurred in 2007. All projects are scheduled for completion by the end of 2006.

Q. Please describe the Modular Cooling Tower Program for which you are seeking recovery.

A. The purpose of the project is to enable PEF to comply with the permit limit on the temperature of cooling water discharges from the Crystal River plant in a manner that minimizes "de-rates" of Crystal River Units 1 and 2 (CR-1 and CR-2). A "de-rate" is a temporary reduction in the output of a generating unit. Because CR-1 and CR-2 are base-load coal units, whenever those units are de-rated PEF must replace the lost generation by using more expensive oil or gas-fired units, or by purchasing higher-cost power on the open market. The Project involves installation and operation of modular cooling towers in the summer months (mid-May through mid-September) in order to reduce the discharge canal temperature. This will enable PEF to reduce the number and extent of de-rates and thereby reduce replacement fuel and purchase power costs.

Q. What costs do you expect to incur in 2007 in connection with the Modular Cooling Tower Program (Project 11)?

A. PEF is projecting to spend approximately $3.4 million in O&M expenditures in 2007. Project costs are expected to include O&M expenses for rental fees.

Q. What steps is the Company taking to ensure that the level of expenditures for the Modular Cooling Tower Program is reasonable and prudent?

A. PEF will evaluate the prudency and cost effectiveness of the cooling towers annually as discussed more fully in Thomas Lawery's testimony.

Q. Does this conclude your testimony?

A. Yes it does.

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

Environmental Cost Recovery Clause

DIRECT TESTIMONY OF DANIEL J. ROEDER

March 31, 2006

Q. Please state your name and business address.

A. My name is Daniel J. Roeder. My business address is 410 S. Wilmington Street, Raleigh, North Carolina 27601

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

A. I am employed by Progress Energy Carolinas, Inc. (PEC), as a Project Leader in the System Resource Planning Section of the System Planning & Operations Department.

Q. What are your responsibilities in that position?

A. The System Resource Planning Section is responsible for the resource planning for both Progress Energy Florida (PEF or the Company) and PEC systems. My responsibilities include analyzing the economic and system planning implications of special projects, such as PEF's Integrated Clean Air Compliance Plan that is the subject of my testimony.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Tennessee with a B.S. in Engineering Science and Mechanics in 1980, and I obtained my M.S. in Mechanical Engineering in 1982. I have been a PEC employee since 1982 and, with the exception of a one year rotational field assignment, I have worked the entire time in the System Planning and Operations Department, performing analyses such as production costing, generation reliability, integrated resource planning, and Clean Air Act compliance. I am a registered Professional Engineer in North Carolina.

Q. Have you previously testified before the Commission?

A. Yes. I previously submitted pre-filed testimony in support of PEF's petitions for determination of need for its Hines Unit 3 and Hines Unit 4 power plants.

Q. What is the purpose of your testimony?

A. In Order No. PSC-05-0998-PAA-EI, the Commission found that costs for complying with the new Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) are eligible for recovery through the ECRC subject to PEF's demonstration that costs for specific projects are reasonable and prudent as they are submitted for recovery in the annual ECRC proceedings. The purpose of my testimony is to present PEF's Integrated Clean Air Compliance Plan, which identifies the specific compliance projects that PEF currently intends to pursue in order to comply with CAIR, CAMR and related regulations. I also will describe the Company's objectives in developing the plan, provide an overview of the Company's compliance planning process, and present the results of that process.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring Exhibit No. __ (DJR-1), a report entitled "Progress Energy Florida - Integrated Clean Air Compliance Plan" which I will refer to as the "Clean Air Report" or "Report." The Clean Air Report, which is being submitted separately with my pre-filed testimony, details the Company's Integrated Clean Air Compliance Plan and supporting analyses. For ease of reference, excerpts from the Report are attached as Exhibit Nos. __ (DJR-2) and __ (DJR-3) and __ (DJR-4) to my pre-filed testimony. Exhibit No. __ (DJR-2), which is Table 12-1 from the Report, provides a summary of five alternative compliance plans that the Company analyzed. Exhibit No. __ (DJR-3), which includes Figure 12-6, 12-7 and 12-8 from the Report, provides results of the Company's economic analysis of the five alternative plans. Exhibit No. __ (DJR-4), which includes Figure 12-9 and 12-10 from the Report, provides results of sensitivity analyses.

Q. What was your role in developing PEF's Integrated Clean Air Compliance Plan?

A. I was responsible for the development and evaluation of five alternative compliance plans, including the Integrated Clean Air Compliance Plan that the Company has chosen for implementation. I also supervised the preparation of the Clean Air Report.

Q. What were the Company's objectives in developing the Integrated Clean Air Compliance Plan?

A. The ultimate purpose of the Plan is to achieve compliance with the requirements of the new CAIR, CAMR, and Clean Air Visibility Rule (CAVR), which are discussed in Mr. Holler's pre-filed testimony and in Chapter 2 of the Clean Air Report. The Company's compliance planning process was designed to select a plan that meets all environmental requirements, manages risk, provides flexibility, and controls costs.

The first objective — **meeting environmental requirements** — is relatively straightforward. The Company takes its environmental responsibility seriously and will meet all requirements of CAIR, CAMR, and CAVR, and all other state and federal environmental regulations.

The second objective — **managing risk** — requires consideration and balancing of numerous uncertainties, including the cost of technology options, fuel and allowance markets, and the structure and type of environmental regulations.

The third objective — **providing flexibility**— refers to the ability to change direction based on new information. As plans extend into the future, the possibilities for unforeseen circumstances increase. Therefore, it is important to maintain the ability to alter course based on new information.

The final objective – **controlling costs** — is a critical factor. PEF seeks to achieve compliance using the most cost-effective plan to provide emission reductions at the lowest reasonable cost to its customers.

Q. Please briefly describe the Company's compliance planning process.

A. The compliance planning process was similar to the process PEF uses to select the Company's resource plan. The basic steps in the process are as follows:

(1) Identification of compliance options;

(2) Development of cost and operating data for all options;

(3) Technical and economic screening of all options;

(4) Development of alternative compliance plans;

(5) Evaluation of the alternative plans, including sensitivity analyses of key uncertainties; and

(6) Selection of the plan that meets the Company's objectives.

Q. How did the Company identify potential compliance options?

A. We evaluated the requirements of CAIR, CAMR, and CAVR to estimate the amount of emission reductions that PEF would need to achieve in order to comply with the new regulations. We also reviewed PEF's emissions inventory to identify which generating units could be controlled to achieve the projected amount of required emission reductions. And we identified potentially applicable emission reduction measures, including control technologies and fuel switches.

Q. What sources of cost and operating data did the Company use in evaluating the various compliance options?

A. As Mr. Holler discusses in his pre-filed testimony, the Company used a number of sources, including studies performed by engineering consultants, internal studies, equipment vendors, and experience gained from Progress Energy projects that have already been installed or are in progress to assess the cost and feasibility of various compliance options. As discussed in Chapters 8 and 9 of the Clean Air Report, the Company also conducted market studies of various coals and transportation methods and an analysis of the range of future prices for emission allowances. The results of these technical studies provided data used in the economic evaluation of the compliance options.

Q. Please explain why and how you performed the economic screening analyses.

A. Prior to developing alternative plans, the first step was to conduct screening analyses to eliminate from further consideration those sulfur dioxide (SO_2) and nitrogen oxides (NOx) compliance options that did not meet technical criteria or were not economically competitive with other options. Screening was conducted on a unit basis and on a system basis to select the most cost-effective options for all units. The end results of the screening analyses were system "supply curves" ranking emission control options based on their cost per ton of pollutant removed.

Q. Please explain how the Company developed alternative plans for consideration.

A. Based on the supply curves, we developed five alternative compliance plans (Plans A through E). The supply curves identified the cost and emission reduction characteristics associated with specific measures or controls for PEF's highest emitting units. In general, emission reduction measures were selected and included in a plan by proceeding from the least cost measure at the top of the list to higher cost measures until the cumulative reductions reached the expected number of reductions needed to comply. Chapters 11 and 12 of the Clean Air Report describe this methodology in detail.

Q. Please summarize the five alternative plans (A through E).

A. Plan A is consistent with the preliminary compliance plan that PEF developed in 2005. This plan assumes that PEF will scrub all four units at Crystal River in order to comply with both CAIR and the BART requirements of CAVR. The NOx portion of Plan A also assumes SCRs will have to be placed on all four units at Crystal River and that LNB/SOFA systems will be installed on the Anclote units for compliance with CAIR and CAVR. No dedicated mercury controls are included in this plan. The combination of wet scrubbers and SCRs on the Crystal River units would remove approximately 80 percent of the mercury emissions from the flue gas.

Plan B assumes that complying with CAIR will meet the requirements of CAVR. Thus, Crystal River Unit 1 would not be scrubbed, and instead, would continue to burn compliance coal throughout the planning period. Crystal River 1 would not be scrubbed because scrubbing that unit is projected to have a higher incremental reduction cost than scrubbing Crystal River Unit 2. Plan B includes the burning of lower sulfur oil at both Anclote units because the incremental cost of this alternative is one of the lower-cost measures for reducing SO_2 emissions. The lower sulfur oil would be used during only some years, as necessary to bring emissions below the number of allowances received each year. The NOx portion of Plan B includes SCRs at Crystal River Units 2, 4, and 5 and LNB/SOFA systems at Anclote Units 1 & 2. Although an SCR at Crystal River 1 is lower-cost than an SCR at Crystal River 2, to obtain the mercury reduction synergies of wet scrubbers and SCR systems, the SCR on Crystal River 2 was chosen instead of an SCR at Unit 1. For mercury, Plan B would require installation of a powdered activated carbon (PAC) injection system on Crystal River Unit 1 to remain compliant with CAMR through the end of 2025.

Plan C is similar to Plan B with the exception that a scrubber and SCR would be installed on Crystal River Unit 1 instead of Unit 2. Site conditions at Crystal River are such that adding controls to Crystal River Unit 2 would make it extremely difficult to install controls on Unit 1 at a later date. Therefore, adding controls on Unit 1, as assumed in this plan, would allow PEF the ability to put controls on Unit 2, if necessary, at a later date. Under this plan, Crystal River Unit 2 would burn compliance coal throughout the planning period. Because Crystal River Unit 1 is smaller than Unit 2, additional emission reductions would be needed. Therefore, Anclote Units 1 and 2 would burn lower sulfur oil beginning in 2010 and throughout the planning period. Because Plan C does not control both Crystal River Units 1 and 2, it relies on the premise that complying with CAIR will satisfy CAVR requirements. Plan C would require the addition of a PAC injection system on Crystal River Unit 2 to remain compliant with CAMR through the end of 2025.

Plan D is the first plan designed with the purchase of allowances for CAIR compliance in mind. Plan D includes wet scrubbers and SCRs on Crystal River Units 4 and 5, burning compliance coal at Units 1 and 2, and burning low sulfur oil and natural gas at Anclote Units 1 and 2 throughout the planning period, starting in 2010. LNB/SOFA controls would be installed on the Anclote units for NOx reductions. These control options are among the lowest-cost options and would provide most, but not all, of the reductions required. Unlike Plans A, B, and C, Plan D relies to some extent on purchasing allowances for CAIR compliance. Like Plans B and C, Plan D relies on the premise that compliance with CAIR will satisfy CAVR requirements. For CAMR compliance, a PAC injection system would be installed on Crystal River Unit 2 in 2017.

Plan E takes a different approach to compliance than all the other plans, in that it focuses on installing controls on Crystal River Units 1 and 2 and Anclote Unit 1 for CAVR compliance and purchasing allowances for CAIR compliance. Plan E calls for the installation of wet scrubbers and SCRs on Crystal River Units 1 and 2, as well as burning low sulfur oil and natural gas and installing LNB/SOFA controls at Anclote. Crystal River Units 4 and 5 would continue to burn 1.2 lbs

SO_2/mmBtu coal they currently burn. In Plan E the units would have PAC injection systems installed for mercury control.

Exhibit No. __ (DJR-2), which is Table 12-1 from the Clean Air Report summarizes the five alternative plans and provides the installation dates for the various measures included in each plan.

Q. How did the Company evaluate the five alternative plans?

A. As discussed in Chapter 12 of the Clean Air Report, we conducted a quantitative evaluation to determine the environmental compliance implications and economic impacts of the alternative plans. The economic analyses included sensitivity analyses to assess the potential impact of uncertainties in allowance markets and capital costs. We also conducted a qualitative evaluation of the alternative plans to assess their ability to achieve compliance while at the same time providing flexibility to adjust in response to new information or developments in the future.

Q. How did the five alternative plans compare in terms of environmental compliance?

A. Plan A would reduce emissions to levels below the number of allowances PEF expects to receive in all years except NOx emissions in 2009 and 2010. As noted above, by calling for installation of emission controls on all four Crystal River units, Plan A is consistent with the preliminary compliance plan that PEF developed in 2005, which was based on earlier projections. However, assumptions of planned new coal and nuclear unit additions have reduced the projected emissions. Therefore, under the assumptions of load growth and new generation additions made for this study, controlling emissions on all four Crystal River units will not be necessary for PEF to comply with CAIR in the long term. In addition to SO_2 and NOx, mercury emissions would be controlled through 2025, assuming reductions prior to 2018 are allowed to be banked and used after 2018. If, however, PEF is not allowed to bank mercury allowances, controls specifically designed to reduce mercury emissions would need to be added to the Crystal River units prior to 2018.

Under Plan B, PEF's SO_2 and NOx emissions more closely match the CAIR allowances, as compared to Plan A. There are years in which emissions are greater than the number of allowances; however, the analysis assumes PEF will use its bank of allowances to remain in compliance. Through 2025, PEF's reductions would be greater than required under CAIR, as evidenced by the allowance balances being greater than the projected emissions in 2025.

By adding controls to Crystal River Unit 1 instead of Unit 2 as in Plan B, Plan C would provide a better match between emissions and allowances than Plans A and B. The allowance balance at the end of the study period would be smaller because controlling Unit 1, which is smaller than Unit 2, does not reduce emissions as much as Plan B. Still, the SO_2 and NOx allowance balances at the end of 2025 would be significantly greater than projected emissions. The mercury allowance balance, on the other hand, would be only slightly higher than the projected emissions. With this plan, PEF would have the flexibility to advance the PAC injection system on Crystal River Unit 2 to an earlier year, if necessary.

As noted above, Plan D is the first plan designed with the purchase of allowances for CAIR compliance in mind. Beginning in 2015, PEF's SO_2 emissions would be greater than the number of allowances received. The SO_2 allowance bank would be depleted after 2023; thus, PEF would have to purchase approximately 15,000 allowances per year starting in 2024. PEF's NOx emissions under Plan D would be greater than or equal to the number of allowances it will receive in most of the years. Approximately 3,000 annual and 1,500 ozone season NOx allowances would need to be purchased annually starting in 2015. For mercury, the allowance balance would be only slightly above zero at the end of 2025. Under Plan D, PAC injection systems would be installed on Crystal River 2 in 2017. PEF would have the ability to add controls to Crystal River Unit 1 or advance the controls on Unit 2, if necessary.

Plan E assumes installation of SO_2 and NOx control measures only on BART-affected units (Anclote 1 and Crystal River Units 1 and 2). Under this plan, PEF's emissions would be greater than the SO_2 and NOx allowances it receives in all years. PEF would have to purchase approximately 28,000 SO_2 allowances annually between 2010 and 2015, and more than 70,000 allowances per year after 2015. For NOx, PEF would have purchase more than 13,000 annual and 6,000 ozone season allowances per year starting in 2009. For mercury, PEF's emissions would be less than the number of allowances through 2017. Under this plan, PEF's bank of allowances would be sufficient to cover PEF's mercury emissions through 2025.

Q. How did the Company evaluate the potential economic impacts of the five alternative plans?

A. Once the alternative plans were developed, the plans were analyzed using PEF's detailed production costing model, PROSYM, through the year 2025. The PROSYM model simulates the operation of each generating resource on the PEF system, both existing and future, and how it is used to serve the forecasted peak demand and energy requirements of PEF's customers. The emission reduction characteristics of each control (scrubbers, etc.) were applied to the selected units in the alternative plans, and the resultant operation was simulated. PROSYM projects how much the units will be dispatched given their new characteristics, constraints, limitations, and fuel prices, and how they will interact with the other units in the PEF generating system. The results from PROSYM include projected generation and purchases, fuel usage, fuel and purchased power cost, reagent consumption, waste and by-product generation, and emissions of SO_2, NOx and mercury. The production costs (fuel, purchased power, reagent, and by-product) of each alternative plan were compared to the production costs of the baseline forecast (without emission controls) to determine the change in production costs for each alternative compliance plan.

The costs of compliance (other than the fuel and purchased power, reagent, and by-product costs that are determined by PROSYM) were developed by performing a detailed economic analysis of each control measure. These costs included the capital and O&M costs associated with the control measures used in the alternative plans. "Life-cycle" analyses were performed through the end of 2038, capturing the entire book life of the longest-lived measure (a scrubber or SCR installed on Crystal River Unit 4 or 5). The production costs were extrapolated from 2025 to 2038 assuming the PEF generating resources continue operating as they did in 2025. The prices of fuel, O&M, consumable, and by-products were escalated using standard corporate escalation rates (e.g., 2.5 percent for O&M) or the compound growth rates of the item over the last years of the respective price forecast.

The analyses calculated the revenue requirements associated with the controls selected for each alternative plan. These revenue requirements were then combined with the change in production costs to determine the total revenue requirements for each alternative plan. The cumulative present value of revenue requirements (CPVRR) was then used to compare the economic cost of the alternative plans.

Q. What were the results of the economic analysis of the alternative plans?

A. As described above, the economic impact of the alternative compliance plans were compared using the CPVRR. Figure 12-6 on Exhibit No. __ (DJR-3) shows the CPVRR of Plans A through E. Included in the CPVRR are the projected capital and O&M costs associated with controls, the projected cost of reagents (limestone and ammonia), credits for the sale of by-products (gypsum), the projected change in fuel and purchased power costs compared to the Baseline projection, and the projected cost of purchasing allowances. Figure 12-6 shows Plan A to be the most expensive plan. The high cost of Plan A is largely due to the capital costs associated with the emission controls installed, which are shown in Figure 12-7 on Exhibit No. __ (DJR-3). Plans B and C, which also would comply with CAIR without long-term purchases of allowances, are less costly than Plan A. This result is expected because only three of the Crystal River units have emission controls installed, and the projection of emissions more closely matches the number of allowances. Plan D is the plan with the lowest CPVRR. Plan E is more costly than Plan D, even though the capital requirements are considerably less than any other plan. This is caused by the significant amount of allowance purchases that would be required.

Figure 12-6 on Exhibit No. __ (DJR-3) includes the cost of allowances purchased for compliance with CAIR, but it does not include the value of allowances left in the bank. To place the plans on an economical level playing field, the value of the bank needs to be captured. Figure 12-8 on Exhibit No. __ (DJR-3) incorporates this economic value by assuming allowances are either sold or purchased each year. In this manner, the cost of installing extra controls, such as in Plan A, can be offset by selling any allowances available at the end of each year.

By selling allowances rather than banking them, the cost of Plans A through D are reduced; the cost of Plan E does not change since allowances are always purchased and never sold. The cost of Plans A and B are considerably closer and are virtually the same. The cost of Plan D also dropped slightly, reflecting the sale of allowances in the early years. After factoring in the value of the allowance bank, Plan D is still the plan with the lowest cost.

Q. What sensitivity analyses were conducted as part of the quantitative evaluation?

A. Perhaps the two greatest sources of uncertainty are the future prices of allowances (as discussed in Chapter 9 of the Clean Air Report) and the capital cost of emission control equipment (discussed in Chapters 4, 5 and 6 of the Clean Air Report). Therefore, we conducted sensitivity analyses to assess the impacts of variable allowance prices and capital costs. For the allowance sensitivity analyses, we determined the CPVRR of the alternative plans assuming low and high allowance prices, in addition to the results assuming median prices. For the capital cost sensitivity analyses, we examined the impact on the CPVRR of capital costs being 25 percent higher than expected. We only examined *higher* capital costs because increases in the costs of labor and materials make higher capital costs more probable than lower capital costs.

Q. What were the results of the sensitivity analysis of allowance costs?

A. Figure 12-9 on Exhibit No. __ (DJR-4) presents the CPVRR of the alternative plans assuming low and high allowance prices. The figure shows that over the wide range of allowance prices, Plan D is always the lowest cost plan. When allowance sales are included, the cost of Plans A, B, and C decrease under high allowance prices (compared to median prices) and increase if allowance prices are low. Because Plan E relies on significant allowance purchases, the costs associated with Plan E are highly variable when exposed to low and high allowance prices. By contrast, Plan D is impacted to only a small degree by allowance prices.

Q. What were the results of the sensitivity analysis of high capital costs?

A. Figure 12-10 on Exhibit No. __ (DJR-4) shows the CPVRR of the plans if capital costs are 25 percent higher than expected, as compared to the CPVRR of the plans under the base assumptions. As seen in the figure, Plan D remains the lowest cost plan among the alternatives. As would be expected, all the plans increase in cost. Plan A increases the most compared to the base assumption, simply because controls are installed on all of the Crystal River units in that plan. On the other hand, Plan E, which relies on significant allowance purchases for compliance and has the lowest amount of capital expenditures of the plans, has the smallest increase in costs.

Q. Please explain the Company's qualitative analysis of the alternative compliance plans.

A. Based on the planning objectives I previously described, the Company had to balance costs and risks to select an "optimal" strategy. The qualitative evaluation addressed factors that cannot easily be quantified. In particular, we evaluated the extent to which the plans allowed the Company to respond to unexpected changes in allowance prices and other market factors, as well as unanticipated regulatory developments.

Q. What were the results of the qualitative evaluation?

A. As discussed previously, Plan A is the only plan that complies with CAIR, CAMR, and the BART requirements of CAVR without purchasing allowances and without assuming BART controls will not be required for PEF units. Plan A does not provide much flexibility because emission controls are added to all four units at Crystal River as soon as possible, making it difficult to change direction based on new information. For example, if allowance prices turn out to be low, the Company will not be able to take advantage of the lower cost compliance method. Likewise, the overall cost reductions that might be anticipated by selling the allowances created by installing more controls than necessary will not be realized if allowance prices are low.

Both Plans B and C comply with CAIR without the need for buying allowances (except for NOx in the first couple of years) and they comply with CAMR. In addition to being the lower cost of the two plans, Plan C is preferable to Plan B because it calls for adding controls to Crystal River Unit 1, which allows PEF to install controls on Unit 2 in later years, if necessary. However, the addition of controls on Unit 1 also presents a disadvantage because Unit 1 is the smallest and oldest coal unit on PEF's system. Thus, Plans B and C are more flexible than Plan A in that they do not install controls on all Crystal River units right away. The FGD systems installed on Crystal River Units 1 and 2 are delayed until 2014 or 2015, which would give the Company time to observe allowance markets and for the possibility of new technologies, especially mercury controls, to be further developed.

Plan D achieves compliance by installing emission controls on PEF's two largest coal units (as well as NOx controls on the Anclote units). Because Crystal River Units 4 and 5 are also the newest coal units on the system, there should be less uncertainty in the cost to install the equipment on the units. It also will be easier to install controls on Units 4 and 5 because there are fewer physical obstacles around which to design and construct the control equipment. Plan D also provides flexibility. Because SO_2 and NOx emissions are below or near the amount of allowances PEF is to receive through 2014 (or beyond in the case of SO_2), this provides time for resolution of allowance market uncertainties. If allowance prices and the projection of future allowance prices increase, PEF has the ability to add controls to Crystal River Units 1 and 2 at a later date. Plan D also allows time for mercury control technologies to develop.

Plan E ensures compliance with CAVR because it calls for emission reduction measures on all three of PEF's units subject to BART. Because those units are the smallest steam units on the system, however, the emission reductions are not enough to reduce PEF's emissions below the number of allowances held. As a result, Plan E requires significant allowance purchases to comply with CAIR. Plan E's reliance on allowance purchases provides flexibility to adapt to possible future changes. However, the additional flexibility comes with significantly increased risk due to uncertainty in allowance prices. In PEF's judgment, the additional risk exposure is not worth the potential benefits.

Q. Which of the alternative plans has the Company selected for implementation?

A. PEF has selected Plan D for its Integrated Clean Air Compliance Plan.

Q. Why did the Company select Plan D?

A. Based on the results of the quantitative and qualitative evaluations, the Company concluded that Plan D is the least cost plan and it best meets all of PEF's planning objectives.

Q. How does the chosen Plan meet PEF's planning objectives?

A. First, the Plan meets the requirements of CAIR, CAMR and CAVR, as well as other state and federal environmental requirements.

Second, the plan manages risks and provides flexibility by striking a good balance between reducing emissions and making limited use of allowance markets. By calling for installation of controls on Crystal River Units 4 and 5 (PEF's largest and newest coal units) in the early years, the plan relies on minimal allowance purchases through 2014. This should provide time for the allowance markets to stabilize or for at least some of the uncertainties to be resolved. Should it appear that allowance prices are going to be high after

2014, the Plan provides PEF with the ability to install additional controls on the Crystal River units at a future date, potentially taking advantage of any technology improvements that develop in the interim. The Plan also allows time for finalization of State Implementation Plan revisions, at which time PEF can fine-tune the Plan, if necessary. Additionally, should PEF experience higher load growth than expected, or if plans for future baseload units change, PEF could then add controls on Crystal River Units 1 and 2, if necessary.

Finally, Plan D controls costs. As shown in Exhibit No. __ (DJR-3), the CPVRR for Plan D are projected to be approximately $100 million less that the next lowest cost plan under the base assumptions. As discussed above, Plan D is also the lowest cost plan when allowance price and capital cost uncertainties are factored into the analysis. Thus, the Plan is the most cost-effective means of achieving compliance at the lowest reasonable cost to PEF's customers.

Q. Does this conclude your testimony?

A. Yes, it does.

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

Environmental Cost Recovery Clause

DIRECT TESTIMONY OF
JOHN HOLLER

March 31, 2006

Q. Please state your name and business address.

A. My name is John Holler. My business address is 15760 West Power Line Street, Crystal River, Florida 34428.

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

A. I am employed by Progress Energy Florida, Inc. (PEF) as a Principal Engineer in the Plant Construction Department.

Q. What are your responsibilities in that position?

A. I am responsible for the engineering, budget development, and completion of major environmental control projects at PEF's four-unit coal-fired Crystal River plant, and PEF's five oil-fired units at the Anclote and Bartow Plants. Among other things, our department helps develop and initiate air compliance strategies for PEF's fleet of fossil units in response to regulatory and company initiatives.

Q. Please describe your educational background and professional experience.

A. I received a Bachelors of Science Degree in Mechanical Engineering from Cornell University. I have thirty years of experience in all phases of the power generation business including operations, maintenance, fuels, environmental compliance, capital additions, new plant development and acquisitions. I have been involved in financial and technical aspects of managing, evaluating and developing power generation assets, including air pollution control projects. During my thirty year career in the power industry, I have been involved in the assessment, design, and installation of numerous air emission control projects, including controls on nitrogen oxide (NOx) emissions, such as Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) systems, Low NOx burners (LNB) and over-fire air (OFA) systems, as well as Flue Gas Desulphurization systems (FGD or "scrubbers") for control of sulfur dioxide (SO_2) emissions.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring Exhibit No. __ (JH-1) which provides a conceptual level schematic of the primary emission control technologies for utility boilers, such as those operated by PEF.

Q. What is the purpose of your testimony?

A. In Order No. PSC-05-0998-PAA-EI, the Commission found that costs for complying with the new Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) are eligible for recovery through the ECRC subject to PEF's demonstration that costs for specific projects are reasonable and prudent as they are submitted for recovery in the annual ECRC proceedings. Since that time, PEF has conducted extensive analysis to develop an Integrated Clean Air Compliance Plan, which is presented in a report provided as Exhibit No. __ (DJR-1) to Mr. Roeder's pre-filed direct testimony. The primary purpose of my testimony is to explain how PEF's Integrated Clean Air Compliance Plan will meet the requirements of the CAIR, CAMR, and the new Clean Air Visibility Rule (CAVR). Among other things, I will provide an overview of the new regulations, describe various emission control technologies that PEF has analyzed, and discuss uncertainties associated with implementation of PEF's compliance plan.

Q. Please describe your role in the development of PEF's Integrated Clean Air Compliance Plan.

A. Initially, I worked with the Company's environmental professionals in evaluating the requirements of CAIR, CAMR, and CAVR to estimate the amount of emission reductions that PEF would need to achieve in order to comply with the new regulations. I analyzed the technical feasibility of various emission reduction measures for those units. I also developed emission reduction and cost estimates for various control technologies that were used in developing and analyzing alternative compliance plans. The primary emission controls for utility boilers are discussed below and shown at a conceptual level in the schematic attached as Exhibit No. __ (JH-1) to my testimony.

Q. You mentioned that you reviewed and evaluated the requirements of the new regulations. Please briefly describe the Clean Air Interstate Rule (CAIR).

A. CAIR was signed by the Acting Administrator of the U.S. Environmental Protection Agency (EPA) on March 10, 2005. CAIR requires significant reductions of SO_2 and NOx emissions from power plants in 28 eastern states and the District of Columbia through an emissions cap-and-trade program or other means. When fully implemented, CAIR is expected to reduce SO_2 emissions in these states by over 70 percent and NOx emissions by approximately 65 percent as compared to current levels. CAIR will be implemented by the affected states through revised State Implementation Plans (SIPs) designed to ensure that state-specific emission budgets are achieved by the required deadlines. Affected states are required to submit their SIP revisions to EPA for approval no later than September, 2006.

Q. What are the sulfur dioxide (SO_2) requirements of CAIR?

A. CAIR requires significant reductions in SO_2 emissions in the affected 28-state region. The reductions will be implemented in two phases – the first phase beginning in 2010 and the second phase beginning in 2015. CAIR encourages states to use the cap-and-trade approach that was established in Title IV of the 1990 Clean Air Act Amendments, which is also known as the acid rain program. Under Title IV, SO_2 emissions allowances were allocated to all affected units. CAIR implements the additional reductions by increasing the number of allowances required to offset SO_2 emissions. Beginning in 2010, CAIR requires two allowances for each ton of SO_2 emitted, as compared to the one allowance per ton requirement under the existing Title IV program. Beginning in 2015, each ton of emissions will require 2.86 allowances. Based on these changes, PEF estimates that the Company would need to reduce its SO_2 emissions between 66,000 and 84,000 tons per year, but generally around 72,000 tons per year, in order to comply with CAIR without purchasing SO_2 allowances.

Q. What are the nitrogen oxides (NOx) requirements under CAIR?

A. CAIR also requires significant reductions in NOx emissions in the affected 28-state region. As with SO_2, the NOx emission reductions also will be implemented in two phases – the first phase beginning in 2009 and the second in 2015. CAIR encourages use of a cap-and-trade approach to achieve the required emissions reductions. Under EPA's model cap-and-trade program, EPA will allocate emission allowances to each participating state. For instance, Florida would be allocated 99,445 allowances from 2009-2014 and 82,871 allowances in 2015 and thereafter. Participating states will then allocate their budgeted allowances to individual emitting units. Allocations will be made separately for both the annual and "ozone season" (May through September) periods. Assuming Florida implements a NOx cap-and-trade program, PEF estimates that its NOx emissions would have to be reduced by approximately 21,000 to 28,000 tons per year and by approximately 11,000 to 14,000 tons during the ozone season (May-September) to comply with CAIR without purchasing NOx allowances.

Q. Please briefly describe the Clean Air Mercury Rule or "CAMR."

A. The final CAMR was signed by the Acting EPA administrator on March 15, 2005. CAMR will be implemented in two phases: the first phase beginning in 2010 and the second in 2018. When fully implemented in 2018, CAMR will result in a 70 percent reduction in mercury emissions from coal-fired power plants nationwide. Like CAIR, CAMR encourages states to implement a cap-and-trade program to achieve the required emissions reductions. Under the CAMR cap-and-trade program, EPA will allocate mercury emissions allowances to each state, which will then allocate them to individual coal-fired units. In its initial plan for CAMR adoption, the Florida Department of Environmental Protection (DEP) proposed to implement unit-specific emission limits and compliance schedules rather than the federal cap-and-trade approach. If the final DEP rule imposes unit-specific emission limits rather than a cap-and-trade approach, PEF would not have the flexibility to meet its emission allocations by controlling some units but not others or by purchasing allowances. CAMR also requires that Continuous Mercury Monitoring Systems be installed on all coal-fired units by January 1, 2009, one year prior to implementation of the Phase I emission caps.

Q. Please briefly describe the Clean Air Visibility Rule or "CAVR."

A. On June 15, 2005, EPA finalized amendments to the 1999 regional haze rule now known as the Clean Air Visibility Rule (CAVR). Among other things, the final version of CAVR requires best available retrofit technology (BART) controls for certain industrial facilities emitting air pollutants that reduce visibility in certain "Class I" areas, including national parks and wilderness areas. There are four such areas in Florida, including Everglades National Park, Chassahowitzka National Wildlife Refuge and the St. Marks and Bradwell Bay Wilderness Areas.

BART requirements apply to facilities that began operation between August 1962 and August 1977. These include four PEF units: Anclote Unit 1, Bartow Unit 3, and Crystal River Units 1 and 2. However, the final CAVR provides that participation in the CAIR cap-and-trade program may substitute for BART requirements. Thus, if DEP adopts the CAIR cap-and-trade programs, PEF may not be required to install BART on the units subject to CAVR. Even in states adopting CAIR, however, controls may be required for individual units that are shown through modeling to contribute significantly to visibility impairment in a Class I area.

Q. What is the current status of DEP's implementation of the new federal rules in Florida?

A. As noted above, CAIR requires affected states to submit SIP revisions to EPA for approval by September 2006. DEP has begun the SIP revision process and intends to meet the September 2006 deadline. In initial rule development workshops, DEP indicated that it intends to adopt SO_2 and NOx cap-and-trade programs to implement CAIR requirements. However, the details will not be known until DEP finalizes its SIP revision. If DEP does not meet the September 2006 SIP deadline, the federal SO_2 and NOx cap-and-trade programs would automatically take effect under a Federal Implementation Plan (FIP) promulgated by EPA on March 15, 2006.

Much like CAIR, CAMR and CAVR requires states to submit SIP revisions to EPA for approval by November 17, 2006 and December 17, 2007, respectively. DEP has begun the SIP revision process for both rules and plans to comply with the applicable deadlines.

Q. Can the company wait until DEP's SIP revisions are finalized before it begins to implement its compliance plan?

A. No. As discussed below and detailed in the report provided as Exhibit No. __ (DJR-1) to Mr. Roeder's testimony ("Clean Air Report'), PEF's compliance plan includes the installation of emission controls, such as SCR and LNB/OFA systems for NOx and FGD systems for SO_2. Based on the Company's experience, SCR projects generally require approximately 30-36 months to complete, while FGD projects generally require approximately 42-48 months and LNB/OFA projects generally require 18-24 months. Although some uncertainty remains as to how the federal rules will be implemented in Florida, given the long lead times for installing these pollution control systems, PEF must begin implementing its compliance plan if the Company is to meet the CAIR compliance deadlines (i.e., 2009 for NOx and 2010 for SO_2). Moreover, there is little, if any, reason to believe that PEF will be allocated more emission allowances under the final DEP SIP revisions than under the EPA cap-and-trade programs.

Q. You previously mentioned that you reviewed emissions information for PEF's generating units to identify which units could be controlled to achieve the likely amount of required emission reductions. Which units did you identify?

A. As discussed in more detail in Chapter 2 of the Clean Air Report, with the repowering of PEF's Bartow Units, the Crystal River and Anclote units will contribute over 80 percent of PEF's projected SO_2 and NOx emissions total, and the Crystal River units contribute all of PEF's projected mercury emissions under CAMR. For these reasons, our analyses focused primarily on the technologies available for the Crystal River and Anclote units.

Q. Please describe the Crystal River and Anclote Units.

A. Crystal River Units 1 and 2 are similar coal-fired units, with Unit 1 nominally rated at 400 MW and Unit 2 nominally rated at 500 MW. These units currently burn coal with approximately 1.8 lbs/mmBtu of sulfur content to meet at permitted SO_2 emissions limit of 2.1 lbs/mmBtu. Both units have had Low-NOx Burners (LNBs) and Overfire Air (OFA) systems installed to meet annual permitted NOx emissions limits of 0.4 lbs/mmBtu.

Crystal River Units 4 and 5 are virtually identical coal-fired units that are nominally rated at 740 MW each. These units currently burn "compliance" coal with a sulfur content of 1.2 lbs/mmBtu to meet permitted SO_2 emissions limits of 1.2 lbs/mmBtu. Both units have the original coal burners that were guaranteed for a maximum NOx emissions level of 0.7 lbs/mmBtu. Tuning of the coal and air flows through the burners has allowed the units to comply with their current annual permitted NOx limit of 0.5 lbs/mmBtu.

Anclote Units 1 and 2 are nearly identical units that are nominally rated at 500 MW each. The units are permitted to burn residual fuel oil with an annual average SO_2 content of 1.5 lbs/mmBtu. The units also have the capability of burning natural gas (when available) up to 40 percent of the total heat input to the boilers. No NOx controls have been retrofitted to these boilers and the units are currently not subject to permit limits for NOx emissions. The units currently operate with NOx emissions averaging approximately 0.34 lbs/mmBtu.

Q. You previously mentioned that you analyzed and developed cost estimates for various emission controls. What SO_2 emission controls did you evaluate?

A. As detailed in Chapter 4 of the Clean Air Report, for SO_2, we evaluated the use of wet and dry FGD or "scrubber" systems. In addition to these emission control systems, as discussed in Mr. Roeder's testimony and Chapters 10 and 11 of the Clean Air Report, the Company also analyzed fuel switches as a potential means of reducing SO_2 emissions.

Q. Please explain the difference between "wet" and "dry" FGD systems.

A. Both types of FGD systems are also known as "scrubbers", as they "scrub" SO_2 from the flue gas of the boiler. In a dry FGD system, flue gas from the boiler is ducted into a large "Spray Dry Absorber Vessel" that is normally installed at the outlet of the boiler, prior to the boiler's particulate control equipment. As the boiler flue gas passes through this vessel, a slurry of lime and water is sprayed into the gas, causing a chemical reaction between the SO_2 in the gas and the lime and the alkali in the fly ash to form calcium sulfite and calcium sulfate. The flue gas containing the fly ash and the calcium sulfite/sulfate then exits the absorber vessel and enters the particulate collection equipment where the majority of the ash and calcium sulfite/sulfate are collected. The "scrubbed" flue gas is then directed to the chimney for release into the atmosphere.

A wet FGD system also utilizes an absorber vessel into which the boiler's flue gas is ducted. However, with the wet FGD system, the absorber vessel is located after the particulate control equipment, such that the fly ash collected prior to the wet FGD system does not become part of the wet FGD's solid waste stream. The wet FGD system utilizes limestone, which must be pulverized and mixed with water to form a slurry that is sprayed into the absorber vessel. As the boiler flue gas passes through the limestone slurry spray, a chemical reaction occurs between the SO_2 in the flue gas and the calcium carbonate in the limestone to form calcium sulfite. If oxygen is introduced into the reaction inside the absorber vessel, the calcium sulfite is converted into calcium sulfate, also known as synthetic gypsum. When limestone with a high calcium carbonate purity is used, the resulting synthetic gypsum can be used to manufacture wallboard.

Q. What are the relative advantages and disadvantages of "dry" versus "wet" FGD systems?

A. Dry FGD systems generally have lower initial capital costs and lower O&M costs because they are somewhat simpler in design and require less equipment. However, there are a number of advantages to wet FGD systems. Wet FGDs are generally designed with SO_2 removal efficiencies of 97 percent, while dry FGD SO_2 removal efficiency is generally in the range of 90-95 percent. Wet FGD allows for a much wider range of coals, which allows more flexibility to purchase lower cost, higher sulfur coals than would be possible with a dry FGD system. Limestone reagent costs are less with wet FGD systems. And, as noted above, unlike dry FGDs which produce byproducts that have no commercial use and generally must be landfilled, wet FGDs produce synthetic gypsum that can be sold and they allow for the continued sale of fly ash. Considering all these factors together, particularly the fuel flexibility associated with wet FGD systems, the total cost of a dry FGD system is greater than the total cost of a wet FGD system.

Q. What NOx emission controls did you evaluate?

A. While NOx emissions can be reduced by burning different fuels, such as natural gas, significant emission reductions can only be made through changes in the combustion process or the addition of post-combustion controls. For this reason, as detailed in Chapter 5 of the Clean Air Report, our analysis of NOx reduction measures focused on combustion modifications and post-combustion controls.

Q. Please explain the difference between combustion and post-combustion NOx controls.

A. Combustion staging is commonly used to control NOx emissions by reducing the amount of nitrogen in the combustion air that is oxidized during combustion, known as "thermal NOx". LNBs and OFA are the commonly used methods to stage combustion. LNBs typically create "zones" of combustion with varying ratios of fuel and combustion air. LNBs are a proven technology for reducing NOx, and are often the initial NOx reduction step taken due to their "low" initial cost, NOx removal effectiveness (approximately 20 to 30 percent), and ease of installation. OFA systems take some of the combustion air that would normally be available to the burners and redirect it so as to enter the combustion process after the initial combustion has occurred at the burners. There are several variations of OFA systems, but their feasibility and NOx reduction efficiency depend upon the specific type of boiler in question.

Post-combustion systems include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) systems, both of which utilize ammonia-based reagents to promote the conversion of the NOx created during combustion to nitrogen, carbon dioxide and water before it is emitted to the atmosphere. While these technologies generally have higher capital and operating costs, they are also more effective at reducing NOx emissions than LNBs and OFA.

Combinations of combustion modifications and post-combustion technologies are often used for NOx emission control. For instance, installing a relatively low-cost combustion modification, such as LNBs, can reduce the overall capital and operating costs of a post-combustion system such as an SCR. By using LNBs to reduce the NOx levels produced in combustion, the SCR will use less reagent (thus, reducing operating cost) and can be made "smaller" (thus, reducing capital cost), or the SCR can be made the same size and remove more tons of NOx, thus reducing the number of NOx allowances needed.

Q. What mercury emission reduction measures did the Company evaluate?

A. As detailed in Chapter 6 of the Clean Air Report, we evaluated the synergistic mercury reduction effects of NOx, SO_2 and particulate controls, as well as mercury-specific controls such as powdered activated carbon injection technology.

Q. How did you analyze the feasibility and costs of the various control options?

A. We used a number of sources, including studies performed by engineering consultants, internal studies, equipment vendors, and the experience gained from Progress Energy projects which have already been installed or are in progress to assess the cost and feasibility of various compliance options.

Q. What SO_2 emission reduction measures has PEF chosen to pursue in its Integrated Clean Air Compliance Plan?

A. As discussed more fully in Chapter 3 of the Clean Air Report, the SO_2 component of PEF's compliance plan includes installation of wet scrubbers on Crystal River Units 4 and 5, switching Crystal River Units 1 and 2 to burn low-sulfur (1.2 lbs SO_2 per mmBtu) "compliance" coal beginning in 2010, and burning low sulfur oil and natural gas at Anclote Units 1 and 2 starting in 2010. These control options are the lowest incremental cost options available to PEF and provide most, but not all, of the SO_2 emission reductions required. As discussed more fully in Mr. Roeder's testimony and accompanying Clean Air Report, PEF also plans to utilize the SO_2 allowance market as part of the Integrated Clean Air Compliance Plan.

Q. What NOx emission reduction measures has PEF chosen to pursue in its integrated compliance plan?

A. The NOx component of the plan includes the installation of LNBs and SCRs on Crystal River Units 4 and 5, and the installation of LNBs with separated OFA controls on Anclote Units 1 and 2. These control options are among the lowest incremental cost options available to PEF and they provide most, but not all, of the reductions required by CAIR. As discussed more fully in Mr. Roeder's testimony and the Clean Air Report, PEF also plans to utilize the NOx allowance market as part of its Integrated Clean Air Compliance Plan.

Q. How will PEF's compliance plan comply with CAMR?

A. The combination of wet scrubbers and SCRs on Crystal River Units 4 and 5 work together to provide a co-benefit of reducing emissions of mercury. PEF expects mercury emissions to be reduced below the required number of allowances between 2010 and 2017. As discussed more fully in Mr. Roeder's testimony and the Clean Air Report, the Plan also includes installing powdered activated carbon injection systems on Crystal River Unit 2 in 2017 to further reduce mercury emissions in order to achieve CAMR's second phase requirements.

Q. How will PEF's plan comply with CAVR?

A. As discussed above, the final CAVR provides that participation in the CAIR cap-and-trade program may substitute for BART requirements. While additional controls may be required by states for individual units that are shown through modeling to contribute significantly to visibility impairment in a Class I area, PEF expects that installing controls on the larger Crystal River Units 4 and 5 will significantly improve the visibility in Class I areas, more so than installing controls on Crystal River Units 1 and 2, which are the only Crystal River units potentially subject to BART.

Q. What near term investments must the Company make in order to meet the applicable regulatory deadlines?

A. In order to complete the projects included in PEF's Integrated Clean Air Compliance Plan within the planned installation times, the study and design work started in 2005 must be continued, and significant additional engineering and design work must be completed. In addition, construction, water supply and environmental permit applications must be prepared and submitted. PEF also must staff Project and Plant Integration Teams to direct the project work and prepare the plant for operation of the new equipment as it is commissioned.

The primary focus in 2006 will be on the design, engineering, permitting and initial procurement commitments for the Crystal River Unit 4 SCR to achieve a startup date of Spring 2008 and for the Crystal River Unit 5 FGD to achieve a startup date of Spring 2009. Since Units 4 and 5 are virtually identical, the majority of the design and engineering being completed for one unit's FGD or SCR will be applicable to the other unit. Thus, while the focus will be on the FGD and SCR for the unit scheduled for completion first, there will be design and engineering work performed to support the subsequent installations and thereby facilitate the most efficient procurement of equipment and sequencing of construction.

Many of the studies and design work that began in 2005 are continuing into 2006. These studies and other activities are detailed in Chapter 3 of the Clean Air Report. In addition to this study, design and engineering work, procurement commitments will need to be made beginning in mid-summer of 2006 for long lead time equipment, such as induced draft fans, grinding mills, absorber materials, SCR catalyst, gypsum dewatering equipment, controls systems, and others. In addition, PEF will need to contract with various specialty sub-contractors (such as chimney constructors and absorber vessel constructors) in 2006 to ensure their availability to support the construction schedule. Indications are that with the recent amount of activity in these fields as a result of CAIR and CAMR, many of these specialty contractors are already committed to other work and not in a position to accept new contracts.

Q. Are there any uncertainties that may lead to adjustments of the compliance plan in the future?

A. While a significant amount of study, engineering, and analysis has already been completed, there are still outstanding issues that require further investigation. One of the primary issues relates to PEF's Anclote units. During initial development of the compliance plan, PEF assumed that pollution control projects, such as the Anclote LNB/SOFA projects, were exempt from New Source Review (NSR) permitting requirements. As discussed in Chapters 2 and 3 of the Clean AIR Report, however, in 2005 a federal court vacated the NSR exemption for pollution control projects and, effective February 2006, the exemption has been removed from Florida's SIP. As a result, the Anclote LNB/SOFA projects, as well as the Crystal River projects, may now be subject to NSR. Because significant controls will be installed at Crystal River under the current plan, NSR would not be expected to have a major impact for Crystal River. At Anclote, however, the LNB/SOFA projects contemplated for NOx control could potentially increase particulate emissions and thereby trigger NSR. Additional study is needed to determine the magnitude of potential increases, whether additional particulate controls would be needed to meet NSR requirements, and whether the cost of such controls, when combined with the expected costs of the LNB/SOFA systems, would increase the cost per ton of NOx removed above the expected cost of NOx allowances. While CAIR compliance can be achieved by purchasing additional NOx allowances if LNB/SOFA projects are not completed at Anclote, CAVR could require the installation of controls for the reasons discussed in Chapter 2 of the Clean Air Report.

For the Crystal River projects, there are a number of outstanding issues for which studies remain to be completed. Perhaps the most critical action item is completion of the test wells and hydrology studies needed for the consumptive water use permit. As part of the permitting process, PEF will need to determine the quality and sources of limestone and the quality of the FGD makeup water (i.e., freshwater vs. saltwater). These issues are critical factors in determining wastewater treatment and disposal options.

Also for Crystal River, there is uncertainty regarding compliance with CAMR. Although much research and testing is being conducted, including projects with which Progress Energy is involved, much more needs to be determined before compliance with CAMR can be assured. As discussed in Chapter 6 of the Clean Air Report, significant questions remain concerning the effectiveness of current mercury removal technologies, the ability of Continuous Mercury Monitoring Systems to accurately measure and report the mercury emissions from boilers on a long term basis, the levels of mercury in different coals and how the presence of other trace elements in the coal impacts the ability of the various technologies to reduce mercury emissions.

In addition to these specific project and technology uncertainties, there are uncertainties related to the regulations themselves and how DEP and EPA will implement them. While the EPA rules offer guidance, a number of issues remain unresolved, including whether or not cap-and-trade systems will be incorporated for all pollutants (including mercury), the number of NOx (both annual and ozone-season) and mercury allowances that PEF will be allocated initially and in the future, and whether PEF units will need to install additional controls as a result of visibility modeling for nearby Class I areas. As these issues are resolved, PEF will continue to review and, if necessary, adjust its compliance plan to assure timely and cost-effective compliance with all applicable regulations.

Q. In light of the uncertainties you have discussed, are the near term investments you described reasonable and prudent?

A. Absolutely. As discussed above, most of the near term investments relate to SCR and FGD projects at Crystal River Units 4 and 5. These projects provide the greatest amount of emission reductions at the lowest cost per ton removed. For that reason, they will be implemented regardless of the final outcome of DEP's SIP revision process. In addition, by calling for installation of controls on Units 4 and 5 early in the process, PEF's Integrated Clean Air Compliance Plan provides flexibility to install additional controls on other units if necessary to respond to unexpected regulatory developments resulting from DEP's SIP revision process or permitting review for the Anclote projects. All other near-term investments are necessary to ensure that PEF's compliance plan is implemented and, if necessary, adjusted to achieve compliance with the aggressive CAIR/CAMR/CAVR deadlines in a cost-effective manner.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

THOMAS LAWERY

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

SEPTEMBER 1, 2006

Q. Please state your name and business address.

A. My name is Thomas Lawery. My business address is 8202 West Venable Street, Crystal River, Florida 34429.

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

A. I am employed by Progress Energy Florida, Inc. (PEF) as Manager of Regional Engineering.

Q. What are your responsibilities in that position?

A. I provide engineering and technical support to the fossil power plants for PEF. This includes projects and troubleshooting for the Crystal River fossil plants, Anclote plant, Suwannee plant and Bartow plant.

Q. Please describe your educational background and professional experience.

A. I have a B.S. degree in Electrical Engineering from Florida State University and I am presently pursuing a MBA at the University of Tampa. I am a registered Professional Engineer in Florida with seventeen years experience in fossil power plant operation and design. I have been involved in financial and technical aspects of managing, evaluating and developing power generation assets.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the Company's request for recovery of costs for installation and operation of modular cooling towers at PEF's Crystal River plant (the Modular Cooling Tower Project).

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring Exhibit No. __ (TL-1), a chart that shows cooling water inlet temperatures and unit loads for the time period May 1, 2006 through July 31, 2006. It also includes the associated amount of de-rates that have been necessary to ensure compliance with the permit limit for the temperature of the cooling water discharged from PEF's Crystal River plant during the same time period. PEF will provide further information for the August 1, 2006 through mid-September 2006 time period to the Commission by September 30, 2006.

Q. Have you previously filed testimony before this Commission?

A. Yes. I provided testimony in Docket 060162 in support of PEF's request to allow recovery under the Environmental Cost Recovery Clause for the Modular Cooling Tower Project.

Q. Please describe the Modular Cooling Tower Program.

A. The purpose of the project is to enable PEF to comply with the Florida Department of Environmental Protection permit limit on the temperature of cooling water discharges from the Crystal River plant in a manner that minimizes "de-rates" of Crystal River Units 1 and 2 (CR-1 and CR-2). The Project involves installation and operation of modular cooling towers in the summer months (mid-May through mid-September) in order to reduce the discharge canal temperature. This will enable PEF to reduce the number and extent of de-rates and thereby reduce replacement fuel and purchase power costs.

Q. When were the Modular Cooling Towers placed in service?

A. The Modular Cooling Towers were placed in service in June 2006.

Q. Have the Modular Cooling Towers been effective at reducing the number of summer de-rates?

A. Yes. The Modular Cooling Towers have successfully reduced the number of required de-rates for Crystal River Units 1 and 2. As illustrated in Exhibit No. _ (TL-1), PEF has only had to de-rate once for thermal permit issues through the end of July 2006 since the modular cooling towers were placed into operation.

The modular cooling towers are estimated to have reduced necessary de-rates by 23,955 MWh's.

Q. Have the Modular Cooling Tower been able to achieve their design capacity?

A. The Modular Cooling Towers have been extremely effective at reducing the temperatures of the cooling water discharged. PEF is still working with the vendor, Aggreko, to fine tune the performance of the cooling towers and maximize their efficiency.

Q. What have been the actual inlet water temperatures for 2006?

A. As illustrated in Exhibit _ (TL-1), the inlet water temperatures during the potential derate period of May 1, 2006 to July 31, 2006 have ranged from 73.2 to 90.7 degrees Fahrenheit.

Q. What was the frequency and megawatt hour level of both actual and avoided summer de-rates for Crystal River Units 1 and 2 from mid-May 2006 through July 2006?

A. The frequency and MWh level of both actual and avoided summer de-rates are illustrated in Exhibit _ (TL-1).

Q. Are you using the model that was developed by the University of Florida to calculate the avoided summer de-rates that was described in Docket 060162? If not, please explain why.

A. No. We are not using the model that was developed by the University of Florida to perform our economic analysis on the avoided de-rates. The University of Florida model was primarily designed to assist the plant operators in anticipating POD temperatures 3 hours in advance to ensure compliance with environmental requirements. Initially, PEF planned to also use this model to calculate avoided derates. After further analysis, PEF has determined that the model is not well suited to calculate de-rates for long periods of time. As a result, PEF has developed another model internally that will do a better job of forecasting avoided de-rates.

Q. How are you calculating the avoided summer de-rates in 2006 since installation of the modular cooling towers?

A. We are using a model that looks at the actual measured hot water temperature in the canal and actual measured cool water temperature from the permanent helper cooling towers to predict what the POD temperature would have been without the modular cooling towers. This is hourly data from the Plant Information system for May 1, 2006 through July 31, 2006. For hours where a de-rate would have been required, the model calculates the amount of de-rate that would have been necessary in order to achieve the targeted POD temperature. The logic for the de-rate is to begin with Unit 1 and continue de-rates until the target POD temperature is achieved or the unit is de-rated to minimum load (120 MW). If more de-rates are required, the model then de-rates Unit 2 until either the target is achieved or the unit is de-rated to minimum load (120 MW).

Q. Can you quantify any fuel cost and net fuel cost savings attributable to this project?

A. The net fuel savings attributable to this project will be calculated by using an industry standard unit commitment dispatch model. For each event where derates were avoided, two separate cases will be modeled, one case with actual generation of CR-1 and CR-2, and another case with generation of CR-1 and/or CR-2 reduced to the extent of calculated avoided derates. The fuel cost differences between the cases will then be calculated to arrive at the gross benefit of reduced fuel costs associated with avoided derates as a result of the modular cooling towers.

Regarding fuel costs associated with auxiliary loads, a total of 1,969MWh were consumed to operate the modular cooling towers during the May 1, 2006 to July 31, 2006 period as reflected on Exhibit No.__ (TL-1). The fuel costs to supply auxiliary loads will be estimated by multiplying the aggregate auxiliary consumption by average replacement power costs.

The net of the two aggregated numbers will yield the Net Fuel Cost Savings. Unfortunately, the required analyses are time consuming and results of the May

1, 2006 through July 31, 2006 period could not be completed in time to support this filing. PEF will provide this information to the Commission by September 30, 2006.

Q. **Can you provide any third party projections of future Gulf Water temperatures?**

A. No. We do not have in our possession any third party projections of future Gulf Water temperatures. However, even if those projections were available, temperature alone may not be a good indicator of water temperatures in the intake canals, as there are multiple other factors that can impact the temperature such as: varying water temperatures near the plant from day to day due to cloud cover, rainfall, tides, and the depth of water near the plant (relatively shallow).

Q. **What costs do you expect to incur in 2007 in connection with the Modular Cooling Tower Program (Project 11)?**

A. PEF is projecting to spend approximately $3.4 million in O&M for rental fees.

Q. **Does this conclude your testimony?**

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL DIRECT TESTIMONY OF

THOMAS LAWERY

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 060007-EI

OCTOBER 13, 2006

Q. Please state your name and business address.

A. My name is Thomas Lawery. My business address is 8202 West Venable Street, Crystal River, Florida 34429.

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

A. I am employed by Progress Energy Florida, Inc. (PEF) as Manager of Regional Engineering.

Q. Have you previously submitted direct testimony in this docket?

A. Yes. On September 1, 2006, I submitted direct testimony in support of PEF's request to recover costs of the installation and operation of the modular cooling towers (MCTs) at PEF's Crystal River Plant. Such costs have been included in PEF's proposed ECRC factors subject to refund depending upon the Commission's final action on PEF's petition to recover the costs of the MCT Project in Docket No. 060162-EI.

Q. What is the purpose of your supplemental testimony?

A. In accordance with Staff's recommendation in Docket No. 060162-EI, the purpose of my testimony is to provide analysis of the cost savings resulting from the MCT Project in 2006. Such analysis was not available when I filed my direct testimony on September 1, 2006.

Q. Are you sponsoring an exhibit to your revised supplemental testimony?

A. Yes. I am sponsoring Exhibit No.__ (TL-2), which provides a comparison of the Crystal River inlet water temperatures for the summers of 2005 and 2006.

Q. Can you quantify the fuel costs and net fuel cost savings attributable to the MCT Project?

A. Yes. Using the methodology explained in my direct testimony, the calculation of gross benefits from avoided derates yields a total of $4,033,020. The value of additional auxiliary loads to power the modular cooling towers is $289,057. The net of the two numbers yields net savings of $3,743,963.

Q. Has PEF conducted any analyses of the factors affecting cost savings attributable to the MCT Project?

A. Because the calculated actual fuel savings for 2006 were below forecasts performed prior to installation of the modular towers, PEF conducted additional analyses to identify the key factors that influenced the variation between forecast and actual results. These factors are discussed below.

- **Economy Purchases**: Variances associated with actual economic purchase performance relative to the forecast significantly affected benefits attributable to the MCT Project in 2006. Notably, economic purchases were particularly significant for the month of August, when the bulk of the avoided derate benefits also occurred. PEF purchased 86 GWh more than was predicted in the forecast model. Multiplying the increase in economy purchases by the average $/MWh savings, PEF estimates that the increase in actual economy purchases reduced costs by $4.4 million relative to the predicted cost basis that the avoided derates were forecasted against. While not every hour of economy purchases coincided with a derate, and because derates were most prominent in the highest cost generation hours, it is reasonable to conclude that a large portion of the economy purchases had a direct reduction impact on the calculated actual benefit of the MCTs. Such purchase savings are opportunistic events which cannot reasonably be predicted and, while decreasing the perceived benefit of MCTs, they do represent a significant benefit to PEF's customers. It is not practical to assess the economy purchases' exact impact on the MCTs' avoided derate benefit, but it is reasonable to project a variance of at least $2 million.

- **Fuel Prices**: The very mild winter of 2005/2006 led to a significant decline in the price of natural gas between the time that the forecast was performed and the summer months of 2006. Daily (actual) spot prices for natural gas ranged between $2/mmbtu and $5/mmbtu lower than the forecast. Actual daily dispatch prices for No. 2 oil on the other hand were slightly higher than the forecast. Taking these two factors and applying a reasonable assumption of contribution from each (based on the calculated average daily replacement power costs), it appears that the decrease in natural gas prices reduced the calculated actual benefit of MCTs by approximately $2.1 million.

- **CR3 Unplanned Outage**: Actual CR3 generation for the month of August was 77GWh below that predicted in the forecast due to several atypical events. The most significant event was a forced outage due to a feedwater piping leak inside the reactor building. Absent this forced outage, avoided derates would have been approximately 16 GWh higher, which would have increased the calculated actual benefit of MCTs by an additional $1.4 million.

- **Summary**:

Millions	Savings Difference
$3.7	Estimated Avoided Derates
$2.0	Economy Purchases
$2.1	Fuel Cost
$1.4	CR-3 Unplanned Outage
$9.2	Total

As shown in the table above, the cumulative effect of these factors would bring the avoided derate benefit into the $9.2 million range. While it is probable that cooler intake canal temperatures also played a role in the lower than projected savings, it is not possible to directly quantify such impact since there are other factors that affect the magnitude of thermal discharge-related derates. The comparison of historical data from 2005 to that of 2006 in Exhibit No.__ (TL-2) shows that the 2006 inlet canal water temperatures were lower than observed in 2005, but not dramatically so.

Irrespective of whether the 2006 results came in high or low, judging the MCT project on a single year would be premature and inappropriate. The variability of results indicated by this review supports PEF's decision to pursue this as a temporary project while additional data is gathered. PEF continues to believe that over the planned five year span of operation, the MCTs will provide significant benefits to ratepayers.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 060007-EI

APRIL 3, 2006

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as the Manager of Regulatory Issues in the Regulatory Affairs Department.

Q. Have you previously testified in the predecessors to this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the Environmental Cost Recovery (ECR) Clause true-up costs associated with FPL Environmental Compliance activities for the period January through December 2005.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes, I have. It consists of eight forms.

- Form 42-1A reflects the final true-up for the period January through December 2005.
- Form 42-2A consists of the final true-up calculation for the period.
- Form 42-3A consists of the calculation of the interest provision for the period.
- Form 42-4A reflects the calculation of variances between actual and estimated/actual costs for O&M Activities.
- Form 42-5A presents a summary of actual monthly costs for the period for O&M Activities.
- Form 42-6A reflects the calculation of variances between actual and estimated/actual costs for Capital Investment Projects.
- Form 42-7A presents a summary of actual monthly costs for the period for Capital Investment Projects.
- Form 42-8A consists of the calculation of depreciation expense and return on capital investment. Form 42-8A, Pages 33 through 37 provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each Capital Investment Project.

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

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

Q. Please explain the calculation of the Net True-up Amount.

A. Form 42-1A, entitled "Calculation of the Final True-up" shows the calculation of the Net True-Up for the period January 2005 through December 2005, an over-recovery of $2,642,893, which I am requesting to be included in the calculation of the ECR factors for the January through December 2007 period.

The actual End-of-Period over-recovery for the period January through December 2005 of $7,061,106 (shown on Form 42-1A, line 3) adjusted for the estimated/actual End-of-Period over-recovery for the same period of $4,418,213 (shown on Form 42-1A, line 6) results in the Net True-Up over-recovery for the period January through December 2005 (shown on Form 42-1A, line 7) of $2,642,893.

Q. Have you provided a schedule showing the calculation of the End-of-

Period true-up?

A. Yes. Form 42-2A, entitled "Calculation of Final True-up Amount", shows the calculation of the Environmental End of Period true-up for the period January through December 2005. The End of Period true-up shown on page 2 of 2, Lines 5 plus 6 is an over-recovery of $7,061,106. Additionally, Form 42-3A shows the calculation of the Interest Provision of $148,030, which is applicable to end of period true-up over-recovery of $7,061,106.

Q. Is the true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by the Commission as set forth on Commission Schedule A-2 "Calculation of the True-Up and Interest Provisions" for the Fuel Cost Recovery Clause.

Q. Are all costs listed in Forms 42-4A through 42-8A attributable to Environmental Compliance Projects approved by the Commission?

A. Yes, they are.

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

A. Form 42-4A shows that total O&M project costs were $2,381,005, or 35.8% lower than projected and Form 42-6A shows that total capital investment project costs were $122,287 or 0.9% lower than projected. Following are explanations for those O&M Projects and Capital Investment Projects with significant variances. Individual project variances are provided on Forms 42-4A and 42-6A. Return on Capital Investment, Depreciation and Taxes for each project for the actual period January through December 2005 are provided on Form 42-8A.

1. Continuous Emission Monitoring Systems (CEMS) - O & M (Project 3a)

Project expenditures were $55,249, or 8.2% lower than previously projected, primarily due to fewer than expected purchases of CEMS spare parts and less than expected maintenance expense for the remainder of the year. A combination of new plant fleet additions (Manatee Unit 3 and Martin Unit 8) which come with equipment warranties, and less run time for older units (Cutler and Sanford Unit 3) led to fewer failures and less calibration gas usage at the older sites.

2. Resource Conservation and Recovery Act (RCRA) Corrective Action - O&M (Project 13)

Project expenditures were $33,680, or 35.4% lower than previously projected. Clean-up activities were deferred to 2006 due to hurricane recovery, and the Florida Department of Environmental Protection (FDEP) requested that its site visit for the Sanford Plant be postponed until after the end of the 2005 hurricane season. In addition, preparation activities for the Sanford Plant site visit, which were completed before the FDEP requested that the site visit be postponed, were performed in-house rather than by an outside contractor as previously planned.

3. Disposal of Non-containerized Liquid Waste – O & M (Project 17a)

Project expenditures were $37,298, or 15.5% lower than previously projected. Ash pond repairs were performed at the Manatee Plant, which deferred project work that had been scheduled for 2005. Additionally, ash removal at the Riviera and Sanford plants has been deferred until 2006 due to the low quality of existing ash in the accumulation ponds.

4. Substation Pollutant Discharge Prevention & Removal – Distribution - O&M (Project 19a)

Project expenditures were $110,356, or 14.4% lower than anticipated. Money was diverted from Project 19a to Project 19b as difficult clearances that FPL had been attempting to secure for several years became available and allowed for pollutant discharge and removal work at transmission facilities. Distribution-related work was deferred to 2006.

5. Substation Pollutant Discharge Prevention & Removal - Transmission - O&M (Project 19b)

Project expenditures were $106,874, or 28.7% higher than anticipated. As described in the above variance explanation, money was diverted to this project as difficult clearances for transmission facilities became available.

6. Amortization of Gains on Sales of Emission Allowances – O&M

The variance of $82,619, or 5.3% higher than projected, is primarily due to higher than anticipated sale prices for emission allowances sold in 2005.

7. Spill Prevention, Control, and Countermeasures (SPCC) – O&M (Project 23)

Project expenditures were $54,252, or 11.5% lower than previously projected. The Environmental Protection Agency (EPA) has issued rule changes and extended the due date for completion of the SPCC Plans from February 2006 to October 2007. The result of the date change is that more of the work will be performed in 2006 than originally anticipated. Additionally, planned diversionary structure design and construction for Service Centers was deferred for re-evaluation due to an anticipated EPA SPCC amendment which is expected to offer other compliance alternatives. Work on the remaining substation curbing portion of this project was deferred due to hurricane restoration.

8. Port Everglades Precipitator (ESP) – O & M (Project 25)

Project expenditures were $199,637, or 43.3% lower than previously projected, primarily due to favorable experience with operation and maintenance of the newly constructed electrostatic precipitators on Units 1 and 2 in comparison to FPL's projections. FPL had no prior experience with the new electrostatic precipitators at the time the projections were made, but expects to be able to refine its projections as it gains experience.

9. UST Replacement/Removal – O&M (Project 26)

Project expenditures were $83,949, or 76.3% lower than projected. The tank replacement engineering and design fieldwork at the Area Office - Broward and Customer Service East Office were delayed due to CRE Project Managers' support of facilities restoration work related to the 2005 hurricanes.

10. Lowest Quality Water Source (LQWS) – O&M (Project 27)

Project expenditures were $34,258, or 11.3% lower than previously projected. The Wastewater Permit for the Cape Canaveral Plant was issued by the FDEP. However, there were delays due to water quality technical issues associated with the treatment systems. Permit compliance requires a consistent quality of reclaimed water for use at the plant.

11. CWA 316(b) Phase II Rule – O&M (Project 28)

Project expenditures were $1,319,569, or 75.5% lower than previously projected. As a result of the hurricanes in 2005 and the time spent finding and hiring a qualified candidate for the Project Coordinator position, biological sampling at multiple plants was delayed. Consequently, the bulk of the biological sampling will now be conducted in 2006 and early 2007. Additionally, FPL's Proposal for Information Collection submittals to the FDEP take the position that no sampling is required at the Sanford or Lauderdale plants and that reduced sampling may be used at three other plants to meet the 316(b) Phase II Rule requirements. These changes to the sampling program have reduced the actual sampling cost.

12. Selective Catalytic Reduction (SRC) Consumables – O & M (Project 29)

Project expenditures were $196,220, or 69.6% lower than previously projected. The cost of anhydrous ammonia fluctuates according to operating conditions and commodity pricing. Original estimates were based on a commodity price of $0.28 per pound. The 2005 price for ammonia was $0.17 per pound and the plants used approximately 50% of estimated amounts. Additionally, equipment replacement costs were estimated for five years and averaged over the period. During the beginning of the five year period, replacement costs have been much less due to age of equipment and warranty claims.

13. Manatee Hydro-biological Monitoring Program (HBMP) – O & M (Project 30)

Project expenditures were $8,660 or 50.1% lower than previously projected. Due to the delay in the commercial operation of the plant and contractor activities being ahead of schedule, more costs were charged to project construction. Additionally, actual contractor costs were lower than expected.

14. Clean Air Interstate Rule (CAIR) Compliance – O & M (Project 31)

Project expenditures were $289,881, or 89.6% lower than expected. CAIR related legal expenses incurred in 2005 were charged to a non-recoverable account pending receipt of the Commission Order approving CAIR litigation expenses. These charges were transferred from a non-recoverable account to an ECRC recoverable account in 2006.

15. Spill Prevention, Control, and Countermeasures (SPCC) – Capital (Project 23)

Project depreciation and return on investment were $22,092, or 1.2% lower than anticipated. The EPA's timeframe for diversionary structure (curbing) installation has been extended from August, 2006 until October, 2007. Planned diversionary structure design and construction for Service

Centers was deferred for re-evaluation due to an anticipated EPA SPCC amendment which is expected to offer other compliance alternatives. Work on the remaining substation curbing portion of this project was deferred due to hurricane restoration.

16. Port Everglades Electrostatic Precipitator (ESP) Technology – Capital (Project 25)

Project depreciation and return on investment were $74,742, or 1.8% lower than anticipated. This variance is primarily due to timing differences – a larger portion of the project expenditures for Units 3 and 4 will occur later in the project than originally planned. The timing difference is primarily attributable to the original annual budget for ESP project being based on estimated monthly commitment projections. Actual purchase order negotiations with vendors performing activities on the project, based on a more definitive project schedule, resulted in the deferral of some project work scope originally planned for 2005 into 2006 and 2007.

17. UST Replacement / Removal – Capital (Project 26)

Project depreciation and return on investment were $1,061, or 100% lower than anticipated. The tank replacement engineering and design fieldwork at the Area Office - Broward and Customer Service East Office were delayed due to CRE Project Managers' support of facilities restoration work related to the 2005 hurricanes.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 060007-EI

August 4, 2006

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Regulatory Issues in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review and approval the Estimated/Actual True-up Costs associated with FPL Environmental Compliance activities for the period January 2006 through December 2006.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes, I have. The exhibit consists of eight documents, PSC Forms 42-1E through 42-8E, included in Appendix I. Form 42-1E provides a summary of the Estimated/Actual True-up amount for the period January 2006 through December 2006. Forms 42-2E and 42-3E reflect the calculation of the Estimated/Actual True-up amount for the period. Forms 42-4E and 42-6E reflect the Estimated/Actual O&M and Capital cost variances as compared to original projections for the period. Forms 42-5E and 42-7E reflect jurisdictional recoverable O&M and Capital project costs for the period. Form 42-8E (pages 1 through 40) reflects return on capital investments, depreciation, and taxes by project.

Q. Please explain the calculation of the ECRC Estimated/Actual True-up amount you are requesting this Commission to approve.

A. Forms 42-2E and 42-3E show the calculation of the ECRC Estimated/Actual True-up amount. The calculation for the Estimated/Actual True-up amount for the period January 2006 through December 2006 is an overrecovery, including interest, of $13,409,744 (Appendix I, Page 4, line 5 plus line 6). This Estimated/Actual True-up overrecovery of $13,409,744 consists of January through June 2006 actuals and revised estimates for July through December 2006, compared to original projections for the same period.

Q. Are all costs listed in Forms 42-1E through 42-8E attributable to Environmental Compliance projects previously approved by the Commission?

A. Yes, with the exception of the Clean Air Mercury Rule (CAMR) Compliance Project, which is discussed and supported in the testimony of Randall R. LaBauve. Additionally, Mr. LaBauve's testimony provides an update to FPL's approved Clean Air Interstate Rule (CAIR) Compliance Project.

Q. How do the Estimated/Actual project expenditures for January 2006 through December 2006 period compare with original projections?

A. Form 42-4E (Appendix I, Page 7) shows that total O&M project costs were $10,849,448 or 88.3% lower than projected and Form 42-6E (Appendix I, Page 10) shows that total capital investment project costs were $2,286,691 or 11.8% lower than projected. Below are variance explanations for those O&M Projects and Capital Investment Projects with significant variances. Individual project variances are provided on Forms 42-4E and 42-6E. Return on Capital Investment, Depreciation and Taxes for each project for the Estimated/Actual period are provided as Form 42-8E (Appendix I, Pages 13 through 52).

1. Maintenance of Stationary Above Ground Fuel Storage Tanks (Project No. 5a) - O&M

Project expenditures are estimated to be $861,641 or 222.9% higher than previously projected. This project includes performing required repairs identified during tank inspections. Based on the results of inspections performed during this period, higher than expected costs associated with repairs to Tank 802 and the Metering Tank at the Port Everglades Plant, and Tanks A and D at the Riviera Plant were incurred. Repairs at the Port Everglades Plant included repairs on 20 areas of the tank bottom and the removal and disposal of 60% more sludge than anticipated. Repairs at the Riviera Plant included repairs on the chime of the tanks, hydrotesting, and repairs due to severe roof corrosion on the tanks.

2. Disposal of Noncontainerized Liquid Waste (Project No. 17a) - O&M

Project expenditures are estimated to be $111,338 or 41.4% higher than previously projected. The variance is primarily due to the complete refurbishing of the dewatering filter press. The dewatering filter press is used to prepare fly ash slurry for either disposal or recycling.

3. Substation Pollutant Discharge Prevention & Removal – Distribution (Project No. 19a) - O&M

Project expenditures are estimated to be $386,220 or 28.6% lower than projected. The project vendor contract was put out for bid and not formalized until late March, 2006. This resulted in a reduction in the units completed, but produced favorable pricing, further reducing distribution costs going forward.

4. Substation Pollutant Discharge Prevention & Removal – Transmission (Project No. 19b) - O&M

Project expenditures are estimated to be $68,242, or 59.4% higher than projected. Storm events produced additional carry-over work activities from 2005; this resulted in an increased workload for transmission related activities in 2006.

5. Amortization of Gains on Sales of Emissions Allowances – O&M

The variance of $7,827,444 or 775.8% higher than projected is primarily due to FPL swapping 2006 vintage year allowances for future vintage year allowances. Since the 2006 allowances are worth more than the future allowances, FPL realized deferred gains in February and March of $2,850,380 and $3,900,000, respectively which will be fully amortized in 2006.

6. Pipeline Integrity Management – Distribution (Project No. 22) - O&M

Project expenditures are estimated to be $149,631 or 62.3% higher than projected. The variance is primarily due to additional confirmatory digs on the Manatee 16" and Martin 18" pipelines which were required based on the results of the initial confirmatory digs at these sites.

7. Spill Prevention, Control, and Countermeasures - SPCC (Project No. 23) - O&M

Project expenditures are estimated to be $363,243 or 261.1% higher than projected. The Environmental Protection Agency (EPA) extended the deadlines for SPCC compliance. This resulted in a shift into 2006 of work activities that were scheduled to be performed during late 2005.

8. Manatee Reburn (Project No. 24) - O&M

Project expenditures are estimated to be $210,000. Projected O&M costs associated with this project were inadvertently excluded from the 2006 projection filing.

9. Port Everglades Electrostatic Precipitator – ESP (Project No. 25) - O&M

Project expenditures are estimated to be $1,116,226 or 60.7% lower than projected. FPL was able to have projected maintenance work on the ESPs performed under warranty and thus reduced the cost of that work to FPL and its customers. Additionally, fuel economics to date have dictated that the units at the Port Everglades Plant be run on gas because it is less expensive. Therefore, the ESPs have not had to be operated as initially predicted for 2006, which reduced the equipment deterioration and generated significantly less ash for disposal.

10. Underground Storage Tank (UST) Replacement/Removal (Project No. 26) - O&M

Project expenditures are estimated to be $96,786 or 38.2% higher than projected primarily due to significantly higher than projected costs of tanks, concrete, and other materials. Additionally, tank projects were rescheduled from 2005 to 2006 due to last year's storm restoration activities.

11. Lowest Quality Water Source - LQWS (Project No. 27) – O&M

The variance of $61,615 or 16.0% lower than projected is primarily due to a delay in the issuance of the Wastewater Permit from the Florida Department of Environmental Protection (FDEP) for the Cape Canaveral Plant.

12. CWA 316(b) Phase II Rule (Project No. 28) – O&M

Project expenditures are estimated to be $3,335,354 or 66.8% lower than projected. The original projection was based on the assumption that biological sampling was necessary at seven power plants as well as the expectation of significant engineering costs during the development of the Comprehensive Demonstration Study (CDS).

The development of FPL's compliance strategy at the Sanford and Fort

Lauderdale Plants eliminated the need for biological sampling and significantly reduced the sampling required at the Fort Myers Plant. Additionally, this compliance strategy reduced the level of contractor support that was needed for engineering in the CDS development for these plants.

13. Selective Catalytic Reduction (SCR) Consumables (Project No. 29) – O&M

Project expenditures are estimated to be $385,380 or 66.0% lower than projected. The cost of anhydrous ammonia fluctuates according to operating conditions and commodity pricing. Original estimates were based on a commodity price of $0.28 per pound. The current price of ammonia is $0.19 per pound.

14. CAIR Compliance Project (Project No. 31) – O&M

Project expenditures are estimated to be $436,163 or 261.5% higher than projected. CAIR legal expenses incurred in 2005 were charged to a non-recoverable account pending receipt of the Commission Order approving CAIR litigation expenses. These charges were transferred from a non-recoverable account to an ECRC recoverable account in 2006. FPL's original projections for 2006 did not reflect this transfer.

15. Low NOx Burner Technology (Project No. 2) - Capital

The variance in depreciation and return is $758,059 or 43.2% lower than projected. The variance is primarily due to the retirement of equipment at Port Everglades Unit 2 and Turkey Point Unit 1 which was not originally anticipated.

16. Continuous Emission Monitoring Systems - CEMS (Project No. 3b) - Capital

The variance in depreciation and return is $370,887 or 25.3% lower than projected. This variance is primarily due to delays in the implementation of the Fleet wide CO2 Analyzer replacement Project in 2006. FPL is currently evaluating two manufacturers' CO2 Analyzer products, which has delayed the Project. The Project is currently planned for the 2007/2008 budget years.

17. Clean Closure Equivalency (Project No. 4b) - Capital

The variance in depreciation and return is $1,508 or 25.9% lower than projected. This variance is due to the change in depreciation rates in 2006 as a result of FPL's Stipulation and Settlement Agreement dated August 22, 2005. Although this change affected all capital projects, the Clean Closure Equivalency Project had no other activity and therefore this change was the sole reason for its variance. In turn, this has made the percentage impact of the depreciation rate change on this Project's cost projections appear more substantial than for other projects.

18. Relocate Turbine – Lube Oil Underground Piping to Above

Ground (Project No. 7) - Capital

The variance in depreciation and return is $1,372 or 44.4% lower than projected. This variance is due to a change in the depreciation rates in 2006 as a result of FPL's Stipulation and Settlement Agreement dated August 22, 2005. Although this change affected all capital projects, the Relocate Turbine – Lube Oil Underground Piping to Above Ground Project had no other activity and therefore this change was the sole reason for its variance. In turn, this has made the percentage impact of the depreciation rate change on this Project's cost projections appear more substantial than for other projects.

19. SO2 Allowances – Negative Return on Investment – Capital

The variance of $348,355 or 134.5% higher than projected is primarily due to FPL swapping 2006 vintage year allowances for future vintage year allowances. Since the 2006 allowances are worth more than the future allowances, FPL realized deferred gains in February and March of $2,850,380 and $3,900,000, respectively which will be fully amortized in 2006. The increase in the negative return relates to capital costs of the unamortized balance of the gains during 2006.

20. Scherer Discharge Pipeline (Project No. 12) - Capital

The variance in depreciation and return is $21,348 or 23.6% lower than projected. This variance is due to the change in depreciation rates in 2006 as a result of FPL's Stipulation and Settlement Agreement dated August 22, 2005. Although this change affected all capital projects, the Scherer Discharge Pipeline Project had no other activity and therefore this change was the sole reason for its variance. In turn, this has made the percentage impact of the depreciation rate change on this Project's cost projections appear more substantial than for other projects.

21. Pipeline Integrity Management (Project No. 22) - Capital

The variance in depreciation and return is $29,358 or 100% lower than projected. The leak detection system on the Martin 30" pipeline has been deferred, thus no expenditures were made.

22. Spill Prevention, Control, and Countermeasures - SPCC (Project No. 23) - Capital

The variance in depreciation and return is $191,907 or 8.8% lower than projected. While the project is currently running under budget, assessments will continue during the remainder of the year and additional improvements will likely be identified and completed. This should bring the total for 2006 closer to the originally anticipated budget.

23. Manatee Reburn (Project No. 24) - Capital

The variance in depreciation and return is estimated to be $609,484 or 18.6% higher than projected. This variance is due to delays in the outage schedule and mechanical drawing design changes which have pushed equipment installation out until to 2006.

24. Pt. Everglades Electrostatic Precipitator (ESP) Technology (Project No. 25) - Capital

The variance in depreciation and return is estimated to be $922,944 or 11.5% lower than projected. The variance is primarily due to a more refined scope definition and the award of lump sum contracts that resulted in more accurate estimates for the project.

25. UST Replacement/Removal (Project No. 26) - Capital

The variance in depreciation and return is estimated to be $10,759 or 28.9% lower than projected. This variance is primarily due to the change in depreciation rates in 2006 as a result of FPL's Stipulation and Settlement Agreement dated August 22, 2005.

26. Clean Air Interstate Rule (CAIR) Compliance (Project No. 31) - Capital

The variance in the return on CWIP is estimated to be $284,855 or 57.5% lower than projected. This variance is due to delays in the payments to consultants related to Phase I engineering studies. Payments have been deferred until 2007.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 060007-EI

SEPTEMBER 1, 2006

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Regulatory Issues in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review FPL's Environmental Cost Recovery Clause (ECRC) projections for the January 2007 through December 2007 period.

Q. Is this filing by FPL in compliance with Order No. PSC-93-1580-FOF-EI, issued in Docket No. 930661-EI?

A. Yes. The costs being submitted for the projected period are consistent with that order.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes. KMD-3 consists of seven documents, PSC Forms 42-1P through 42-7P provided in Appendix I. Form 42-1P summarizes the costs being presented at this time. Form 42-2P reflects the total jurisdictional costs for O&M activities. Form 42-3P reflects the total jurisdictional costs for capital investment projects. Form 42-4P consists of the calculation of depreciation expense and return on capital investment for each project. Form 42-5P gives the description and progress of environmental compliance activities and projects for the projected period. Form 42-6P reflects the calculation of the energy and demand allocation percentages by rate class. Form 42-7P reflects the calculation of the ECRC factors.

Q. Please describe Form 42-1P.

A. Form 42-1P (Appendix I, Page 2) provides a summary of projected environmental costs being presented for the period January 2007 through December 2007. Total environmental costs, adjusted for revenue taxes, amount to $25,393,473 (Appendix I, Page 2, Line 5a) and include

$41,427,840 of environmental project costs (Appendix I, Page 2, Line 1c) decreased by the estimated/actual true-up over-recovery of $13,409,744 for the January 2006 - December 2006 (Appendix I, Page 2, Line 2), and decreased by the final true-up over-recovery of $2,642,893 for the January 2005 – December 2005 period (Appendix I, Page 2, Line 3).

Q. Please describe Forms 42-2P and 42-3P.

A. Form 42-2P (Appendix I, Pages 3 and 4) presents the environmental project O&M costs for the projected period along with the calculation of total jurisdictional costs for these projects, classified by energy and demand. Form 42-3P (Appendix I, Pages 5 and 6) presents the environmental project capital investment costs for the projected period. Form 42-3P also provides the calculation of total jurisdictional costs for these projects, classified by energy and demand.

The method of classifying costs presented in Forms 42-2P and 42-3P is consistent with Order No. PSC-94-0393-FOF-EI for all projects.

Q. Please describe Form 42-4P.

A. Form 42-4P (Appendix I, Pages 7 through 47) presents the calculation of depreciation expense and return on capital investment for each project for the projected period.

Q. Please describe Form 42-5P.

A. Form 42-5P (Appendix I, Pages 48 through 84) provides the description and progress of environmental projects included in the projected period.

Q. Please describe Form 42-6P.

A. Form 42-6P (Appendix I, Page 85) calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

Q. Please describe Form 42-7P.

A. Form 42-7P (Appendix I, Page 86) presents the calculation of the proposed ECRC factors by rate class.

Q. Are all costs listed in Forms 42-1P through 42-7P attributable to Environmental Compliance projects previously approved by the Commission?

A. Yes, with the exception of the Clean Air Mercury (CAMR) Compliance Project. The CAMR Compliance Project was presented in the testimony of R. R. LaBauve filed on August 4, 2006, and FPL petitioned for Commission approval of that project in its 2006 ECRC estimated/actual true up petition that was filed on that date.

Additionally, Mr. LaBauve's testimony included in this filing presents for review and approval the inclusion of Turkey Point Unit 5 as part of FPL's previously approved Selective Catalytic Reduction (SCR) Consumables Project.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 060007-EI

SEPTEMBER 1, 2006

(REVISED OCTOBER 13, 2006)

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Regulatory Issues in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review FPL's Environmental Cost Recovery Clause (ECRC) projections for the January 2007 through December 2007 period.

Q. Is this filing by FPL in compliance with Order No. PSC-93-1580-FOF-EI, issued in Docket No. 930661-EI?

A. Yes. The costs being submitted for the projected period are consistent with that order.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes. KMD-3 consists of seven documents, PSC Forms 42-1P through 42-7P provided in Appendix I. Form 42-1P summarizes the costs being presented at this time. Form 42-2P reflects the total jurisdictional costs for O&M activities. Form 42-3P reflects the total jurisdictional costs for capital investment projects. Form 42-4P consists of the calculation of depreciation expense and return on capital investment for each project. Form 42-5P gives the description and progress of environmental compliance activities and projects for the projected period. Form 42-6P reflects the calculation of the energy and demand allocation percentages by rate class. Form 42-7P reflects the calculation of the ECRC factors.

Q. Please describe Form 42-1P.

A. Form 42-1P (Appendix I, Page 2) provides a summary of projected environmental costs being presented for the period January 2007 through December 2007. Total environmental costs, adjusted for revenue taxes, amount to $24,653,514 (Appendix I, Page 2, Line 5a) and include

$40,688,413 of environmental project costs (Appendix I, Page 2, Line 1c) decreased by the estimated/actual true-up over-recovery of $13,409,744 for the January 2006 - December 2006 (Appendix I, Page 2, Line 2), and decreased by the final true-up over-recovery of $2,642,893 for the January 2005 – December 2005 period (Appendix I, Page 2, Line 3).

Q. Please describe Forms 42-2P and 42-3P.

A. Form 42-2P (Appendix I, Pages 3 and 4) presents the environmental project O&M costs for the projected period along with the calculation of total jurisdictional costs for these projects, classified by energy and demand. Form 42-3P (Appendix I, Pages 5 and 6) presents the environmental project capital investment costs for the projected period. Form 42-3P also provides the calculation of total jurisdictional costs for these projects, classified by energy and demand.

The method of classifying costs presented in Forms 42-2P and 42-3P is consistent with Order No. PSC-94-0393-FOF-EI for all projects.

Q. Please describe Form 42-4P.

A. Form 42-4P (Appendix I, Pages 7 through 47) presents the calculation of depreciation expense and return on capital investment for each project for the projected period.

Q. Please describe Form 42-5P.

A. Form 42-5P (Appendix I, Pages 48 through 84) provides the description and progress of environmental projects included in the projected period.

Q. Please describe Form 42-6P.

A. Form 42-6P (Appendix I, Page 85) calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

Q. Please describe Form 42-7P.

A. Form 42-7P (Appendix I, Page 86) presents the calculation of the proposed ECRC factors by rate class.

Q. Are all costs listed in Forms 42-1P through 42-7P attributable to Environmental Compliance projects previously approved by the Commission?

A. Yes, with the exception of the Clean Air Mercury (CAMR) Compliance Project. The CAMR Compliance Project was presented in the testimony of R. R. LaBauve filed on August 4, 2006, and FPL petitioned for Commission approval of that project in its 2006 ECRC estimated/actual true up petition that was filed on that date.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 060007-EI

August 4, 2006

Q. Please state your name and address.

A. My name is Randall R. LaBauve and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Vice President of Environmental Services.

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review and approval the Clean Air Mercury Rule (CAMR) Compliance Project and to provide an update of FPL's Clean Air Interstate Rule (CAIR) Project, which was approved by the Commission in Order No. PSC-05-1251-FOF-EI, issued on December 22, 2005 in Docket 050007-EI.

Q. Have you prepared, or caused to be prepared under your direction, supervision, or control, an exhibit in this proceeding?

A. Yes. It consists of the following documents:

- Document RRL-1 – U.S. Environmental Protection Agency - Clean Air Mercury Rule – Regulatory Text
- Document RRL-2 – Department of Environmental Protection – Clean Air Mercury Rule as proposed to the Environmental Regulation Commission – Chapters 62-204, 62-210, 62-296, FAC
- Document RRL-3 – Department of Environmental Protection – Clean Air Interstate Rule as proposed to the Environmental Regulation Commission – Chapters 62-204, 62-210, 62-296, FAC
- Document RRL-4 – Clean Air Interstate Rule and Clean Air Mercury Rule State Notices of change in the Florida Administrative Weekly – pp.5-8, published July 21, 2006 – changes by the Environmental Regulation Commission

CAMR COMPLIANCE PROJECT

Q. Please describe the law or regulation requiring this activity.

A. The Clean Air Mercury Rule (CAMR) was promulgated by the Environmental Protection Agency (EPA) on May 18, 2005. It imposes nation-wide standards of performance for mercury (Hg) emissions from existing and new coal-fired electric utility steam generating units. CAMR is designed to reduce emissions of Hg from coal-fired electric generating units. Compliance with CAMR may be achieved in three ways:

1) the addition of specific mercury reduction control equipment;
2) co-benefits reduction of Hg through the use of control equipment installed to meet the Clean Air Interstate Rule or other Clean Air Act requirements that also control Hg; and/or
3) purchases of allowances through a cap and trade market, similar to the Title IV Cap and Trade Program for SO2 allowances. Hg allowances are traded in ounces.

In addition, CAMR requires the installation of Hg Continuous Emission Monitoring Systems (HgCEMS) to monitor compliance with the emission requirements. The rule is implemented in two phases with an initial compliance date of 2010 for Phase I and a Phase II reduction requirement in 2018.

Q. Please describe the Hg emissions from coal-fired plants and the control technologies available to reduce those emissions.

A. During combustion, mercury present in the coal becomes volatilized within the flue gas. Two forms of mercury are typically present in coal fired flue gas: Elemental Mercury (Hg0) and Ionized Mercury (Hg++). Research and field applications have shown that wet Flue Gas

Desulfurization (FGD) installed to remove sulfur dioxide (SO2) is highly effective in removing the ionized form of Hg from the flue gas of electric generating units (EGUs) burning Eastern Bituminous Coals. A Selective Catalytic Reduction System (SCR), which is located upstream of the FGD, removes additional Hg by facilitating the ionization of the elemental mercury (Hg0), making it more readily available for capture in the scrubber.

The choice of the specific technology applied to each EGU requires consideration of six major factors: 1) type of coal combusted in each unit; 2) existing installed control equipment; 3) unit specific design parameters and control option feasibility; 4) control equipment reagent use and by-product disposal requirements; 5) existing or proposed air quality regulations and rules; 6) availability and robustness of an emissions allowance market.

The Phase I and Phase II reductions required by CAMR were derived through the evaluation of applying suitable control technology to coal-fired EGUs. The majority of the reductions anticipated for Phase I compliance are expected to occur as the result of the "co-benefits" I described above.

The Phase II Hg reductions required by CAMR will likely require the installation of Hg-specific controls to achieve the emissions limits. Hg controls for coal-fired EGUs have generally not been in use within the U.S.; however, these technologies have been extensively utilized in Municipal Waste Incinerator Combustion units and on EGUs in other countries. Controls used on these units typically involve the injection of a sorbent material to capture the Hg, such as activated carbon, and a collection device, typically a fabric filter or baghouse. The Hg in the flue gas chemically binds to active sites on the sorbent and is captured with the sorbent in the collection device.

Q. What is the status of Florida's and Georgia's implementation of CAMR?

A. On June 29, 2006, Florida's Environmental Regulation Commission (ERC) approved the Florida Department of Environmental Protection's (DEP) proposed rule to implement the CAMR reduction requirements for coal-fired plants in Florida. The DEP's rule includes options for unit-specific emissions limits on Hg emissions from coal fired generating units, the use of co-benefits reductions, and participation in the EPA's model rule cap and trade program. The rule provides a five percent set-aside of emissions allowances for new units. In addition, and different from the EPA model rule, there is a 25% "hold back " account beginning in the year 2012 that is available only to new units or existing units that have installed co-benefits controls. Units 1 and 2 at the St. John's River Power Park (SJRPP) Plant in which FPL has a 20% ownership share, are CAMR-affected units and will require the installation of Hg controls and HgCEMs.

The Georgia Environmental Protection Division has also initiated rulemaking to implement CAMR, but that rulemaking is not yet complete. Once completed, the Georgia rule will affect Scherer Unit 4, in which FPL has a 75% ownership share. FPL expects that Scherer Unit 4 will require the installation of HgCEMS and Hg controls.

Q. How did FPL determine the cost effective compliance strategies for St. Johns River Power Park and Scherer Unit 4?

A. Together with our ownership partners, FPL has evaluated CAMR to determine the most appropriate Hg controls for each EGU. The first factor analyzed, which affected all FPL coal EGUs, was to determine the potential for an open market Hg allowance trading program in both Florida and Georgia, which would provide clear market signals of Hg allowance prices and availability. At this time, the prospects for such a program are not promising. Rulemaking in both Florida and Georgia has focused on either not participating in the federal cap and trade program for Hg and applying unit specific limits, or on limiting the allocation of allowances. The limited allowance allocation option, recently adopted by Florida, distributes only a portion of the allowances while the remaining allowances are placed in a "hold-back" account that can only be utilized by sources that have installed co-benefits controls and were not able to meet allocated emissions limits.

In this limited cap and trade approach, a unit which does not install controls will face a shortfall of allowances without the certainty that any excess allowances would be available for purchase in either Florida or other participating cap and trade states.

Furthermore, there is currently no established Hg trading market or a guarantee that excess allowances will be available to establish a viable market. It is anticipated that the rush to install pollution control equipment will place high demands on manpower and equipment availability. Some units may not complete the installation of their control systems until after the 2010 compliance date, thus few Hg allowances may be available for trade initially.

In summary, neither Florida nor Georgia is encouraging or facilitating reliance on allowances as a primary compliance option and there is substantial uncertainty over the development of a robust market for allowances. CAMR offers no amnesty for failure to comply either with emissions limits or the surrender of sufficient allowances to offset emissions. Given these conditions FPL has concluded that it must move forward with the design, engineering, procurement and installation of additional pollution control equipment at SJRPP to achieve co-benefit Hg control, and install Hg-specific control technology at Plant Scherer.

Q. Please describe the co-benefits and Hg control systems FPL Plans for SJRPP.

A. At SJRPP, FPL and our ownership partners have chosen the use of co-benefits controls for Hg removal as the lowest cost alternative for compliance with CAMR. These controls will also help the SJRPP units meet the requirements of CAIR. They include the use of the existing FGD scrubber system and the installation of new SCRs. Both SJRPP units currently burn Eastern Bituminous coals and Petroleum Coke as the primary fuels, and there are no plans at present for changes to the fuels being utilized at SJRPP. The high chloride content of the bituminous coals facilitates the capture of Hg in the FGD. Removal efficiency of the co-benefits approach is expected to provide sufficient Hg removal to comply with Phase I of CAMR. Following the installation of Hg monitoring equipment and the pending data to be received after co-benefits controls are in place, FPL will evaluate the need for additional controls to meet the 2018 Phase II compliance date.

Q. Please describe the Hg controls planned for Scherer Unit 4.

A. Scherer Unit 4 burns low sulfur, western Powder River Basin coal. FGD and SCR installations to meet CAIR compliance requirements will not be required until Phase II of CAIR; thus FPL plans to meet the Phase I CAMR Hg reduction requirements through the installation of Hg-specific removal controls. These include a sorbent injection system and fabric-filter baghouse. FPL has evaluated this option as the most cost-effective manner to meet the CAMR requirements for Scherer Unit 4. Other Hg-specific removal processes have been evaluated for this site including the installation of gold-plated catalysts to capture mercury, and a process that extracts elemental mercury, fertilizers and sulfuric acid as byproducts. These processes proved to be less economical than sorbent injection systems.

The planned sorbent injection system combined with a filter fabric baghouse has been determined to be the most cost effective Hg specific method to use for Scherer Unit 4. This methodology has been used successfully throughout the municipal solid waste incinerator industry, as well as in other countries on EGUs. The Toxicon method of injecting activated carbon into the late stages of the electrostatic precipitator was also considered feasible. However, this process results in excess particulate emissions that would trigger costly New Source Review requirements for additional particulate controls and subsequent parasitic load requirements on the unit.

FPL has not yet determined the most appropriate type of sorbent to utilize at Scherer Unit 4. Activated carbon is typically used for mercury removal at coal fired EGUs, but it has had limited success at EGUs firing Powder River Basin coal. Other currently available options include the use of amended silicates and halogenated (bromine or chlorine) sorbents. Once FPL and its co-owners have determined the most cost-effective sorbent to use at Scherer Unit 4, FPL will advise the Commission regarding specific O&M costs associated with the sorbents and the annual replacement of miscellaneous system parts including fabric filter bags.

FPL anticipates the future installation of SCR and FGD at Plant Scherer to comply with the CAIR Phase II requirements. The installation of these controls, in addition to the proposed sorbent injection and baghouse system that will be installed to meet Phase I of CAMR, should be sufficient to achieve compliance with the CAMR Phase II Hg reduction requirements.

Q. Please describe the CAMR monitoring requirements.

A. CAMR requires that coal fired electric generating units demonstrate compliance with the new 40 CFR Part 75 requirements for HgCEMS no later than January 1, 2009 for existing units. The HgCEMS must demonstrate compliance with the Part 75 certification requirements for accuracy and quality assurance and quality control by the applicable date.

Q. How does FPL plan to meet the CAMR monitoring requirements at SJRPP and Scherer Unit 4?

A. FPL plans to design, install, and certify the Hg CEMS at SJRPP Units 1 and 2 and Scherer Unit 4 prior to the January 1, 2009 deadline. Implementation of HgCEMS will require additional annual operating and maintenance costs to maintain compliance with the CAMR monitoring requirements once these HgCEMS begin operation.

Q. Has FPL estimated the cost of the proposed CAMR compliance Project?

A. FPL's preliminary Capital estimates for its share of the costs for installation of the HgCEMS at SJRPP 1 & 2 and Scherer Unit 4 are $696,000 for 2006 and $7.9 million for 2007. These estimates are for the design, installation and testing of the HgCEMS. The Hg CEMs will require significant lead time for testing and certification before the January 1, 2009 deadline, as they are only recently being made commercially available for the use in EGUs. Additionally, FPL will require several months of background Hg data in order to evaluate equipment removal efficiencies when pollution control equipment is installed. FPL has estimated its share of the total cost of CAMR compliance at Plant Scherer Unit 4 at $47,200,000 in capital upon completion of the Hg Controls project in 2010. As I have previously discussed, FPL expects to meet the CAMR requirements at SJRPP using co-benefits controls at least through the end of Phase I and then will evaluate whether any Hg-specific controls will be needed. Therefore, there are no separate control costs projected for SJRPP at this time other than the cost of the HgCEMs. Instead, FPL will include the costs of the SJRPP co-benefit controls for recovery in its CAIR Compliance Project.

Q. How will FPL ensure that the costs incurred are prudent and reasonable?

A. As is our standard practice with all equipment procurements, FPL will competitively bid the emissions control and HgCEMS in order to ensure the lowest overall cost to our customers.

Q. Is FPL recovering through any other mechanism the costs of the CAMR Compliance Project for which it is seeking ECRC recovery?

A. No.

<u>CAIR Compliance Project Update</u>

Q. Please explain the purpose of your testimony as it relates to the Clean Air Interstate Rule.

A. In Order No. PSC-05-1251-FOF-EI, issued on December 22, 2005 in Docket 050007-EI, the Commission found that the costs associated with complying with the new Clean Air Interstate Rule (CAIR) are eligible for recovery through the ECRC subject to the demonstration that costs for specific activities are reasonable and prudent. The

Commission also approved recovery through the ECRC of prudently incurred costs associated with FPL's legal challenge to CAIR. Specific CAIR compliance project costs approved for recovery in 2005 and 2006 included engineering studies to determine cost effective compliance measures for FPL's oil and gas fired steam EGUs, and preliminary and detailed engineering studies and the development of purchase/construction schedules for selective catalytic reduction equipment at St. Johns River Power Park Plant Units 1 and 2. The purpose of my testimony is to present for the Commission's review and approval an update on FPL's CAIR compliance activities.

Q. Please briefly review the Clean Air Intestate Rule and its application to FPL.

A. In May 2005 EPA published the CAIR to reduce downwind transport of ozone and PM2.5 into areas that failed to meet ambient air quality standards – "non-attainment areas." EPA included all of Florida in the compliance requirements of the rule for fine particulate (PM2.5) emissions due to modeled impacts on counties located in Alabama and Georgia; and for ozone emissions due to modeled impacts on one county in Georgia. In order to reduce ozone and PM2.5 impacts on those counties CAIR mandates include emissions reductions from EGUs of nitrogen oxides (NOx) and sulfur dioxide (SO2). The CAIR NOx emission reductions will be implemented in two phases, with the first phase in 2009 and the second phase in 2015. SO2 reductions under CAIR are also implemented in two phases, with Phase I beginning in 2010 followed by a Phase II reduction in 2015. EGUs are to be allocated a limited number of emission allowances, and CAIR contemplates a cap and trade system for those allowances similar to the current system under the Clean Air Act Title IV Acid Rain Program.

Q. Please briefly describe FPL's litigation regarding CAIR and provide a status update on that litigation.

A. Following the publication of EPA's final CAIR, FPL along with eight other electric generating companies in Florida formed the Florida Association of Electric Utilities (FAEU) and filed a petition with EPA for reconsideration of certain aspects of the rule. The FAEU contends that EPA erred in their inclusion of all of Florida in the ozone compliance requirements of CAIR; and that EPA also erred in their inclusion of plants in the southern half of Florida in the PM2.5 compliance requirements of CAIR. In addition to filing a petition with EPA for reconsideration, the FAEU also filed a petition with the DC Circuit Court for judicial review of the rule. At the same time as the FAEU filings, FPL Group separately filed for reconsideration by EPA and filed a petition with the DC Circuit Court seeking judicial review of CAIR. FPL's motion for reconsideration to EPA and petition for judicial review to the DC Circuit Court challenged the same issues of CAIR's applicability to Florida that were raised by the FAEU and also challenged EPA's use of fuel adjustment factors to allocate NOx emissions allowances. The fuel adjustment factors result in a reduction of NOx emissions allowance allocations to cleaner oil and gas fired generation so that coal-fired EGUs can receive a greater share of the allowances. FPL contends that the fuel adjustment factors are an unnecessary subsidy to coal fired generation at the expense of FPL's customers whose fossil fired generation depends primarily on oil and natural gas.

In response to the FAEU and FPL motions for reconsideration, EPA agreed to reconsider two issues relevant to FPL's CAIR challenge. EPA re-opened the CAIR rule docket and took additional comments on (1) whether Florida should be included in the ozone season compliance requirements of CAIR; and (2) the use of fuel adjustment factors to allocate NOx allowances. EPA's decision to reopen the rule docket for reconsideration offered FPL an opportunity to include emissions modeling data into the record regarding the effect of Florida emissions on downwind non-attainment areas. In April of 2006 EPA issued its Final Decision on Reconsideration, which declined to adopt any of the changes proposed in FPL's or any of the other motions for reconsideration that were received. Thus, FPL and FAEU have petitioned the DC Circuit for review of the EPA's reconsideration decision. FPL expects that all of the various appeals of CAIR and the reconsideration decision will be consolidated. Petitioner's arguments are expected to be briefed to the court in the Fall of 2006 with an expected decision from the court by the Fall of 2007.

Q. How is CAIR being implemented in Florida?

A. The DEP is in the process of promulgating rules to implement CAIR in Florida via amendments to the State Implementation Plan (SIP), which must be submitted to EPA for approval. On June 29, 2006 the ERC voted to adopt the DEP's proposed CAIR implementation rules. As it is doing in its challenge of EPA's rule, FPL takes exception to the DEP's inclusion of fuel adjustment factors for allocating NOx emission allowances. FPL has advised the DEP that the fuel adjustment factor provision of the CAIR implementation rule will cost FPL customers approximately $11-$25 million per year in additional NOx allowances. At the ERC's June 29 hearing, FPL proposed two amendments to the DEP's CAIR rules to eliminate the fuel adjustment factors; however the ERC was unwilling to adopt these amendments. FPL is presently considering whether to challenge the DEP's CAIR implementation rule

Q. What is the status of FPL's compliance planning process for CAIR?

A. CAIR includes both annual and ozone season NOx allowance allocation limits. Under CAIR as presently written, Florida receives 99,445 annual NOx allowances in Phase I and 82,871 annual NOx allowances in Phase II. The ozone season is the period between May and September when emissions of NO_x and SO_2 are expected to contribute more to the formation of downwind ozone and smog. Florida's estimated NO_x ozone season allowance allocation under CAIR will be approximately 48,000 tons of allowances in Phase I and 39,000 tons of allowances in Phase II.

Florida's NO_x allowances will be allocated to individual EGUs by the DEP. Under DEP's CAIR implementation rule as presently written, FPL estimates that its affected units will be allocated approximately 20,500 annual NO_x allowances and 10,500 NO_x ozone season allowances in Phase I of CAIR. This will leave FPL's EGUs short an average of 11,500 tons of annual NO_x allowances and 7,500 tons of ozone season allowances in Phase I.

Q. Please describe how FPL determined the most cost effective approach for CAIR compliance.

A. Following the PSC's approval of engineering evaluation studies to determine the most cost effective compliance approach to CAIR, FPL commissioned Black & Veatch Energy to evaluate FPL's generating units, projected operation and emissions to determine the most cost effective options for complying with the CAIR. The engineering analysis focused on an assessment of the NO_x and SO_2 emissions reduction strategies available for implementation. The goal of the analysis was to develop the most cost effective long term compliance strategy and implementation plan for complying with CAIR while taking into consideration the NOx and SO2 allowance allocations available to FPL and the estimated future NOx and SO2 allowance prices.

Control technologies evaluated in the analysis included:

- Combustion Control Technologies for NOx
  - Low NOx Burner
  - Overfire Air
  - Neural Network
  - Oil Reburn with Low NOx Burners
  - Induced Flue Gas Recirculation
  - COOLfuel w/steam Atomizers
- Post Combustion Control Technologies for NOx
  - Selective Non-Catalytic reduction (SNCR)
  - Selective Catalytic Reduction (SCR)
  - SCONOX™ Catalytic Absorption System
  - SNCR/SCR Hybrid (Cascade)
- SO2 Removal Technologies
  - Furnace or Duct Reagent Injection
  - Wet Limestone Spray Tower Flue Gas Desulfurization (FGD) and a new stack
  - Wet Limestone Contact FGD and a new stack
  - Semi-dry Lime FGD and electrostatic precipitator (ESP)

Emissions control technology equipment costs were evaluated for the affected EGUs, and compliance scenarios to achieve the required emissions reductions were developed. In addition to pollution control equipment costs and scenarios, a projection of future NOx and SO2 allowance prices and allowance allocations from the DEP was performed. Black & Veatch also utilized an optimization tool to model the compliance scenarios developed and to summarize emissions reductions and costs. The optimization tool assists in identifying the most economical method to achieve compliance. Emissions reduction scenarios were compared to NOx and SO2 emissions allowance price projections:

CAIR Allowance Price Projections

Year	NOx Allowance Price, $/ton	SO2 Allowance Price, $/ton
2009	3,474	700
2010	3,561	1,061
2015	5,091	1,645

Source: Black & Veatch Energy, 2006

Compliance scenarios that cost less than the projected allowance price on a $/ton removed basis were determined to be viable for implementation.

Q. What has FPL determined to be the most cost effective approaches to complying with CAIR?

A. Based on the Black & Veatch engineering evaluation FPL has concluded that NOx emissions control technologies utilizing Low NOx Burners and Reburn Technology combined with NOx emissions allowance purchases will be the most cost effective approach to meet the CAIR NOx emissions requirements at FPL's fossil fired generating facilities. The utilization of Low Nox Burners combined with Reburn Technology was estimated by Black & Veatch to cost approximately $1,000/ton of NOx removed.

The NOx emissions control technology is planned to be installed at FPL's Cape Canaveral Units 1 & 2, Port Everglades Units 3 & 4, and Turkey Point Fossil Units 1 and 2. Design, engineering and procurement of these controls are scheduled to begin in September 2006. Utilizing existing scheduled outages for the affected units, construction of the pollution control equipment will begin in 2007. The majority of the construction and installation of these controls will occur between 2007 and 2009. Although Martin Plant Units 1 and 2 have previously been approved for the installation of reburn technology, FPL's engineering analysis and unit outage schedule have determined that additional control equipment is not currently required at the Martin Plant.

NOx allowances, as needed, will be used to offset any additional emissions. When available FPL will utilize excess NOx allowances from other FPL facilities, such as the St. Johns River Power Park, or will purchase allowances from the open trading market. FPL is also evaluating the installation of pollution control equipment on the remaining oil-fired electric generating units, such as Martin Plant, and possibly at its steam electric gas-fired Putnam Power Plant. If necessary in the future, FPL will pursue additional controls at those units which prove to be cost effective alternatives to NOx allowance purchases.

For compliance with the CAIR SO2 requirements, space constraints, equipment costs, (including reagent storage, handling, wastes disposal and dewatering systems) make FGD systems cost prohibitive at any of FPL's EGUs. Costs per ton analyses determined that the use of FPL's current and projected bank of SO2 allowances, allocated through Title IV of the Clean Air Act, will be the most cost effective compliance method for meeting CAIR SO2 limits. FPL estimates that it has sufficient SO2 allowances to maintain CAIR compliance through 2020.

Q. What is your analysis of the viability of an open trading market for NOx allowances?

A. A CAIR NOx allowance trading market has not yet developed, since allocations under CAIR have not occurred in states affected by the rule. FPL's research indicates that allowance trading banks are not typically trading NOx allowances beyond 2008. It is not possible at this time to ascertain whether that NOx market will be sufficient to provide enough allowances to maintain compliance. In the interim FPL believes it is prudent to evaluate compliance scenarios that can assure 2009 compliance with or without a robust NOx allowance market.

Q. Please describe FPL's compliance plan if a robust NOx allowance market fails to develop in CAIR affected states.

A. CAIR offers no amnesty for failure to meet emissions limits or provide sufficient allowances to compensate for emissions. Current estimates of NOx emissions in Florida, as compared to NOx allocations, indicate that the state will have a deficit of NOx allowances available to offset emissions. To compensate for this NOx allowance deficit Florida EGUs will be dependent on the purchase of additional allowances out of state, or will be required to add additional emissions control technology than is currently projected by DEP.

The development of the 2009 NOx allowance market in the next two years will determine the necessary response for more control technology or the use of NOx allowances. Thus, in the near future

FPL may need to consider more aggressive pollution control technologies, such as Dry Low NOx Burners at its Putnam Power Plant, Reburn and Low NOx Burner technology at additional FPL generating units, or the use of selective catalytic reduction, for additional NOx emissions reduction.

In contrast, if a robust NOx allowance market develops early, FPL will re-evaluate the extent of its reliance on allowances to achieve CAIR compliance. Reasonably priced and timely available NOx allowances may warrant the delay or reduction in the scope of NOx emissions control equipment projects.

Q. When will FPL begin incurring costs under the CAIR Compliance Project for installation of NOx controls on its oil and gas fired steam units?

A. FPL is proposing to recover the design, engineering and installation cost of NOx controls to be added to the Cape Canaveral, Port Everglades and Turkey Point Plants as described. We project that the initial design, engineering work and procurement for these projects will begin in September 2006. Construction activities will begin in 2007 and continue through 2009. FPL's preliminary Capital estimates are $5.6 million in July through December 2006 and $70.2 million in 2007. FPL currently estimates $132,000,000 total cost to design, engineer and install the Low NOx Burner and Reburn projects proposed.

Q. Please briefly explain why FPL must begin engineering, design and procurement for CAIR-related emissions controls in 2006.

A. For the strategies recommended for CAIR compliance, oil reburn systems typically require at least 10 months for project implementation (from notice-to-proceed to commissioning) and a minimum of a 45-day unit outage for equipment tie-in. Combustion controls systems typically require eight months for project implementation and six weeks outage for equipment tie-in and tuning.

FPL's additions of new pollution control equipment must be tied to planned EGU outage schedules designed to achieve equipment maintenance and upgrades without interrupting system reliability. Based on these time constraints FPL has determined that equipment design, engineering and procurement must begin in September 2006 to achieve the most cost effective compliance approach in 2009.

Q. What is FPL doing to limit its "up-front" CAIR compliance expenditures and commitments, in view of the pending challenges to CAIR?

A. If FPL is successful in challenging EPA's inclusion of Southern Florida in the CAIR region, a majority of FPL oil-fired EGUs would be exempted from all or a portion of CAIR. In view of this possibility, FPL is pursuing the most flexible compliance approach that is practical. To the extent that a robust and reliable NOx trading market can be found, FPL will evaluate reliance on that market to limit early-year exposure to capital dollar expenditures on pollution control equipment. However, as I will discussed previously, there is currently not an established CAIR NOx emissions trading market and no assurances as to how quickly and well one will develop. Therefore, in order to ensure CAIR compliance, access to adequate equipment, materials and manpower and to accommodate reliability driven outage schedules, FPL must move forward through 2007 with the design and scheduling of pollution control equipment and installation plans at its oil fired EGUs. FPL will attempt to reduce contract penalty exposure by building "off-ramps" into contractual agreements that would correspond to anticipated goals in the pending CAIR litigation. FPL anticipates knowing the final status of its litigation by late 2007.

Q. How will FPL ensure that the costs incurred are prudent and reasonable?

A. As our standard practice with all equipment procurements, FPL will competitively bid the pollution control and monitoring equipment in order to ensure the lowest overall cost to our customers. Emission allowances are purchased through auctions or on the open market. FPL will have dedicated staff to evaluate emissions allowance markets and to purchase allowances needed for compliance at an optimum price.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 060007-EI

September 1, 2006

Q. Please state your name and address.

A. My name is Randall R. LaBauve and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Vice President of Environmental Services.

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for the Commission's review and approval the inclusion of Turkey Point Unit 5 as part of FPL's previously approved Selective Catalytic Reduction (SCR) Consumables Project. Additionally, I am including updated cost estimates from those provided in my testimony filed on August 4, 2006 for the Clean Air Mercury Rule (CAMR) and the Clean Air Interstate

Rule (CAIR), and providing an update on FPL's plans to challenge the Florida Department of Environmental Protection's (DEP) rules implementing CAIR.

Q. Have you prepared, or caused to be prepared under your direction, supervision, or control, an exhibit in this proceeding?

A. Yes. It consists of Document RRL-5 - Department of Environmental Protection PSD Permit Conditions – Turkey Point Unit 5 – Section III. Emissions Unit Specific Conditions

Q. Please briefly describe the SCR Consumables Project.

A. The SCR Consumables Project recovers O&M costs associated with consumable goods necessary to operate the SCR systems at Manatee Unit 3 and Martin Unit 8. The SCR systems were required per Expansion Project Final Orders of Certification under the Florida Power Plant Siting Act and the Prevention of Significant Deterioration (PSD) Air Construction Permits at these units. Consumable goods being recovered include anhydrous ammonia, calibration gases, and equipment wear parts requiring periodic replacement such as controllers, ammonia detectors, pressure relief valves, dilution air blower components, NOx control analyzers and components.

Q. Did the Commission approve the SCR Consumables Project in 2004?

A. Yes. The SCR Consumables Project was approved in Order No. PSC-04-1187-FOF-EI, issued on December 1, 2004 in Docket 040007-EI.

Q. Please describe the law or regulation requiring the SCR Consumables Project at Turkey Point Unit 5.

A. The PSD Permit issued on February 8, 2005 for Turkey Point Unit 5 requires the installation and operation of an SCR system for NOx Control. This requirement is consistent with the requirements at Martin Unit 8 and Manatee Unit 3, which were the first units included in the SCR Consumables Project.

Q. Are there any differences in the SCR Consumables Project activities to be performed at Turkey Point Unit 5?

A. There is only one minor difference. Currently, Martin Unit 8 and Manatee Unit 3 use anhydrous ammonia for NOx control. Turkey Point Unit 5 will use aqueous ammonia, which reduces the safety risks associated with ammonia use.

Q. When will FPL begin incurring costs associated with the SCR Consumables Project at Turkey Point Unit 5?

A. FPL expects to begin incurring costs once Turkey Point Unit 5 begins commercial operations. The estimated commercial operation date of Turkey Point Unit 5 is April 23, 2007.

Q. What is FPL's estimated cost for the SCR Consumables Project work at Turkey Point Unit 5?

A. The projected annual O&M cost for this project at Turkey Point Unit 5 is $1.0 million. For 2007, FPL estimates O&M costs of $750,000.

Q. Please explain the updates to the CAIR Compliance Project and CAMR Compliance Project cost estimates.

A. In my testimony filed on August 4, 2006, I provided preliminary cost estimates for the CAMR Compliance and CAIR Compliance projects. Capital cost estimates for the CAMR Compliance Project were projected to be $696,000 for 2006 and $7.9 million for 2007. Project capital costs were estimated to be $47.2 million, for FPL's share of the total cost of compliance at Scherer Unit 4, for the installation of Mercury (Hg) controls.

FPL's updated capital cost estimate for the CAMR Compliance Project for 2007 is $25.7 million, and total project capital cost estimates are now projected to be $97.6 million, for FPL's share of the cost of compliance at Scherer Unit 4 and St. John's River Power Park (SJRPP) Plants, to be incurred through 2010. The updated cost estimates are based upon current estimates received from the operating agents during the 2007 Business Plan cycles. These estimates were received after the August 4th filing.

Capital cost estimates for the CAIR Compliance Project were projected to be $5.6 million for 2006 and $70.2 million for 2007. Project capital costs were estimated to be $132.0 million for the design, engineering, and installation of Low NOx Burners and Reburn equipment at the proposed Cape Canaveral, Port Everglades and Turkey Point Plants.

FPL's updated Capital cost estimate for 2007 is $66.2 million which is not significantly different from the estimate provided in my August 4th testimony. Total project capital cost estimates for the CAIR Compliance Project are now projected to be $535.7 million, to be incurred through 2014. This $535.7 million is based on the following estimates:

Cape Canaveral Units 1 &2	$44.0 Million
Port Everglades Units 3 & 4	$44.0 Million
Turkey Point Unit 1& 2	$44.0 Million
Putnam 1 & 2	$7.5 Million
Scherer Unit 4	$354.6 Million
SJRPP	$41.6 Million

FPL has determined that it will also be necessary to install emissions control technology at its Putnam Plant Units 1 and 2. Currently, FPL is evaluating the installation of water injection technology to control NOx at these units. As noted above, the preliminary capital cost estimate for Putnam Units 1 and 2 is $7.5 million.

Additionally, FPL is projecting annual CAIR Compliance O&M expenses of $25.1 million, for 2008. These expenses are for emission allowances, ammonia injection for the SCR at SJRPP, incremental operating labor and SCR maintenance, and maintenance for reburn equipment. Purchases of emission allowances are estimated to be $22.5 million for 2008 and $11.3 million for 2009 and beyond. Total projected annual O&M costs for the CAIR Compliance project beyond 2009 are $14.0 million.

Q. Do you have any additional updates to the CAIR Compliance Project?

A. Yes. As an option for NOx reduction, FPL is evaluating the improvements needed to be able to cycle the four 800 MW units (Martin 1 & 2 and Manatee 1 &2) reliably. By cycling higher emitting generation off-line more frequently and replacing the generation with low emitting, more efficient gas fired units, the total NOx emissions are reduced. Also, accelerating the in-service date for West County Unit 1 from June to May 2009 will have a favorable impact on seasonal and annual NOx emissions. FPL's O&M estimate for the Martin Units 1 and 2, and Manatee Units 1 and 2 cycling improvement studies is $200,000, to be incurred in 2007. These study costs are not currently reflected in FPL's 2007 projected ECRC costs. FPL plans to reflect these costs in the 2007 estimated/actual true-up filing.

Q. In your 2006 estimated/actual true-up testimony filed on August 4th, you stated that FPL was seriously considering challenging the FDEP's rules implementing CAIR in Florida because the FDEP had used adjustment factors to allocate proportionately more NOx allowances to coal plants at the expense of oil and gas plants. Has FPL now decided whether to pursue that challenge?

A. Yes. FPL filed a rule challenge petition with the Division of Administrative Hearings (DOAH) on August 10, the deadline prescribed by the rule challenge statute.

Q. Please briefly describe the nature of the DOAH rule challenge proceedings.

A. The DOAH proceedings are essentially trial-type administrative hearings, in which the petitioner presents evidence showing that the proposed rule is an invalid exercise of rulemaking authority, the agency presents evidence supporting the proposed rule, and the Administrative Law Judge (ALJ) decides whether to strike or uphold the rule based on the evidence and legal arguments presented by the parties.

Q. When will FPL's rule challenge be decided?

A. The hearing has been set for the week of November 14, 2006. Allowing for briefing after the hearing and time thereafter for the ALJ to review the briefs and make his ruling, FPL expects a decision by early next year.

Q. What does FPL project that the challenge to the FDEP's rule will cost?

A. FPL currently projects that the challenge will cost approximately $250,000 to $350,000. The actual cost will depend in large part upon the complexity of the FDEP's defense of its rules and possible intervention in the proceeding. This is a substantial commitment of resources, but FPL believes it is well justified because there are strong arguments against the validity of the FDEP's rule and, if unchallenged, the rule could result in approximately $13.0 million of additional annual compliance costs for FPL. The costs of challenging the FDEP's rules should be expended primarily in the latter part of 2006 and early in 2007. None of those costs are currently reflected in FPL's 2006 estimated/actual or 2007 projected ECRC costs. FPL plans to reflect the 2006 costs in its 2006 final true-up filing and to reflect the 2007 costs in the 2007 estimated/actual true-up filing.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 060007-EI

September 1, 2006

(Revised October 13, 2006)

Q. Please state your name and address.

A. My name is Randall R. LaBauve and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

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Florida Department of Environmental Protection's (DEP) rules implementing CAIR.

Q. Have you prepared, or caused to be prepared under your direction, supervision, or control, an exhibit in this proceeding?

A. No.

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Q. Does this conclude your testimony?

A. Yes, it does.

(Transcript continues in sequence with Volume 2.)

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, RPR
Official FPSC Hearings Reporter
FPSC Division of Commission Clerk and
Administrative Services
(850) 413-6732