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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 140007-EI

ENVIRONMENTAL COST
RECOVERY CLAUSE.
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VOLUME 1
Pages 1 through 220

PROCEEDINGS: HEARING

COMMISSIONERS: CHAIRMAN ART GRAHAM
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Wednesday, October 22, 2014

TIME: Commenced at 11:05 a.m.
Concluded at 11:18 a.m.

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

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

APPEARANCES:

JOHN T. BUTLER and MARIA J. MONCADA, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power and Light Company.

JAMES D. BEASLEY, J. JEFFRY WAHLEN and ASHLEY M. DANIELS, ESQUIRES, Ausley Law Firm, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

JEFFREY A. STONE, RUSSELL A. BADDERS and STEVEN R. GRIFFIN, ESQUIRES, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591-2950, appearing on behalf of Gulf Power Company.

JOHN T. BURNETT, DIANE M. TRIPLETT, and MATTHEW R. BERNIER, ESQUIRES, 299 First Avenue North, St. Petersburg, Florida 3370, and GARY PERKO, ESQUIRE, Hopping, Green & Sams, P.A., 119 South Monroe Street, Suite 300, Tallahassee, Florida 32301, appearing on behalf of Duke Energy Florida, Inc.

VICKI GORDON KAUFMAN and JON C. MOYLE, JR., ESQUIRES, c/o Moyle Law Firm, P.A., 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

APPEARANCES (Continued):

GEORGE CAVROS, ESQUIRE, Southern Alliance for Clean Energy, 120 E. Oakland Park Boulevard, Suite 105, Fort Lauderdale, Florida 33334, appearing on behalf of Southern Alliance for Clean Energy.

J.R. KELLY, PATRICIA A. CHRISTENSEN, and CHARLES REHWINKEL, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of Florida.

CHARLES MURPHY, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

CURT KISER, GENERAL COUNSEL, and MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisors to the Florida Public Service Commission.

WITNESSES

EXHIBITS

| NUMBER: | ID. | ADMTD. |
|---|---|---|

***** NO EXHIBITS IN VOLUME 1 *****

P R O C E E D I N G S

**CHAIRMAN GRAHAM:** Okay. Now I think it's time to convene the 2014 clause hearing. If I can get the staff to read the order.

**MS. TAN:** By notice issued September 17th, 2014, this time and place is set for a hearing conference in the following dockets: 140001-EI, 140002-EG, 140003-GU, 140004-GU, and 140007-EI. The purpose of the hearing conference is set out in the notice.

**CHAIRMAN GRAHAM:** Okay. Let's take appearances.

**MR. BUTLER:** Good morning, Mr. Chairman. John Butler and Ken Rubin appearing on behalf of FPL in the 02 docket, and John Butler and Maria Moncada appearing on behalf of FPL in the 01 and 07 dockets. Thank you.

**MS. DANIELS:** Good morning, Chairman. Ashley Daniels appearing with James Beasley and Jeffry Wahlen with Ausley McMullen appearing on behalf of Tampa Electric Company in the 01, 02, and 07 dockets. Thank you.

**MR. BERNIER:** Good morning, Commissioners. Matt Bernier with Duke Energy appearing in the 01, 02, and 07 dockets, along with John Burnett and Dianne Triplett. I'd also like to enter an appearance for Gary

Perko in the 07 docket. Thank you.

**MR. BADDERS:** Good morning, Chairman. Russell Badders on behalf of Gulf Power Company. I'd like to enter an appearance for myself, Jeffrey A. Stone, Steven R. Griffin in the 01, 02, and 07 dockets.

**MR. CAVROS:** Good morning, Commissioners. George Cavros on behalf of the Southern Alliance for Clean Energy. I'll be representing the organization in the 02 and the 07 dockets.

**MS. KAUFMAN:** Good morning, Commissioners. Vicki Gordon Kaufman and Jon Moyle of the Moyle Law Firm on behalf of the Florida Industrial Power Users Group in the 01, 02, and 07 dockets.

**MS. KEATING:** Good morning, Commissioners. Beth Keating with the Gunster Law Firm here today for FPU in the 01 and 02 dockets, for FPU and Florida City Gas in the 03 docket, and for FPU, Indiantown, Fort Meade, Florida City Gas, and Chesapeake in the 04 docket.

**MR. WRIGHT:** Good morning, Commissioners. Robert Scheffel Wright and John T. LaVia, III, of the Gardner, Bist, Weiner Law Firm in the 01 fuel cost recovery docket. We're appearing on behalf of the Florida Retail Federation. In the 02 docket we're appearing on behalf of Walmart Stores East and Sam's

East, LP. Thank you.

**MR. REHWINKEL:** Good morning, Commissioners. Charles Rehwinkel, Patty Christensen, and J. R. Kelly with the Office of Public Counsel on behalf of the people of the State of Florida in all dockets.

**MS. TAN:** Martha Barrera for the 01 docket, Lee Eng Tan for the 02 docket, Kyesha Mapp and Keino Young for the 03 docket, Kelley Corbari for the 04 docket, and Charlie Murphy for staff on the 07 docket.

**MS. HELTON:** And I'm Mary Anne Helton. I'm here as your advisor on all the dockets. And I'd also like to enter an appearance for your General Counsel, Curt Kiser.

**CHAIRMAN GRAHAM:** Okay. So those five dockets that we're going to address today, staff, I take it we're taking in the order of docket 02, then 03, then 04, then 01, then 07, in that order?

**MS. TAN:** That is correct. And, Chairman, I'd also like to note that the following parties have been excused from attending the hearing: St. Joe Natural Gas Company in the 03 and the 04 docket, Peoples Gas System in the 03 and the 04 docket, Sebring Gas System in the 04 docket, and PCS Phosphate/White Springs in the 01, 02, and 07 dockets.

**CHAIRMAN GRAHAM:** Okay. Well, if there's nothing else, then I guess we move to the individual dockets.

**MS. TAN:** That is correct.

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**CHAIRMAN GRAHAM:** And we have one remaining docket, which is 140007-EI. I think we can probably take a five-minute break for my court reporter over there. By the back of that clock there, I have five after, so let's restart at 10 after.

(Recess taken.)

Okay. I think we need to reconvene. We need to open the final docket, which is 140007-EI. It's the environmental cost recovery docket.

Staff, preliminary matters.

**MR. MURPHY:** Yes, Commissioner. For the record, PCS Phosphate has been excused from the hearing.

And on October 17th, FPL filed a motion for official recognition the parties may wish to address.

**MR. BUTLER:** Mr. Chairman, excuse me, sorry, you're going to be hearing a bad voice through the morning for which I apologize.

But the motion is simply to officially recognize the *Federal Register* volume in which the rule that's in question here was published. And we provided that copy of the *Federal Register* entry along with our motion for official recognition. No party objected to it. We affirmatively confirmed that the other utilities as well as Office of Public Counsel and SACE did not object to it. We have not heard a response from the Office -- sorry -- from FIPUG on it, but we would move that the Commission take official recognition of that *Federal Register* publication of the proposed rule that's in question for this program.

**CHAIRMAN GRAHAM:** Staff?

**MR. MURPHY:** Staff has no objection.

**CHAIRMAN GRAHAM:** Mary Anne, what do we have to do to take official recognition?

**MR. MURPHY:** Oh, you would need a motion to approve the -- their motion.

**CHAIRMAN GRAHAM:** That's it?

**MS. HELTON:** Mr. Chairman, I think you can just say that you will take official recognition of the document.

**CHAIRMAN GRAHAM:** FIPUG?

**MS. KAUFMAN:** I was just going to say, Mr. Chairman, I have not seen the document, but I will take Mr. Butler at his word. If it is a copy of the rule in the *Federal Register*, we will have no objection.

**CHAIRMAN GRAHAM:** Okay. So we will take official recognition of that document.

What else, staff?

**MR. MURPHY:** Thank you. Yes, there are proposed stipulations of all issues except Issue 9, which will be heard today. Depending on the Commission's eventual decision in Issue 9, there may need to be fallout adjustments to FPL's numbers for Issues 2, 3, 4, and 7. All parties either agree or take no position on the proposed stipulations that are before the Commission today.

Opening statements, if any, are limited to five minutes per party. Staff recommends that opening statements be heard after the Commission addresses the proposed stipulations.

**CHAIRMAN GRAHAM:** Okay.

**MR. BUTLER:** Mr. Chairman? I'm sorry. One just point of clarification. The Prehearing Order reflects the positions on the fallout issues, the dollars and factors issues, that exclude our Waters of the United States, you know, rulemaking project. Obviously it's our position that those costs should be included. So we agree with Mr. Murphy that, you know, the adjustment would be made at the appropriate time. I just wanted to note on the record that it's kind of -- it's listed as a stipulation of an FPL position on that, and really our position going into the hearing is that those costs should be included in the amounts to be recovered. Thank you.

**CHAIRMAN GRAHAM:** Okay.

**MS. KAUFMAN:** I'm sorry. Mr. Chairman, did I understand Mr. Butler to say that those amounts are not included in the factors at the moment?

**MR. BUTLER:** That's right. The figures in Issues 2, 3, 4, and 7 that Mr. Murphy referred to actually exclude the costs for the Waters of the United States project, and, of course, our position is they should be included. And I just wanted to make it clear where the sort of status quo was.

**MS. KAUFMAN:** Thank you. Thank you, Mr. Chairman.

**CHAIRMAN GRAHAM:** Okay. So, staff, we are dealing with the stipulations right now that are, everything except for Issue Number 9; correct?

**MR. MURPHY:** Yes, that's correct. And staff suggested, since the parties are proposing stipulations for all issues except Issue 9, the Commission could make a bench decision in this case. If the Commission decides to make a bench decision, staff recommends the proposed stipulations for Issues 1 through 8 and 10 through 12 should be approved by the Commission.

As indicated in the Prehearing Order, all parties either support or do not oppose the stipulation. Staff recommends that testimony on Issue 9 should be heard once a bench decision is made on the remaining issues.

**CHAIRMAN GRAHAM:** Commissioners? Commissioner Edgar.

**COMMISSIONER EDGAR:** Mr. Chairman, I move approval of the stipulations for Issues 1 through 8 and 10 through 12, with the understanding that if the numbers need to be technically adjusted to reflect the ultimate decision on Issue 9, that Staff would make those adjustments.

**COMMISSIONER BALBIS:** Second.

**CHAIRMAN GRAHAM:** It's been moved and seconded. Any further discussion? Seeing none, all in favor, say aye.

(Vote taken.)

Any opposed? By your action, you have approved the Edgar amendment, the Edgar motion.

Okay. So, staff, we go to --

**MR. MURPHY:** Prefiled testimony.

**CHAIRMAN GRAHAM:** Yes.

**MR. MURPHY:** Yes. Staff recommends the prefiled testimony and exhibits of all witnesses identified in Section VI of the Prehearing Order, except for Witness LaBauve of FPL, be entered into the record at this time as though read.

**CHAIRMAN GRAHAM:** So we will enter all witnesses identified in Section V -- Section VI in the Prehearing Order except for Witness LaBauve will be entered into the record as though read.

**MR. MURPHY:** Thank you.

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**FLORIDA POWER & LIGHT COMPANY**

**TESTIMONY OF TERRY J. KEITH**

**DOCKET NO. 140007-EI**

**APRIL 1, 2014**

**Q. Please state your name and address.**

A. My name is Terry J. Keith 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 Director, Cost Recovery Clauses in the Regulatory & State Governmental Affairs Business Unit.

**Q. Have you previously testified in this or predecessor dockets?**

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 2013 through December 2013.

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

A. Yes, I have. My Exhibit TJK-1 contained in Appendix I consists of nine forms.

- Form 42-1A reflects the final true-up for the period January 2013 through December 2013.
- Form 42-2A provides the final true-up calculation for the period.
- Form 42-3A provides the calculation of the interest provision for the period.
- Form 42-4A provides the calculation of variances between actual and actual/estimated costs for O&M Activities.
- Form 42-5A provides a summary of actual monthly costs for the period for O&M Activities.
- Form 42-6A provides the calculation of variances between actual and actual/estimated costs for Capital Investment Projects.
- Form 42-7A provides a summary of actual monthly costs for the period for Capital Investment Projects.
- Form 42-8A provides the calculation of depreciation expense and return on capital investment for each capital investment project. Pages 40 through 43 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.
- Form 42-9A presents the capital structure, components and cost

rates relied upon to calculate the rate of return applied to capital investments and working capital amounts included for recovery through the ECR for the period.

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

A. Unless otherwise indicated, the data are taken from the books and records of FPL. The books and records are kept in the regular course of FPL's 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 Amount" shows the calculation of the net true-up for the period January 2013 through December 2013, an over-recovery of $2,661,563, which FPL is requesting to be included in the calculation of the ECR factors for the January 2015 through December 2015 period.

The actual end-of-period under-recovery for the period January 2013 through December 2013 of $931,088 (shown on Form 42-1A, Line 3) minus the actual/estimated end-of-period under-recovery for the same period of $3,592,651 (shown on Form 42-1A, Line 6) results in the net true-up over-recovery for the period January 2013 through December 2013 (shown on Form 42-1A, Line 7) of $2,661,563.

**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 end-of-period true-up for the period January 2013 through December 2013. The end-of-period true-up shown on Form 42-2A, lines 5 plus 6 is an under-recovery of $931,088. Additionally, Form 42-3A shows the calculation of the interest provision of $2,903, which is applicable to the end-of-period true-up under-recovery of $928,185.

**Q. Is the true-up calculation consistent with the methodology approved by this Commission for other cost recovery clauses?**

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this 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 2013 through December 2013 compare with FPL’s actual/estimated projections as presented in previous testimony and exhibits?**

A. Form 42-4A shows that total O&M project costs were $1,629,492, or 6.5% lower than projected and Form 42-6A shows that total capital investment project costs were $224,644 or 0.1% lower than projected. Individual project variances are provided on Forms 42-4A and 42-6A. Return on capital investment, depreciation and taxes for each capital project for the period January 2013 through December 2013 are provided on Form 42-8A, pages 12 through 39.

**Q. Please explain the reasons for the significant variances in O&M and capital investment projects.**

A. FPL's variance explanations address variances of greater than approximately 10% from the actual/estimated projections for a project and/or greater than approximately $50,000, referring to these as "significant." There were no significant variances for capital investment projects. The significant variances in FPL's 2013 O&M expenses relate to the following projects:

<u>O&M Variance Explanations</u>

**Project 3a. Continuous Emission Monitoring Systems (CEMS)**

Project expenditures were $133,845 or 21.0% lower than actual/estimated projections. Planned inspections revealed fewer repairs than anticipated for Sanford Plant Unit 4&5 CEMS sample line umbilicals and the Putnam Plant CEMS.

**Project 5a. Maintenance of Stationary Above Ground Fuel Storage Tanks**

Project expenditures were $437,575 or 17.0% lower than actual/estimated projections. The variance is primarily due to delay in conducting the API internal inspection of Manatee Tank 1371/B due to a delay in transferring the fuel inventory from the tank due to less than projected operation of the plant. Additionally, the anticipated scope of planned repairs for Turkey Point Tank #2 was less than originally projected resulting in lower repair expenses.

**Project 8a. Oil Spill Clean-up/Response Equipment**

Project expenditures were $67,351 or 24.3% higher than actual/estimated projections. The variance was due to a greater than anticipated scope of Statute OPA-90, which required maintenance and repair activities to spill response equipment at several FPL power plants and fuel terminals, resulting in higher than projected expenses.

**Project 13. RCRA Corrective Action**

Project expenditures were $37,591 or 75.2% lower than actual/estimated projections. The variance was primarily due to delays by the Florida Department of Environmental Protection (FDEP) to finalize the reviews and approvals of submitted documents. The diesel spill sites were surveyed and a recommendation to discontinue all remediation has been submitted to the FDEP in advance of preparing the required administrative controls (deed restrictions). FPL had anticipated that the diesel spill site closure activities would have been completed in 2013.

**Project 19a. Substation Pollutant Discharge Prevention and Removal – Distribution**

Project expenditures were $631,256 or 32.9% higher than actual/estimated projections. The variance was primarily due to the number of leaking transformers linked to power plants that became available for repair because of unexpected plant outages. Plant outages provide the only opportunity to perform leak repair work on these transformers because they must be de-energized and not in-service. These added opportunities to inspect the transformers led to a higher than projected number of leaking transformers being identified for repair.

**Project 19b. Substation Pollutant Discharge Prevention and Removal – Transmission**

Project expenditures were $304,651 or 34.9% higher than actual/estimated projections. The variance was due to the same reason described above for Project 19a.

**Project 22. Pipeline Integrity Management**

Project expenditures were $227,119 or 81.5% lower than actual/estimated projections. The variance was primarily due to a delay in construction work planned for 2013 as a result of longer than expected Army Corp of Engineers (ACOE) permitting activities associated with the Manatee 16 inch pipeline. In addition, planned maintenance expenses for the 30 inch pipeline at Martin Terminal were lower than originally estimated as a result of lower than projected contractor costs for the required scope of work.

**Project 23. Spill Prevention, Control & Countermeasures – SPCC**

Project expenditures were $65,074 or 6.5% lower than actual/estimated projections. The variance was primarily due to the following reasons:

- Revisions to the SPCC plan were delayed at Martin Plant, Martin Terminal, Manatee Terminal and Sanford Units 4 and 5 in order to complete construction activities at these plants.
- Delay of the SPCC plan at Turkey Point Plant due to complications in gathering supporting documentation required for the SPCC because of security access requirements at the nuclear units.
- Delay in the substation oil diversionary structure (i.e., perimeter curbing) repair work due to an unexpected significant increase in material cost from the supplier. Therefore, other material suppliers are being evaluated.

The variance was partially offset by higher than expected costs resulting from the restoration of the SPCC database and the purchase of a portable secondary containment berm for a tanker truck.

**Project 24. Manatee Reburn**

Project expenditures were $140,094 or 17.0% lower than actual/estimated projections. Planned repairs to the Manatee Plant Reburn System were less than projected resulting in lower than anticipated maintenance costs. The reduction in planned repairs was due to lower than anticipated use of fuel oil in 2013 and hence less wear on the reburn system.

**Project 28. CWA 316(b) Phase II Rule**

Project expenditures were $29,941 or 25.9% lower than actual/estimated projections. The variance was primarily due to the timing of vendor billing. In addition, salaries and expenses were lower than projected due to the delay in the issuance of the final 316 (b) Rule.

**Project 29. Selective Catalytic Reduction Consumables (SCR)**

Project expenditures were $74,195 or 13.5% higher than actual/estimated projections. The variance was primarily due to the replacement of the Manatee Plant ammonia monitor, ammonia air dilution blower, ammonia sensor, and ammonia rescue equipment as identified in the planned inspection. In addition, inspections of the SCR and Ammonia Injection Grid on Martin Unit 8B were performed during an unplanned outage to repair the Unit 8B Heat Recovery Steam Generator. The remainder of the variance is related to an 18% price increase for ammonia in 2013.

**Project 31. CAIR Compliance**

Project expenditures were $123,741 or 2.6% lower than actual/estimated projections. The decrease was primarily due to lower than expected FGD limestone costs and lower than projected maintenance to the limestone handling and preparation equipment. The remainder of the variance was due to lower than projected costs for SCR ammonia.

**Project 33. MATS Project**

Project expenditures were $478,685 or 33.5% lower than actual/estimated projections. The decrease was primarily due to decreased consumption of Powdered Activated Carbon (PAC) resulting in lower than projected PAC costs. Modifications to the PAC injection system were completed on Scherer Unit 4, which lowered the amount of PAC required for mercury removal in 2013.

**Project 35. Martin Plant Drinking Water System Compliance**

Project expenditures were $9,801 or 40.0% higher than actual/estimated projections. The increase was primarily due to increased vendor costs to maintain and clean the Nano membranes. In addition, FPL made a bulk purchase of the system's 5-micron filter cartridges during 2013, which was not expected to occur until 2014.

**Project 37. DeSoto Next Generation Solar Energy Center**

Project expenditures were $64,190 or 7.0% lower than actual/estimated projections. The decrease was primarily due to lower than projected employee costs due to a temporary vacant staff position. Additionally, the installations of inverter container louver fan hoods were deferred to 2014 due to a vendor delay to allow for design improvement and additional fabrication time for the new hoods.

**Project 38. Space Coast Next Generation Solar Energy Center**

Project expenditures were $32,907 or 14.6% lower than actual/estimated projections. The decrease is primarily due to lower than projected employee costs due to a temporary vacant staff position.

**Project 39. Martin Next Generation Solar Energy Center**

Project expenditures were $439,559 or 11.7% lower than actual/estimated projections. The decrease was primarily a result of lower than expected contractor services required for valve replacement and preheater repairs. In addition, replacement of actuator valves originally classified as O&M were later identified as a property retirement unit. As a result, costs were reclassified from O&M to Capital.

**Project 42. Turkey Point Cooling Canal Monitoring Plan**

Project expenditures were $329,535 or 12.8% lower than actual/estimated projections. The variance was primarily due to a reduction in sampling that was required by the FDEP, South Florida Water Management District and Miami-Dade County. FPL submitted its Comprehensive Pre-Uprate Monitoring Plan Report in October 2012 to these agencies. As a result of the data presented in that report, the agencies approved a reduction in monitoring requirements.

**Project 46. St. Lucie Cooling Water Discharge Monitoring**

Project expenditures were $48,942 or 13.1% lower than actual/estimated projections. The decrease was primarily due to delays in the completion of sampling events associated with the Biological Plan of Study (BPOS). The sampling events were completed in January 2014.

**Project 50. Steam Electric Effluent Guidelines Revised Rules**

Project expenditures were $10,000 or 71.1% lower than actual/estimated projections. The decrease was primarily due to a favorable draft rule so that anticipated additional consultant assistance and/or additional waste stream sampling were not required.

**Project 51. Gopher Tortoise Relocation Project**

Project expenditures were $25,250 or 67.3% lower than actual/estimated projections. The decrease was due to fewer required gopher tortoise relocations in 2013 than anticipated.

**Project 52. Numeric Nutrient Criteria Water Quality Standards in Florida**

Project expenditures were $160,600 or 100% lower than actual/estimated projections. The Numeric Nutrient Criteria's final rule was delayed, which resulted in expenditures for sampling, engineering, etc., not occurring in 2013 as had been anticipated.

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

A. Yes, it does.

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**FLORIDA POWER & LIGHT COMPANY**

**TESTIMONY OF TERRY J. KEITH**

**DOCKET NO. 140007-EI**

**JULY 25, 2014**

**Q. Please state your name and address.**

A. My name is Terry J. Keith, 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 or the Company) as Director, Cost Recovery Clauses 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?**

A. The purpose of my testimony is to present for Commission review and approval the Actual/Estimated True-up associated with FPL's environmental compliance activities for the period January 2014 through December 2014.

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

A. Yes, I have. My exhibit TJK-2 consists of nine forms, PSC Forms 42-1E through 42-9E, included in Appendix I.

- Form 42-1E provides a summary of the Actual/Estimated True-up amount for the period January 2014 through December 2014.

- Forms 42-2E and 42-3E reflect the calculation of the Actual/Estimated True-up amount for the period.
- Forms 42-4E and 42-6E reflect the Actual/Estimated 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 12 through 38) reflects return on capital investments and depreciation by project. Pages 39 through 42 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.
- Form 42-9E provides the capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return applied to capital investments and working capital amounts included for recovery for the period January 2014 through December 2014.

**Q. Please explain the calculation of the Environmental Cost Recovery Clause (ECRC) Actual/Estimated True-up amount you are requesting this Commission to approve.**

A. The Actual/Estimated True-up amount for the period January 2014 through December 2014 is an over-recovery, including interest, of $1,109,221

(Appendix I, Page 2, line 5 plus line 6). This Actual/Estimated True-up amount consists of actual data for January 2014 through June 2014 and revised estimates for July 2014 through December 2014, compared to original projections for the same periods.

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

A. All costs listed in Forms 42-1E through 42-8E are associated with environmental compliance projects that have been previously approved by the Commission, with the exception of the Waters of the United States (WOUS) Rulemaking Project. This project is presented for Commission review and approval in the direct testimony of FPL witness Randall R. LaBauve, included in this filing.

**Q. How do the Actual/Estimated project expenditures for January 2014 through December 2014 compare with original projections?**

A. Form 42-4E (Appendix I, Page 4) shows that total O&M project costs were $491,759 or 1.8% higher than projected, while Form 42-6E (Appendix I, Page 8) shows that total capital investment project costs were $1,875,665 or 1.0% lower than projected. Individual project variances are provided on Forms 42-4E and 42-6E. Return on Capital Investment and Depreciation for each project for the Actual/Estimated period are provided on Form 42-8E (Appendix I, Pages 12 through 38).

Explanations for components of the project variances are provided below.

## O&M Project Variances

**Project 1. Air Operating Permit Fees**

Project expenditures are estimated to be $280,320 or 68.8% lower than previously projected. The variance is primarily due to lower than projected fossil plant emissions and the Florida Department of Environmental Protection's (DEP)'s reduction of the rate per ton fee.

**Project 3a. Continuous Emission Monitoring Systems (CEMS)**

Project expenditures are estimated to be $157,369 or 18.4% higher than previously projected. The variance is primarily due to the replacement of the Ft. Myers CEMS umbilicals on the combined cycle and bypass stacks. This was partially offset by lower than expected costs for oil sample analyses at the Martin and Manatee 800 MW units that resulted from lower than projected oil use.

**Project 5a. Maintenance of Stationary Above Ground Fuel Storage Tanks**

Project expenditures are estimated to be $908,160 or 43.3% higher than previously projected. The variance is primarily due to a delay in 2013 to conduct the API internal inspection of Manatee Tank 1371/B resulting from a delay in transferring the fuel inventory from the tank due to less than projected plant operation. This project was originally projected for 2013 but was instead completed in the second quarter of 2014.

**Project 8a. Oil Spill Clean-up/Response Equipment**

Project expenditures are estimated to be $38,724 or 14.8% lower than previously projected. The variance is primarily due to the cancellation of the NRC offshore response contract for barge delivery of oil to the Turkey Point Fossil plant as a result of lower than projected oil usage at the site.

**Project 17a. Disposal of Noncontainerized Liquid Waste**

Project expenditures are estimated to be $196,361 or 99.7% lower than previously projected. Lower than projected oil use at the Manatee, Martin and Turkey Point plants resulted in a reduction of ash production, in turn reducing the need to transport ash from the basins.

**Project 19b. Substation Pollutant Discharge Prevention & Removal - Transmission**

Project expenditures are estimated to be $1,545,730 or 172.7% higher than previously projected. The increase is primarily due to the ability to schedule larger than anticipated regasketing of 37 transformers during the 2014 fall/winter season.

**Project 24. Manatee Reburn**

Project expenditures are estimated to be $172,605 or 34.5% lower than previously projected. The variance is primarily due to lower than projected maintenance costs resulting from fewer than anticipated repairs to the reburn system due to lower than projected use of fuel oil at the plant.

**Project 27. Lowest Quality Water Source**

Project expenditures are estimated to be $18,158 or 11.2% higher than previously projected. The variance is primarily due to the unexpected continued operation of the old demineralized water system at the Sanford plant while installing the new state of the art system.

**Project 28. CWA 316(b) Phase II Rule**

Project expenditures are estimated to be $349,566 or 43.1% lower than previously projected. The variance is primarily due to the delay in the issuance of the Final 316 (b) Rule. A compliance schedule for each affected facility will be discussed with the DEP following issuance of the rule. Significant expenditures are now expected to commence for some facilities in 2015.

**Project 33. MATS Project**

Project expenditures are estimated to be $983,086 or 40.5% lower than previously projected. The variance is primarily due to deferral and renegotiation of the Powder Activated Carbon (PAC) contract for the Scherer baghouse. Actual PAC consumption is lower than originally projected due to improved tuning on the precipitator which resulted in improved mercury control at reduced PAC injection rates.

**Project 37. DeSoto Next Generation Solar Energy Center**

Plant expenditures are estimated to be $86,307 or 10.1% higher than previously projected. The variance is primarily due to higher than expected inverter drive cooling fan failures resulting in an increase in maintenance and repair of support equipment.

**Project 38. Space Coast Next Generation Solar Energy Center**

Plant expenditures are estimated to be $45,851 or 16.8% lower than previously projected. The variance is primarily due to higher than expected equipment reliability resulting in a decrease in anticipated maintenance and repair of support equipment.

**Project 39. Martin Next Generation Solar Energy Center**

Plant expenditures are estimated to be $370,740 or 10.5% higher than previously projected. The variance is primarily due to maintenance and repair of heat transfer fluid (HTF) pump seals. Additionally, maintenance and repairs of system valve components were performed in 2014 rather than later as planned.

**Project 40. Greenhouse Gas Reduction Program**

Project expenditures are estimated to be $20,012 or 226.4% higher than originally projected. The variance is primarily due to increased advocacy activities in response to EPA's proposed Clean Power Plan rule published on June 18, 2014. EPA's proposed GHG rule for existing sources could have significant cost impacts to our customers from our electric generation and FPL believes it is prudent to present appropriate data and analyses to EPA and DPA during development of their final rules.

**Project 41.** **Manatee Temporary Heating System (MTHS) Project**

Project expenditures are estimated to be $117,911 or 21.0% lower than previously projected. The variance is primarily due to the inadvertent inclusion in the 2014 original estimate of costs associated with the installation of the manatee habitat curtain wall at the Port Everglades plant, which was installed in 2013.

**Project 42.** **Turkey Point Cooling Canal Monitoring Plan (TPCCMP)**

Project expenditures are estimated to be $410,290 or 20.4% lower than previously projected. The regulating agencies (Water Management District, DEP and Miami Dade County) have approved a reduction in the amount of monitoring required.

**Project 48.** **Industrial Boiler MACT**

Project expenditures are estimated to be $10,000, versus an original estimate of $0. The variance is primarily due to tune-ups at the Martin Fuel Oil Terminal and a one-time energy audit, which will be performed in 2014 rather than later as originally planned.

**Project 49.** **Thermal Discharge Standards**

Project expenditures are estimated to be $46,122 or 32.3% higher than previously projected. Sampling required by the DEP to remain compliant with the thermal standards at the Cape Canaveral plant that was originally scheduled to occur in 2013, will now be accomplished in 2014. Additionally, monitoring was performed at the Riviera plant to confirm that thermal discharges from the newly modernized plant were not negatively impacting sea grasses in the Lake Worth Lagoon. FPL had the opportunity to make changes to Riviera's Thermal Discharge Standard compliance plan to allow completion in 2014, rather than 2015.

**Project 50. Steam Effluent Guidelines**

Project expenditures are estimated to be $36,000 or 70.6% lower than previously projected. The variance is primarily due to the outcome of the newly revised proposed rule. Requirements are less stringent than anticipated for oil and gas-fired plants, so additional analyses and consulting assistance were not required.

**Project 52. Numeric Nutrient Criteria (NNC) Water Quality Standards in Florida**

Project expenditures are estimated to be $274,913 or 99.5% lower than previously projected. The decrease is primarily due to a delay in the issuance of the final rule.

## Capital Project Variances

**Project 2. Low NOX Burner Technology**

Project depreciation and return on investment are estimated to be $54,279 or 32.3% lower than previously projected. The variance is primarily attributed to the retirement of assets at Turkey Point Unit 2 in December 2013. This in turn reduced depreciation expense for the 2014 calendar year.

**Project 8b. Oil Spill Cleanup/Response Equipment**

Project depreciation and return on investment are estimated to be $22,666 or 13.6% lower than previously projected. The variance is mostly due to timing of the Fixed Oil Spill Boom installation. The project was delayed due to the scheduling of outages and is planned to be completed in the winter of 2014. This in turn reduced depreciation expense for the 2014 calendar year.

**Project 21. St. Lucie Turtle Nets**

Project depreciation and return on investment are estimated to be $111,023 or 66.0% higher than previously projected. The variance is primarily attributed to a change of the in-service date for the permanent turtle net barrier structure from December 2014 to October 2014.

**Project 31. Clean Air Energy Rule (CAIR)**

Project depreciation and return on investment are estimated to be $761,018 or 1.3% lower than previously projected. The variance is due to a coding error involving three CAIR related work orders in PowerPlant. These were coded as base recoverable instead of ECRC recoverable investment and will be corrected in the month of July 2014.

**Project 36. Low-Level Radioactive Waste Storage**

Project depreciation and return on investment are estimated to be $633,659 or 35.6% lower than previously projected. The variance is primarily due to the in-service timing of approximately $9.5 million associated with construction of the low-level radioactive storage facility at Turkey Point, thus lowering the return calculation and depreciation expense. The in-service date for the $9.5 million was moved from March 2014 to September 2014.

**Project 39. Martin Next Generation Solar Energy Center**

Project depreciation and return on investment are estimated to be $359,076 or 0.8% higher than previously projected. The variance is primarily due to increased costs as a result of delays in the solar preheater and recirculation projects as well as associated required scope changes.

**Project 45. 800 MW Unit ESP**

Project depreciation and return on investment are estimated to be $777,129 or 3.6% lower than previously projected. This variance is directly attributed to Siemens design change orders and the shift of milestone achievements to 2014. The shift affected beginning plant balance thus lowering the return calculation and the depreciation expense.

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

A. Yes, it does.

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**FLORIDA POWER & LIGHT COMPANY**

**TESTIMONY OF TERRY J. KEITH**

**DOCKET NO. 140007-EI**

**AUGUST 22, 2014**

**Q. Please state your name and address.**

A. My name is Terry J. Keith 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 or the Company) as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

**Q. Have you previously testified in this docket or any other predecessor dockets?**

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 FPL's Environmental Cost Recovery Clause (ECRC) projections for the January 2015 through December 2015 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. Exhibit TJK-3 provides the calculation of FPL's proposed ECRC factors for the period January 2015 through December 2015. TJK-3 includes PSC Forms 42-1P through 42-8P, which are provided in Appendix I.

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

A. Yes, with the exception of estimated costs associated with the Waters of the United States Rulemaking (WOUS) Project. FPL has petitioned the Commission in this docket on July 25, 2014 to approve the WOUS Project for ECRC recovery.

**Q. Please describe Form 42-1P.**

A. Form 42-1P (Appendix I, Page 1) provides a summary of projected environmental costs being requested for recovery for the period January 2015 through December 2015. Total environmental requirements, adjusted for revenue taxes, are $205,333,619 (Appendix I, Page 1, Line 5) and include $208,956,669 of environmental project jurisdictional revenue requirements for the January 2015 through December 2015 period (Appendix I, Page 1, Line 1c) decreased by the actual/estimated true-up over-recovery of $1,109,221 for the January 2014 through December 2014 period (Appendix I, Page 1, Line 2), and decreased by the final true-up over-recovery of $2,661,563 for the January 2013 through December 2013 period (Appendix I, Page 1, Line 3).

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

A. Form 42-2P (Appendix I, Pages 2 and 3) 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. FPL is projecting total jurisdictional O&M costs of $25,582,520 for the period January 2015 through December 2015.

Form 42-3P (Appendix I, Pages 4 and 5) presents the depreciation expense and return on capital investment associated with FPL's environmental projects for the projected period. Form 42-3P also provides the calculation of total jurisdictional costs for these projects, classified by energy and demand. FPL is projecting total jurisdictional capital depreciation expense and return on investment of $183,374,149 for the period January 2015 through December 2015.

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 6 through 36) 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 37 through 102) provides the description and progress of approved environmental projects included in the projected period.

**Q. Please describe Form 42-6P.**

A. Form 42-6P (Appendix I, Page 103) 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 class contributes to total kWh sales, as adjusted for losses.

**Q. Please describe Form 42-7P.**

A. Form 42-7P (Appendix I, Page 104) presents the calculation of the proposed 2015 ECRC factors by rate class.

**Q. Please describe Form 42-8P.**

A. Form 42-8P (Appendix I, Page 105) presents the capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return applied to capital investments and working capital amounts included for recovery through the ECRC for the period January 2015 through December 2015. Per Order No. PSC-12-0425-PAA-EU issued on August 16, 2012, FPL is using the capital structure and cost rates from the May 2014 Earnings Surveillance Report.

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

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

THOMAS G. FOSTER

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

April 1, 2014

**Q. Please state your name and business address.**

A. My name is Thomas G. Foster. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

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

A. I am employed by Duke Energy Business Services, LLC, as Director, Rates and Regulatory Planning.

**Q. What are your responsibilities in that position?**

A. I am responsible for regulatory planning and cost recovery for Duke Energy Florida (DEF). These responsibilities include: regulatory financial reports and analysis of state, federal and local regulations and their impact on DEF. In this capacity, I am also responsible for DEF's True-up, Estimated/Actual, and Projection filings in the Environmental Cost Recovery Clause (ECRC).

**Q. Please describe your educational background and professional experience.**

A. I joined DEF on October 31, 2005 as a Senior Financial Analyst in the Regulatory group. In that capacity I supported the preparation of testimony and exhibits associated with various dockets. In late 2008, I was promoted to Supervisor Regulatory Planning. In 2012, following the merger with Duke Energy, I was promoted to my current position. Prior to working at DEF, I was the Supervisor in the Fixed Asset group at Eckerd Drug. In this role I was primarily responsible for ensuring proper accounting for all fixed assets in addition to various other accounting responsibilities. I have six years of experience related to the operation and maintenance of power plants obtained while serving in the United States Navy as a Nuclear operator. I received a Bachelor of Science degree in Nuclear Engineering Technology from Thomas Edison State College. I received a Masters of Business Administration with a focus on finance from the University of South Florida and I am a Certified Public Accountant in the State of Florida.

**Q. Have you previously filed testimony before this Commission in connection with DEF's ECRC?**

A. Yes.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to present for Commission review and approval DEF's actual true-up costs associated with environmental compliance activities for the period January 2013 through December 2013.

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

A. Yes. I am sponsoring Exhibit No.___ TGF-1, that consists of nine forms and Exhibit No.___ TGF-2 that provides details of five capital projects by site.

Exhibit No.___ TGF-1 consists of the following:

- Form 42-1A is the final true-up for the period January 2013 through December 2013.
- Form 42-2A is the final true-up calculation for the period.
- Form 42-3A is the calculation of the interest provision for the period.
- Form 42-4A is the calculation of variances between actual and estimated/actual costs for O&M Activities.
- Form 42-5A is a summary of actual monthly costs for the period for O&M Activities.
- Form 42-6A is the calculation of variances between actual and estimated/actual costs for Capital Investment Projects.
- Form 42-7A is a summary of actual monthly costs for the period for Capital Investment Projects.
- Form 42-8A, pages 1 through 19, is the calculation of return on capital investment, depreciation expense and property tax expense for each project recovered through the ECRC.
- Form 42-9A is DEF's capital structure and cost rates.

Exhibit No.___ TGF-2 consists of detailed support for the following capital projects:

- Pipeline Integrity Management (Capital Program Detail (CPD), pages 2 through 3)
- Above Ground Storage Tank Secondary Containment (CPD, pages 4 through 9)
- Clean Air Interstate Rule (CAIR) Combustion Turbines (CTs)(CPD, pages 10 through 13)
- CAIR-Crystal River Units 4 & 5 (CPD, pages 14 through 23)
- Thermal Discharge Permanent Cooling Tower (CPD, page 24)

These exhibits are true and accurate.

**Q. What is the source of the data that you will present in testimony and exhibits in this proceeding?**

A. The actual data is taken from the books and records of DEF. The books and records are kept in the regular course of DEF's business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by Federal Energy Regulatory Commission and any accounting rules and orders established by this Commission.

**Q. What is the final true-up amount DEF is requesting for the period January 2013 through December 2013?**

A. DEF requests approval of an under-recovery amount of $13,759,174 for the calendar period ending December 31, 2013. This amount is shown on Form 42-1A, Line 1.

**Q. What is the net true-up amount DEF is requesting for the period January 2013 through December 2013 to be applied in the calculation of the environmental cost recovery factors to be refunded/recovered in the next projection period?**

A. DEF requests approval of an over-recovery of $3,807,998 reflected on Line 3 of Form 42-1A, as the adjusted net true-up amount for the period January 2013 through December 2013. This amount is the difference between an actual under-recovery amount of $13,759,174 and an actual/estimated under-recovery of $17,567,172, as approved in Order PSC-13-0606-FOF-EI, for the period January 2013 through December 2013.

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

A. Yes.

**Q. How did actual O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections as presented in previous testimony and exhibits?**

A. Form 42-4A shows a total O&M project variance of $5,468,111 lower than projected. Individual O&M project variances are on Form 42-4A. Explanations associated with variances are contained in the direct testimony of Mark Hellstern, Jeffrey Swartz, Patricia Q. West and Corey Zeigler.

**Q. How did actual capital recoverable expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections as presented in previous testimony and exhibits?**

A. Form 42-6A shows a total capital investment recoverable cost variance of $107,475 higher than projected. Individual project variances are on Form 42-6A. Return on capital investment, depreciation and property taxes for each project for the period are provided on Form 42-8A, pages 1 through 19. Explanations associated with variances are contained in the direct testimony of Mr. Hellstern, Mr. Swartz and Ms. West.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

THOMAS G. FOSTER

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

July 25, 2014

**Q. Please state your name and business address.**

A. My name is Thomas G. Foster. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

**Q. Have you previously filed testimony before this Commission in Docket No. 140007-EI?**

A. Yes, I provided direct testimony on April 1, 2014.

Q: **Has your job description, education background and professional experience changed since that time?**

A. No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to present, for Commission review and approval, Duke Energy Florida's (DEF) estimated/actual true-up costs associated with environmental compliance activities for the period January 2014 through

December 2014. I also explain the variance between 2014 estimated/actual cost projections versus original 2014 cost projections for emission allowances (Project 5).

**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 the following exhibits:

1. Exhibit No. __TGF-3, which consists of PSC Forms 42-1E through 42-9E; and
2. Exhibit No. __TGF-4, which provides details of capital projects by site.

These exhibits provide detail on DEF's estimated/actual true-up capital and O&M environmental costs and revenue requirements for the period January 2014 through December 2014.

**Q. What is the estimated/actual true-up amount for which DEF is requesting recovery for the period of January 2014 through December 2014?**

A. The estimated/actual true-up for 2014 is an over-recovery, including interest, of $11,344,981 as shown on Form 42-1E, line 4. This amount is added to the final true-up over-recovery of $3,807,998 for 2013 as shown on Form 42-2E, Line 7a, resulting in a net over-recovery of $15,152,979 as shown on Form 42-2E, Line 11. The calculations supporting the estimated true-up for 2014 are on Forms 42-1E through 42-8E.

**Q. What capital structure, components and cost rates did DEF rely on to calculate the revenue requirement rate of return for the period January 2014 through December 2014?**

A. The capital structure, components and cost rates relied on to calculate the revenue requirement rate of return for the period January 2014 through December 2014 are shown on Form 42-9E. This form includes the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Form 42-8E. Form 42-9E also cites the source and includes the rationale for using the particular capital structure and cost rates.

**Q. How do estimated/actual O&M expenditures for January 2014 through December 2014 compare with original projections?**

A. Form 42-4E shows that total O&M project costs are estimated to be approximately $1.9 million or 4% higher than originally projected. This form also lists individual O&M project variances. Explanations for these variances are included in the direct testimony of Jeffrey Swartz, Patricia Q. West and Corey Zeigler, except for Emission Allowances which is below.

**Emissions Allowances (Project 5) – O&M**

$SO_2$ and NOx expenses are estimated to be approximately $162k or 5% higher than originally projected primarily due to increased generation at Crystal River Units 1&2.

**Q. How do estimated/actual capital recoverable costs for January 2014 through December 2014 compare with DEF's original projections?**

A. Form 42-6E shows that total recoverable capital costs are estimated to be approximately $480k or 2% lower than originally projected. This form also lists individual project variances. The return on investment, depreciation expense and property taxes for each project for the estimated/actual period are provided on Form 42-8E, pages 1 through 18. Explanations for these variances are included in the direct testimony of Mr. Delowery, Mr. Swartz and Ms. West.

**Q: Please explain the adjustments on Line 4c on Form 42-2E for the Citrus County Property Tax Settlement.**

A: In March 2014, DEF reached a property tax settlement with Citrus County for 2012 and 2013 ending a dispute over the assessed values of pollution control assets at the Crystal River site. An adjustment of approximately $14.3 million was made in March 2014 to reflect the retail portion of the property tax settlement applicable to the Environmental Cost Recovery Clause (ECRC). Another adjustment of approximately $586k was made in May 2014 for outside legal fees paid by DEF for successful settlement of the property tax dispute associated with affected assets in the ECRC.

The $14.3 million was calculated as the difference between the original (pre-settlement) property tax rates and settlement property rates applicable to the ECRC Crystal River projects for years 2012 and 2013. The resulting amount was multiplied by the respective 2012 and 2013 separation factors for the impacted ECRC Crystal River projects to derive the $14.3 million.

The $586k legal success fees represents the ECRC portion of a total of $1 million paid to an outside law firm for favorable resolution of the Citrus County property tax dispute. $635k of the $1 million was allocated to the ECRC based on the percent of the settlement amount applicable to clause assets. This amount was multiplied by the appropriate 2012 and 2013 separation factors to derive the $586k.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

THOMAS G. FOSTER

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

AUGUST 22, 2014

**Q. Please state your name and business address.**

A. My name is Thomas G. Foster. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

**Q. Have you previously filed testimony before this Commission in Docket No. 140007-EI?**

A. Yes. I provided direct testimony on April 1, 2014 and July 25, 2014.

**Q. Has your job description, education background or professional experience changed since that time?**

A. No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to present, for Commission review and approval, Duke Energy Florida's (DEF or the Company) calculation of revenue requirements and Environmental Cost Recovery Clause (ECRC) factors for customer billings for the period January 2015 through December 2015. My testimony also addresses capital and O&M expenses associated with DEF's environmental compliance activities for the year 2015.

**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 the following exhibits:

1. Exhibit No. __(TGF-5), which consists of PSC Forms 42-1P through 42-8P; and
2. Exhibit No. __(TGF-6), which provides details of capital projects.

The individuals listed below are co-sponsors of Forms 42-5P pages 1-4 and 6-21 as indicated in their direct testimony. I am sponsoring Form 42-5P page 5.

- Mr. Zeigler will co-sponsor Forms 42-5P pages 1, 2 and 10.
- Ms. West will co-sponsor Forms 42-5P pages 3, 4, 6, 8, 9, 11, 12, 13, 14, 15, 16, 17, 18, and 19.
- Mr. Swartz and Ms. West will co-sponsor Form 42-5P page 7.
- Mr. Delowery will co-sponsor Form 42-5P page 20.
- Mr. Swartz will co-sponsor Form 42-5P page 21.

**Q. What is the total recoverable revenue requirement for the period January 2015 through December 2015?**

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is approximately $50.4 million as shown on Form 42-1P line 5 of Exhibit No. __(TGF-5).

**Q. What is the total true-up to be applied for the period January 2015 through December 2015?**

A. The total true-up applicable to this period is an over-recovery of approximately $15.2 million. This amount consists of the final true-up over-recovery of approximately $3.8 million for the period January 2013 through December 2013 and an estimated true-up over-recovery of approximately $11.3 million for the current period of January 2014 through December 2014. The detailed calculation supporting the 2014 estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. __ (TGF-3) filed with the Commission on July 25, 2014.

**Q. Are all the costs listed on Forms 42-1P through 42-7P attributable to environmental compliance programs previously approved by the Commission?**

A. Yes. The following ECRC programs were previously approved by the Commission:

The Substation and Distribution System O&M Programs (Project 1 & 2) were previously approved in Order No. PSC-02-1735-FOF-EI.

The Pipeline Integrity Management Program (Project 3) and the Above Ground Tank Secondary Containment Program (Project 4) were previously approved in Order No. PSC-03-1348-FOF-EI.

The recovery of sulfur dioxide ($SO_2$) Emission Allowances (Project 5) was previously approved in Order No. PSC-95-0450-FOF-EI, however, the costs were moved to the ECRC docket from the Fuel docket beginning January 1, 2004 at the request of Staff to be consistent with the other Florida investor owned utilities.

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

DEF's Integrated Clean Air Compliance Plan (Project 7) was approved by the Commission as a prudent and reasonable means of complying with the Clean Air Interstate Rule and related regulatory requirements in Order No. PSC-07-0922-FOF-EI.

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

The Modular Cooling Tower Program (Project 11) was previously approved in Order No. PSC-07-0722-FOF-EI.

The Crystal River Thermal Discharge Compliance Project (Project 11.1) and Greenhouse Gas Inventory and Reporting Project (Project 12) were previously approved in Order No. PSC-08-0775-FOF-EI.

The Total Maximum Daily Loads for Mercury Project (Project 13) was previously approved in Order No. PSC-09-0759-FOF-EI.

The Hazardous Air Pollutants (HAPs) ICR Project (Project 14) was previously approved in Order No. PSC-10-0099-PAA-EI.

The Effluent Limitations Guidelines ICR Project (Project 15) was previously approved in Order No. PSC-10-0683-PAA-EI.

The National Pollutant Discharge Elimination System (NPDES) Project (Project 16) was previously approved in Order No. PSC-11-0553-FOF-EI.

The Mercury & Air Toxic Standards (MATS) Project (Project 17) which replaces Maximum Achievable Control Technology (MACT) was previously approved in Order Nos. PSC-11-0553-FOF-EI, PSC-12-0432-PAA-EI and PSC-14-0173-PAA-EI.

**Q. What capital structure, components and cost rates did DEF rely on to calculate the revenue requirement rate of return for the period January 2015 through December 2015?**

A. DEF used the capital structure, components and cost rates consistent with the language in Order No. PSC-12-0425-PAA-EU. As such, DEF used the rates contained in its May 2014 Earnings Surveillance Report Weighted Average Cost of Capital. These rates are shown on Form 42-8P, Exhibit No. ___(TGF-5). Form 42-8P includes the derivation of debt and equity components used in the Return on Average Net Investment, Form 42-4P lines 7 a and b.

**Q. What is the proposed accounting treatment for emission allowances if the Cross State Air Pollution Rule (CSAPR) is reinstated?**

A. As stated in Ms. West's direct testimony dated July 25, 2014, the EPA has petitioned the D. C. Circuit Court to lift the CSAPR stay and direct that the rule take effect beginning January 1, 2015. Due to the uncertainty surrounding the outcome of the court ruling, DEF has not changed its accounting treatment of emission allowances in 2015.

In Order No. PSC-11-0553-FOF-EI dated December 11, 2011, the Commission authorized DEF to establish a regulatory asset and associated three year amortization schedule to recover the cost of nitrogen oxide (NOx) emission allowances that at the time were thought to be unusable as a result of regulatory developments associated with CSAPR. DEF did not implement this accounting treatment due to the subsequent stay and vacatur of CSAPR by the courts. In the event CSAPR takes effect, DEF plans to follow the accounting treatment previously approved by the Commission to account for these emission allowances.

**Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2015?**

A. Yes. Form 42-2P of Exhibit No. __ (TGF-5) summarizes recoverable jurisdictional O&M cost estimates for these projects of approximately $36.2 million.

**Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2015?**

A. Yes. Form 42-3P of Exhibit No. __ (TGF-5) summarizes recoverable jurisdictional capital cost estimates for these projects of approximately $29.3 million. Form 42-4P pages 1 through 18 shows detailed calculations of these costs.

**Q. Have you prepared schedules providing progress reports for all environmental compliance projects?**

A. Yes. Form 42-5P pages 1 through 21 of Exhibit No. __ (TGF-5) provide a description, progress summary and recoverable cost estimates for each project.

**Q. What are the total projected jurisdictional costs for environmental compliance projects for the year 2015?**

A. Total jurisdictional capital and O&M costs of approximately $65.5 million to be recovered through the ECRC are calculated on Form 42-1P line 1c of Exhibit No. __ (TGF-5).

**Q. Please describe how the proposed ECRC factors are developed.**

A. The ECRC factors are calculated as shown on Forms 42-6P and 42-7P of Exhibit No. __(TGF-5). The demand component of class allocation factors are calculated by determining the percentage each rate class contributes to monthly system peaks adjusted for losses for each rate class which is obtained from DEF's load research study filed with the Commission in July 2012. The energy allocation factors are calculated by determining the percentage each rate class contributes to total kilowatt-hour sales adjusted for losses for each rate class. Form 42-7P presents the calculation of the proposed ECRC billing factors by rate class.

**Q. What are DEF's proposed 2015 ECRC billing factors by the various rate classes and delivery voltages?**

A. The calculation of DEF's proposed ECRC factors for 2015 customer billings is shown on Form 42-7P in Exhibit No. __(TGF-5) as follows:

| RATE CLASS | ECRC FACTORS<br>12CP & 1/13AD |
|---|---|
| Residential | 0.138 cents/kWh |
| General Service Non-Demand | |
| @ Secondary Voltage | 0.133 cents/kWh |
| @ Primary Voltage | 0.132 cents/kWh |
| @ Transmission Voltage | 0.130 cents/kWh |
| General Service 100% Load Factor | 0.125 cents/kWh |
| General Service Demand | |
| @ Secondary Voltage | 0.129 cents/kWh |
| @ Primary Voltage | 0.128 cents/kWh |
| @ Transmission Voltage | 0.126 cents/kWh |
| Curtailable | |
| @ Secondary Voltage | 0.123 cents/kWh |
| @ Primary Voltage | 0.122 cents/kWh |
| @ Transmission Voltage | 0.121 cents/kWh |
| Interruptible | |
| @ Secondary Voltage | 0.122 cents/kWh |
| @ Primary Voltage | 0.121 cents/kWh |
| @ Transmission Voltage | 0.120 cents/kWh |
| Lighting | 0.114 cents/kWh |

**Q. When is DEF requesting that the proposed ECRC billing factors be effective?**

A. DEF is requesting that its proposed ECRC billing factors be effective with the first bill group for January 2015 and continue through the last bill group for December 2015.

**Q. Please summarize your testimony.**

A. My testimony supports the approval of an average ECRC billing factor of 0.133 cents per kWh which includes projected jurisdictional capital and O&M revenue requirements for the period January 2015 through December 2015 of approximately $65.5 million associated with a total of 17 environmental projects, and a true-up over-recovery provision of approximately $15.2 million from prior periods. My testimony also supports that projected environmental expenditures for 2015 are appropriate for recovery through the ECRC.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

MARK HELLSTERN

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

April 1, 2014

**Q. Please state your name and business address.**

A. My name is Mark Hellstern. My business address is 1729 Bailles Bluff Rd. Holiday, Florida, 34691.

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

A. I am employed by Duke Energy Florida (DEF) as the Project Director for the Anclote Gas Conversion Project.

**Q. What are your responsibilities in that position?**

A. My responsibilities entail major project planning and execution, including oversight, construction, commissioning and start up. My primary duties involve managing engineering activities to ensure project scope is accurate and complete, providing input to estimate development, assisting in the development of project execution, and contracting strategies, and providing input to the overall project schedules and oversight of construction execution. These duties are relevant to projects that emerge from system planning and environmental planning activities where specific projects are identified as viable projects that will move forward into funding, contracting, design, construction and startup phases. My area generally accommodates projects in excess of $50 million in value.

**Q. Please describe your educational background and professional experience.**

A. I started with DEF in December 2011 as the Major Project Manager for the Crystal River Unit 3 Containment Repair Project, and was responsible for managing engineering activities, estimate development, scope certainty, project staffing and management, options analysis, and contract negotiations and selection of vendors to repair the containment structure. In late 2012, I assumed a rotational assignment as Manager, Project Governance in support of building project management governance and processes for the newly merged company. I assumed the position as Project Director for the Anclote Gas Conversion Project in late June 2013 due to George Hixon's retirement. Previously, from 2009-2011, I was employed by Tennessee Valley Authority as General Manager, Nuclear Generation Development and Construction for Quality and Construction Oversight. In this capacity, I was responsible for the development and implementation of nuclear construction quality programs, construction oversight and project management processes. I had oversight of the Watts Bar II Completion Project, Bellefonte Completion Project, and Major Nuclear Outages over $100M. In a rotational leadership assignment, I was also the Senior

Manager, Project Support and Infrastructure, for the Bellefonte Nuclear Plant Construction Completion Project. In 2009, I retired as a Captain in the US Navy after 26 years of service. In my last assignment, from 2006-2009, I was the Senior Advisor to the Director, Naval Reactors, for Aircraft Carrier Operations and Fleet Training Initiatives, and was the Senior Naval Officer charged with oversight of the Navy's 11 nuclear aircraft carriers for safe operations, maintenance, construction, and refueling including the training programs for over 1500 nuclear operators. I served on 8 ships through 11 combat deployments and commanded the USS HAYLER (DD 997). I have led or had leadership roles in shipbuilding and commercial projects ranging from $3M to $5B. I served in the Pentagon as the Secretary of Defense Deputy Director for Asian and Pacific Affairs and as the Executive Assistant to the Principle Deputy Secretary of Defense for Policy. I hold a BS in Marine Engineering from the US Naval Academy and an MS in Physics with Distinction from the US Naval Postgraduate School. I am a distinguished graduate of the Air Command and Staff College and was the Senior Military Fellow at MIT in Security Studies.

**Q: Have you previously filed testimony before this Commission in connection with DEF's Environmental Cost Recovery Clause?**

A. Yes.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide an update on the Mercury and Air Toxics Standards (MATS) - Anclote Gas Conversion Project (Project 17.1) and to explain material variances between actual and estimated/actual project expenditures for the period January 2013 through December 2013.

**Q. What is the estimated total project costs for the MATS – Anclote Gas Conversion Project?**

A. DEF's current estimate to complete is approximately $137 million.

**Q. Does the Anclote Gas Conversion Project remain on schedule to meet its targeted in-service date?**

A. Yes, as indicated in my August 30, 2013 direct testimony in Docket No. 130007-EI, gas conversion work was completed in July 2013 for Unit 1 and December 2013 for Unit 2. The FD fan modifications are scheduled for 2014. Unit 1 FD fan modification work is in progress and is expected to be completed in late Spring 2014. Unit 2 FD fan modification work is scheduled for Fall 2014.

**Q: Please explain the variance between actual project expenditures and estimated/actual projections for the Anclote Gas Conversion Project for the period January 2013 to December 2013.**

A. The project expenditure variance for the Anclote Gas Conversion Project is approximately $9M higher than projected. This variance is primarily attributable to expenditures in 2013 for the gas conversion scopes of work for Unit 1 and Unit 2 including: 1) installation of increased electrical and piping quantities to complete gas conversion work on both units, 2) early arrival of the Unit Auxiliary Transformers for the new FD fan modifications in 2013 versus 2014 and 3) accounting accruals of Alstom large equipment deliveries and contractual payments.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

MICHAEL R. DELOWERY

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

July 25, 2014

**Q. Please state your name and business address.**

A. My name is Michael Delowery. My current business address is 400 South Tryon Street, Charlotte, NC 28202.

**Q: By whom are you employed?**

A: I am employed by Duke Energy, Inc. (DEF or the Company) and currently serve as the acting Vice President of Project Management and Construction (PMC). I was appointed the acting Vice President, PMC, when Mr. John Elnitsky, the prior VP PMC, was asked to take on a strategic role with the coal ash taskforce. Prior to being appointed as acting VP PMC, I was the General Manager, Projects, PMC. Duke Energy Florida, Inc. is a fully owned subsidiary of Duke Energy.

**Q: What are your responsibilities in that position?**

A: As the acting VP PMC, I report directly to the Executive Vice President, Duke Energy, and President, Duke Energy Nuclear. In this role, I am the senior manager who has oversight responsibility for new power plant construction and retrofit of existing fossil and hydro-electric power plants for Duke Energy. This includes the Anclote Gas Conversion Project. My responsibilities also include oversight of decommissioning the Crystal River Unit 3 (CR3) plant. Prior to my current role, I was the General Manger of Projects in PMC. Prior to that, I was the Decommissioning Planning Manager at CR3

**Q: Please describe your educational background and professional experience.**

A: I hold a Bachelor of Science in Mechanical Engineering from Drexel University and have over 22 years of experience in the power industry. I initially joined DEF in May 2011 as the General Manager responsible for the potential repair of the CR3 containment building. In February 2014, I was appointed to my current position. Prior to joining Duke Energy, I worked for Florida Power & Light (FP&L) where I held various management positions including Project Director of the St. Lucie Nuclear Power Plant Extended Power Uprate, Maintenance Director, Project Director of the St. Lucie Nuclear Power Plant Steam Generators and Reactor Head Replacement Projects, and Manager of Projects. Prior to joining FP&L, I held a number of positions at Exelon and completed a rotational assignment with the Institute of Nuclear Power Operations as a senior evaluator of equipment reliability for both domestic and international nuclear power stations

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide an update on the Mercury and Air Toxics Standards (MATS) - Anclote Gas Conversion Project (Project 17.1).

**Q: Did you review the Direct Testimony of Mark Hellstern filed in this docket on April 1, 2014?**

A: Yes, and I will be adopting Mr. Hellstern's April 1, 2014 testimony on behalf of the Company. I have personal knowledge of the facts stated in his testimony due to my oversight of the project to date. I have responsibility for and provide oversight of this project, and I have a full understanding of the scope and execution of the project.

**Q. What costs do you expect to incur in 2014 in connection with the MATS – Anclote Gas Conversion Project (Project 17.1)?**

A. DEF expects to incur $34 million of costs in 2014 for the Anclote Gas Conversion project. These costs include contractor mobilization; permit activities; Force Draft (FD) Fan modification engineering services; startup and commissioning; balance of plant engineered equipment procurement for the FD Fan scope of work; procurement of remaining components for the FD Fan modification; construction completion costs for Unit 2 gas conversion; field engineering; contractor construction execution; and close out costs.

**Q. Please explain the variance between the estimated/actual project expenditures and original projections for the MATS – Anclote Gas Conversion Program (Project 17.1) for the period January 2014 to December 2014.**

A. Expenditures are expected to be $633k or 2% higher than originally projected primarily due to timing of the installation of the FD fan modifications. The original projections were based on both Unit 1 and Unit 2 fans being installed in the second quarter 2014. However, Unit 1 FD fan modification work was completed second quarter 2014 and Unit 2 fan modification work is now scheduled for late fourth quarter 2014 which coincides with the Anclote outage schedules.

**Q. Does the Anclote Gas Conversion Project remain on schedule to meet its targeted in-service date and total estimated cost?**

A. Yes. Unit 1 and Unit 2 gas conversions were completed on July 13, 2013 and December 2, 2013, respectively. DEF put the Unit 1 FD fan in service May 22, 2014 and expects the Unit 2 FD fan to be completed in December 2014. Total project costs are expected to be slightly lower than total estimated costs of $137 million.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

MICHAEL R. DELOWERY

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

August 22, 2014

**Q. Please state your name and business address.**

A. My name is Michael Delowery. My business address is 400 South Tryon Street, Charlotte, NC 28202.

**Q. Have you previously filed testimony before this Commission in Docket No. 140007-EI?**

A. Yes. I provided direct testimony on July 25, 2014.

**Q. Has your job description, education background or professional experience changed since that time?**

A. Yes. Effective August 16, 2014, I am now the Vice President of Project Management and Construction for Duke Energy. At the time of previous testimony I was in the same role but in an "acting" position.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide an update on the Mercury and Air Toxics Standards (MATS) - Anclote Gas Conversion Project (Project 17.1), specifically the projected costs that Duke Energy Florida (DEF or the Company) will incur on this project in 2015.

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

A. Yes. I am co-sponsoring the following portion of Exhibit No. __ (TGF-5) to Thomas G Foster's direct testimony:

- 42-5P page 20 of 21 - MATS - Anclote Gas Conversion

**Q. What are the estimated total project costs for the MATS – Anclote Gas Conversion Project (Project 17.1)?**

A. Total project costs are expected to be slightly lower than total estimated costs of $137 million.

**Q. What costs do you expect to incur in 2015 in connection with the MATS – Anclote Gas Conversion Project (Project 17.1)?**

A. DEF estimates project close-out costs of approximately $823k including site support, completion of punch list items, warranty support, document control/record management and contract close-out.

**Q. Does the Anclote Gas Conversion Project remain on schedule to meet its targeted in-service date?**

A. Yes. As stated in my July 25, 2014 direct testimony, Unit 1 and Unit 2 gas conversions went in service on July 13, 2013 and December 2, 2013, respectively. The Unit 1 Force Draft fan went in service May 22, 2014 and DEF still expects the Unit 2 fan to be in completed in December 2014.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

April 1, 2014

**Q. Please state your name and business address.**

A. My name is Jeffrey Swartz. My business address is 299 1st Avenue North, St. Petersburg, FL 33701.

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

A. I am employed by Duke Energy Florida (DEF) as Vice President – Power Generation Florida.

**Q. What are your responsibilities in that position?**

A. As Vice President of DEF's Power Generation organization, my responsibilities include overall leadership and strategic direction of DEF's power generation fleet. My major duties and responsibilities include strategic and tactical planning to operate and maintain DEF's non-nuclear generation fleet; generation fleet project and additions recommendations; major maintenance programs; outage and project management; retirement of generation facilities; asset allocation; workforce planning and staffing; organizational alignment and design; continuous business improvements; retention and inclusion; succession planning; and oversight of hundreds of employees and hundreds of millions of dollars in assets and capital and operating budgets.

**Q. Please describe your educational background and professional experience.**

A. I earned a Bachelor of Science degree in Mechanical Engineering from the United States Naval Academy 1985. I have 12 years of power plant and production experience in various managerial and executive positions within Duke Energy managing Fossil Steam Operations, Combustion Turbine Operations and Nuclear Plant Operations. While at Duke Energy I have managed new unit projects from construction to operations, and I have extensive contract negotiation and management experience. My prior experience also includes nuclear engineering and operations experience in the United States Navy and project management, engineering, supervisory and management experience with a pulp, paper and chemical manufacturing company.

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

A. Yes.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to explain material variances between actual and estimated/actual project expenditures for environmental compliance costs associated with DEF's Integrated Clean Air Compliance Program (Project 7.4) for the period January 2013 through December 2013.

**Q. How do actual O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections for the CAIR/CAMR Crystal River Program?**

A. The CAIR/CAMR Crystal River O&M variance is $5 million or 14% lower than projected. This variance is primarily attributable to $1.7 million lower than expected costs for CAIR Crystal River Project 7.4 – Base and $3.3 million lower than expected costs for CAIR Crystal River Project 7.4 - Energy.

**Q: Please explain the variance between actual project expenditures and the estimated/actual projections for the CAIR Crystal River Project – Base for the period January 2013 to December 2013?**

A: DEF's O&M costs for CAIR Crystal River Project – Base for 2013 were $1.7 million or 10% lower than projected. This variance is primary driven by $1.2 million lower FGD pond cleanout costs due to a miscalculation by the contractor of the density and amount of material to be removed in its bid proposal.

**Q. Please explain the variance between actual project expenditures and the estimated/actual projections for the CAIR Crystal River Project – Energy for the period January 2013 to December 2013?**

A. DEF's O&M costs for reagents and by-products for 2013 were $3.3 million or 19% lower than projected. This variance is primarily due to a $2 million gypsum variance as a result of lower than expected disposal volume and reduced sales expense, and a $1.3 million limestone variance driven by favorable pricing terms in new supply and trucking contracts.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>JEFFREY SWARTZ</u>

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

July 25, 2014

**Q. Please state your name and business address.**

A. My name is Jeffrey Swartz. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

**Q. Have you previously filed testimony before this Commission in Docket No. 140007-EI?**

A: Yes, I provided direct testimony on April 1, 2014.

**Q: Has your job description, education background and professional experience changed since that time?**

A: No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to explain material variances between 2014 estimated/actual cost projections and original 2014 cost projections for compliance costs associated with FPSC-approved environmental programs under my responsibility including Duke Energy Florida's (DEF) Integrated Clean Air Compliance Program (Project 7.4) and Mercury & Air Toxics Standards (MATS) – Crystal River 1&2 Program (Project 17.2).

**Q. How do the estimated/actual O&M project expenditures compare with original projections for the CAIR Crystal River (CR) Program (Project 7.4) for the period January 2014 to December 2014?**

A. O&M expenditures are expected to be approximately $2.9 million or 8% lower than originally projected. This variance is primarily driven by a $946k or 6% increase in CAIR Crystal River Project 7.4 – Base and $3.7 million or 20% decrease in CAIR Crystal River Project 7.4 – Energy.

**Q. Please explain the variance between the estimated/actual O&M project expenditures and original projections for the CAIR Crystal River Program (Project 7.4 – Base) for the period January 2014 to December 2014.**

A. The $946k increase consists of higher base routine CAIR project and CR Unit 5 Spring outage costs as explained below.

DEF expects a $269k increase in labor costs associated with operating the hydrated lime system that were not known at the time of the 2014 Projection Filing.

DEF expects a $215k increase in materials due to emergent costs associated with the repair of the absorber mixers.

DEF expects a $162k increase in contractor costs due to additional work to repair the Selective Catalytic Reduction vacuum line and emergent repairs to lift bars for all three ball mills.

DEF expects $262k in base routine CAIR project costs that were not known at the time of the 2014 Projection Filing.

DEF incurred a $34k increase in labor and materials to complete the CR Unit 5 Spring outage.

**Q. Please explain the variance between the estimated/actual O&M project expenditures and original projections for the CAIR Crystal River Program (Project 7.4 – Energy) for the period January 2014 to December 2014.**

A. The $3.7 million decrease is due to $1.6 million lower limestone costs and $3.3 million lower gypsum costs offset by $966k higher hydrated lime costs. Lower limestone costs are a result of reduced rates in newly negotiated contracts. Lower gypsum costs are driven by reduced disposal costs. Increased hydrated lime costs are due to increased usage from higher injection rates necessary to meet Sulfuric Acid Mist permit requirements.

**Q. How do the estimated/actual capital project expenditures compare with original projections for the CAIR/CAMR Crystal River Program (Project 7.4) for the period January 2014 to December 2014?**

A. Capital expenditures are expected to be $2.4 million or 76% lower than originally projected. This difference primarily consists of $92k higher Reclaim Water Reuse project costs, $2 million lower Flue Gas Desulfurization (FGD) Blowdown Treatment project costs, and $519k lower Crystal River Unit 5 Clinker Mitigation project costs as explained below.

$92k higher Reclaim Water Reuse costs are due to the purchase of necessary fiber optics not included in the original work scope.

$2 million lower FGD Blowdown Treatment costs are due to a change in strategy to comply with FDEP wastewater permit conditions. Test wells will no longer be installed to evaluate a potential Deep Well Injection system.

$519k lower Clinker Mitigation costs are due to purchasing materials in 2013 leading up to the CR Unit 5 2014 Spring outage, and the ability to use the same drawings from the CR Unit 4 Clinker Mitigation project to avoid additional engineering work.

**Q: Please explain the variance between the estimated/actual O&M project expenditures and original projections for the MATS – CR 1&2 Program (Project 17.2) for the period January 2014 to December 2014.**

A: DEF has implemented its plan as outlined in Order No. PSC-14-0713-PAA-EI to use coal with lower levels of sulfur, mercury, and chlorine, install dry sorbent and activated carbon injection systems, and enhance the electrostatic precipitators to operate in compliance with MATS. O&M expenditures for the MATS – CR1&2 Program are expected to be $4.4 million higher than the originally projected O&M costs of $1.1 million to perform alternative coal trials.

**Q: Please explain the variance between the estimated/actual capital project expenditures and original projections for the MATS – CR 1&2 Program (Project 17.2) for the period January 2014 to December 2014.**

A: As stated in my October 7, 2013 Direct Testimony in Docket No. 130007-EI, there were no MATS CR1&2 capital costs included in the 2014 cost projections as the results of alternative coal testing were unknown at that time. As explained for O&M above, DEF expects to incur capital costs to make operational changes to CR1&2 to successfully burn alternative coal to comply with MATS. Therefore, capital expenditures for the MATS – CR1&2 Program are expected to be $6.9 million higher than originally projected.

**Q: Is the MATS – CR1&2 Program on schedule to meet its target in-service date and total estimated costs?**

A: Yes. The MATS-CR1&2 Program is expected to be completed by April 2016 at a total cost of $28 million.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

AUGUST 22, 2014

**Q. Please state your name and business address.**

A. My name is Jeffrey Swartz. My business address is 299 1st Avenue North, St. Petersburg, FL 33701.

**Q. Have you previously filed testimony before this Commission in Docket No. 140007-EI?**

A. Yes. I provided direct testimony on April 1, 2014 and July 25, 2014.

**Q. Has your job description, education background or professional experience changed since that time?**

A. No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide estimates of costs that will be incurred in 2015 for Duke Energy Florida's (DEF or Company) Integrated Clean

Air Compliance Program (Project 7.4) and Mercury and Air Toxics Standards (MATS) Program – Crystal River Units 1 & 2 (CR1&2) (Project 17.2).

**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.__ (JS-1), which is an organization chart for DEF's Crystal River Clean Air Projects. I am also co-sponsoring the following portions of Exhibit No. __ (TGF-5) to Thomas G. Foster's direct testimony:

- 42-5P page 7 of 21 – Clean Air Interstate Rule (CAIR)
- 42-5P page 21 of 21 – MATS Program – CR1&2

**Q. What O&M costs does DEF expect to incur in 2015 for air emission controls at Crystal River Units 4 and 5 (CR4&5) as part of the Integrated Clean Air Compliance Program (Project 7.4)?**

A. DEF estimates O&M costs of approximately $29 million to support the operation and maintenance of air emissions controls that were installed at the Crystal River Energy Complex as outlined in DEF's Integrated Clean Air Compliance Plan as follows:

- Labor costs are estimated at approximately $7.9 million based on current staffing levels. Contractor expenses are estimated at approximately $3.9 million for various services.
- Parts and materials are estimated at approximately $1.9 million.
- Other costs are estimated at approximately $0.7 million.

- Project expenses for absorber recycle pump overhaul, vacuum filter pump motor, oxidation air blower, absorber agitator shaft replacement and Flue Gas Desulfurization blowdown wastewater treatment are estimated at approximately $0.5 million.
- CR5 outage costs are estimated at approximately $1.2 million.
- Reagent costs (ammonia, limestone, dibasic acid, hydrated lime, caustic and net gypsum sales/disposal) are estimated to total approximately $12.9 million.

**Q. What capital costs does DEF expect to incur in 2015 for the implementation of the Integrated Clean Air Compliance Program (Project 7.4)?**

A. DEF estimates capital costs of approximately $25k for the reclaim water reuse system project. This is an alternative water project to comply with the Conditions of Site Certification requirements regarding the rolling annual average daily withdrawal rate of groundwater from CR4&5.

**Q. What steps does DEF take to ensure that the level of expenditures for the operation of CR4&5 controls is reasonable and prudent?**

A. Plant management monitors and controls costs by several methods. Work is scheduled and conducted proactively and efficiently. Expenditures are reviewed and approved by the appropriate level of management per existing Company policies. All expenditures are monitored on a monthly basis and budget variances are analyzed for accuracy and appropriateness.

**Q. Please discuss the organization being used to operate and maintain the CAIR equipment?**

A. The Company established a dedicated unit to manage, operate and maintain the CAIR equipment as shown by the organization chart on Exhibit__(JS-1). This unit consists of 58 employees that report to the Crystal River Energy Complex station manager and 1 employee who reports to the Director Florida ES Finance. There are 8 managers and 50 maintenance, operations and support employees. The operators work rotating shifts in order to staff the operations of the facility 24 hours per day. The maintenance employees primarily work days but shift employees are available to work when needed. In an effort to keep regular staffing levels low, contractors are used for specialized or lower-skilled work which minimizes overall operations and maintenance costs.

**Q. Are there policies and procedures in place to efficiently operate and maintain the CAIR equipment?**

A. Yes. There are several different policies and procedures used to efficiently operate and maintain the CAIR equipment. First and foremost, the plant adheres to all OSHA and Company safety-related policies and procedures. It also follows operations and maintenance procedures during startups, shut downs, steady state situations and transient scenarios. All employees are trained to respond effectively to many different operating scenarios as part of these procedures. The operating and maintenance procedures were developed during construction and startup, and continue to be revised as more experience and expertise is gained with the equipment.

The plant uses existing corporate-wide policies and procedures to efficiently conduct business such as human resources (hiring, compensation, and performance management), supply chain management (purchasing, contracting, and inventory) and information technology (NERC Critical Infrastructure Protection).

**Q. Are personnel operating and maintaining this equipment trained in these policies and procedures?**

A. Yes. Personnel selected to operate and maintain CAIR equipment have to meet job-related qualifications for specific positions. Some operation employees are hired from outside companies and have previous experience operating this type equipment at other utilities. Other operation employees are selected to participate in an in-house apprentice program. These employees must complete a 2 to 4 year training program before they are fully qualified workers. This training includes a mix of classroom and hands-on training that helps employees progress through different levels of task proficiency. Maintenance employees are selected based on their skills and experience, and are provided equipment specific training to optimize equipment maintenance.

Equipment-specific training was conducted during the construction and start-up phase of the project and continues as major equipment overhauls are performed.

This training included equipment walk-downs, discussions with vendor representatives and hands-on operating and maintenance work performed under the supervision of qualified individuals.

From a business process standpoint, CAIR employees are trained on policies and procedures using several different methods that include required reading and review of the policies and procedures, small group discussions, one-on-one interaction with subject matter experts, computer based training and on the job task training.

**Q. Does the Company have controls in place to ensure these policies and procedures are followed?**

A. DEF ensures compliance with policies and procedures through management controls, equipment round checklists, procedure sign-offs and internal audits. The level of controls is based on the particular policy or procedure.

**Q. Are there any other mechanisms in place to ensure proper operation and maintenance of CAIR equipment?**

A. Along with the above methods, prudent engineering judgment and industry standards are used to ensure proper operation and maintenance of CAIR equipment. The FGD Engineer (System Owner) works directly with operations and maintenance personnel to ensure that systems are working in accordance with design parameters.

Routine maintenance is performed on a regular and on-going basis. In addition, specialized inspection and maintenance work is conducted during scheduled unit and equipment outages. These specialized work activities are identified and refined as the Company gains more operational experience with the equipment.

**Q. What O&M costs does DEF expect to incur in 2015 for the MATS Program – CR1&2 (Project 17.2)?**

A. DEF estimates O&M costs of approximately $3.8 million to implement the CR1&2 MATS Compliance Plan as approved by the Commission in Order PSC-14-0173-PAA-EI. These costs include electrostatic precipitator (ESP) projects, combustion optimization and emission testing.

ESP projects include redistribution of flue gas flow within the ESPs, adjustment of mechanical rapper connections, optimization of rapping programs, and modifications associated with the installation of high frequency power supplies.

Combustion optimization includes contractor costs for an engineering assessment, and tuning activities to maximize boiler efficiency and minimize flue gas flow.

Emissions testing includes contractor costs for stack testing, coal analysis and ash analysis for alternate coal test burns.

**Q. What capital costs does DEF expect to incur in 2015 for the MATS Program – CR1&2 (Project 17.2)?**

A. DEF estimates capital costs of approximately $10.8 million to implement the CR1&2 MATS Compliance Plan in Order PSC-14-0173-PAA-EI. These costs include reagent systems, ESP projects and plant systems projects.

Two reagent systems, dry sorbent injection and activated carbon injection, common to CR1&2 will be installed.

ESP projects include installation of high frequency power supplies, hopper high level indicators, hopper vibrators and ash conditioning technology.

Plant systems projects include installation of CO monitors, economizer soot blowers, Appendix K sorbent traps for mercury monitoring, particulate matter continuous emissions monitoring systems and modifications to the fuel handling systems.

**Q. What is the current status of the CR1&2 MATS Compliance Plan?**

A. DEF is on target to complete the CR1&2 Compliance Plan by April 2016 at a total cost of $28M.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

April 1, 2014

**Q. Please state your name and business address.**

A. My name is Patricia Q. West. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

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

A. I am employed by the Environmental Services and Strategy Department of Duke Energy Florida (DEF) as Manager of Generation Environmental Field Support Services.

**Q. What are your responsibilities in that position?**

A. Currently, my responsibilities include ensuring that environmental technical and regulatory support is provided during the development and implementation of environmental compliance strategies for power generation facilities in Florida.

**Q. Please describe your educational background and professional experience.**

A. I obtained my Bachelor of Arts degree in Biology from New College of the University of South Florida in 1983. I was employed by the Polk County Health Department between 1983 and 1986 and by the Florida Department of Environmental Protection (FDEP) from 1986 - 1990. At the FDEP, I was involved in compliance and enforcement efforts associated with petroleum storage facilities. I joined Florida Power Corporation in 1990 as an Environmental Project Manager and then held progressively more responsible positions through the merger with Carolina Power and Light, and more recently through the merger with Duke Energy when I assumed my current position as Manager of Generation Environmental Field Support Services.

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

A. Yes.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to explain material variances between the actual and estimated/actual project expenditures for environmental compliance costs associated with DEF's Pipeline Integrity Management (PIM) Program (Project 3), CAIR/CAMR – Peaking (Project 7.2), Best Available Retrofit Technology (BART) (Project 7.5), Arsenic Groundwater Standard (Project 8), National Pollutant Discharge Elimination System (NPDES) (Project 16), Mercury & Air Toxics Standards (MATS) – CR 4&5 (Project 17) and MATS – CR1&2 (Project 17.2) for the period January 2013 through December 2013. In addition, I am sponsoring Exhibit No. __ (PQW-1), DEF's review of the efficacy of its Integrated Clean Air Compliance Plan and retrofit options in relation to expected environmental regulations.

**Q. How did actual O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections for the PIM Project?**

A. The PIM O&M variance is $28,414 or 8% higher than projected due to an under-estimation of costs associated with required Florida Department of Environmental Transportation projects.

**Q. How did actual O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections for the CAIR/CAMR – Peaking Project?**

A: The CAIR/CAMR – Peaking variance is $5,402 or 5% lower than projected due to a portion of the emissions testing at the Bartow CT being deferred to 2014.

**Q. How did actual capital and O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections for the BART Project?**

A. The BART capital spend variance is $12,345 or 100% higher than projected. This variance is attributable to the purchase and installation of hardware necessary to measure electrostatic precipitator (ESP) power levels to provide information required by the Compliance Assurance Monitoring (CAM) Plan associated with the particulate matter (PM) limit of the Title V Air Operating Permit.

The BART O&M variance is $1,469 or 35% lower than projected primarily due to a contingency amount for BART SO2 monitoring that was not required as expected as it was already part of routine air emissions monitoring.

**Q. How did actual O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections for the Arsenic Groundwater Standard Project?**

A. The Arsenic Groundwater Monitoring variance is $12,911 or 61% lower than projected due to receipt of the FDEP's response to the Arsenic Plan of Study later than expected. The Plan was submitted to the agency on April 26, 2013 and a response was originally expected during the second or third quarter of 2013, however, it was received on December 23, 2013. Arsenic work will continue into 2014.

**Q. How did actual capital and O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections for the NPDES Project?**

A. The NPDES capital spend variance is $3.3 million or 35 % lower than projected due to the need for additional project review and approval during the final design process associated with tank re-purposing. This delay resulted in work originally scheduled for 2013 to transition to 2014.

The NPDES O&M variance is $44,942 or 12% lower than projected due to project costs being less than expected during 2013. Some costs may move into 2014 depending on the FDEP's feedback on the Suwannee Copper Study Plan Report that is expected to be submitted to the agency by the end of the first quarter 2014.

**Q. How did actual O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections for the MATS – CR4&5 Project?**

A. The MATS – CR4&5 O&M variance is $91,095 or 46% lower than projected primarily due to $78,749 of expenses inadvertently charged to the MATS – CR4&5 capital ECRC project versus the MATS – CR4&5 O&M ECRC project. An accounting entry was done the 1st quarter 2014 to transfer the charges.

**Q. How did actual O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections for the MATS – CR1&2 Project?**

A. The MATS – CR1&2 O&M variance is $151,134 or 19% higher than projected due to the installation of a temporary Activated Carbon Injection (ACI) system on Crystal River Units 1 & 2 that was not anticipated in the 2013 Estimated/Actual Filing. This system was utilized during the alternative fuel trials to evaluate the mercury reduction potential of ACI.

**Q. In Order No. PSC 10-0683 -FOF-EI issued in Docket 100007-EI on November 15, 2010, the Commission directed DEF to file as part of its ECRC true-up testimony a yearly review of the efficacy of its Plan D and the cost-effectiveness of DEF's retrofit options for each generating unit in relation to expected changes in environmental regulations. Has DEF conducted such a review?**

A. Yes. DEF's yearly review of the Integrated Clean Air Compliance Plan is provided as Exhibit No. __ (PQW-1).

**Q. Please summarize the conclusions of DEF's review of its Integrated Clean Air Compliance Plan.**

A: DEF installed emission controls contemplated in its Integrated Clean Air Compliance Plan on time and within budget. The Flue Gas Desulfurization (wet scrubbers) and Selective Catalytic Reduction systems on Crystal River Units 4 & 5 have enabled DEF to comply with CAIR requirements and will continue to be the cornerstone of DEF's integrated air quality compliance strategy. DEF is confident that the Integrated Clean Air Compliance Plan, along with compliance strategies under development, will enable it to achieve and maintain compliance with applicable regulations, including MATS, in a cost effective manner. DEF continues to evaluate additional MATS compliance options and other regulatory developments affecting fossil-fired electric generating units. The results of analysis performed to date are included in my Exhibit No. __ (PQW-1).

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

July 25, 2014

**Q. Please state your name and business address.**

A. My name is Patricia Q. West. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

**Q. Have you previously filed testimony before this Commission in Docket No. 140007-EI?**

A: Yes, I provided direct testimony on April 1, 2014.

**Q: Has your job description, education, background, and professional experience changed since that time?**

A: No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to explain material variances between 2014 estimated/actual cost projections and original 2014 cost projections for environmental compliance costs associated with FPSC–approved programs under my responsibility. These programs include Pipeline Integrity Management (PIM) (Project 3), Above Ground Secondary Containment (Project 4), Phase II Cooling Water Intake – 316(b) (Project 6), CAIR/CAMR - Peaking (Project 7.2), Best Available Retrofit Technology (BART) (Project 7.5), Arsenic Groundwater Standard (Project 8), Underground Storage Tanks (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge Permanent Cooling Tower (Project 11.1), Greenhouse Gas Inventory and Reporting (Project 12), Mercury Total Daily Maximum Loads Monitoring (Project 13), Hazardous Air Pollutants Information Collection Request (ICR) Program (Project 14), Effluent Limitation Guidelines ICR Program (Project 15), National Pollutant Discharge Elimination System (NPDES) (Project 16) and Mercury and Air Toxics Standards (MATS) – Crystal River (CR) 4&5 (Project 17) for the period January 2014 through December 2014.

**Q: Please explain the variance between estimated/actual project expenditures and original projections for PIM (Project 3) for the period January 2014 to December 2014.**

A: O&M expenditures for PIM are expected to be $42k or 11% higher than originally projected due to the expectation that the Bartow to Anclote pipeline would be sold or retired in mid-2014. Based on an evaluation of possible disposition options, it was subsequently determined that Duke Energy Florida (DEF) would pursue a sale to a third party late in 2014 or 2015. Until that time, DEF has to continue the PIM program to maintain pipeline integrity and adhere to regulatory requirements.

**Q: What is the current status of the pipeline disposition?**

A: DEF is actively marketing the pipeline to interested parties. If DEF cannot execute a sale to a third party it will then consider retiring the pipeline.

**Q: Please explain the variance between estimated/actual project expenditures and original projections for 316(b) (Project 6) for period January 2014 to December 2014.**

A: O&M expenditures for 316(b) are expected to be $690k or 86% lower than originally projected due to an EPA delay involving reissuance of the final 316(b) rule to May 19, 2014, as well as a revised schedule for required studies contained in the final rule.

**Q: Please explain the variance between estimated/actual project expenditures and original projections for BART (Project 7.5) for the period January 2014 to December 2014.**

A: O&M expenditures for BART are expected to be $3k or 100% lower than originally projected due to an accounting adjustment to reverse Title V and NPDES legal expenses erroneously charged to the BART project in 2013.

**Q: Please explain the variance between estimated/actual project expenditures and original projections for Arsenic Groundwater Standard (Project 8) for the period January 2014 to December 2014.**

A: O&M expenditures for Arsenic Groundwater Standard are expected to be $31k or 77% lower than originally projected as the FDEP has extended arsenic sampling another year to determine if background concentrations are driving elevated levels delaying resolution efforts to 2015.

**Q: Please explain the variance between estimated/actual project expenditures and original projections for NPDES (Project 16) capital for the period January 2014 to December 2014.**

A: Capital expenditures in 2014 for the NPDES project are expected to be $4.9 million higher than originally projected due to cash flow shift from 2013 to 2014, change in tank cleaning and repurposing contractors, and additional internal tank work to ensure selected coating adheres to the tank surfaces.

In 2013, DEF evaluated current and planned waste water flows for the Bartow Plant. This evaluation resulted in a shift of approximately $3.4 million in NPDES project costs from 2013 to 2014.

In 2014, DEF replaced the contractor performing tank cleaning and repurposing work associated with the NPDES project. As part of this changeover, the new contractor had to complete removal and offsite disposal of #6 oil in the tank bottoms prior to commencing repurposing. It is also necessary to use equipment to maintain internal climate control due to high humidity and temperatures. DEF is completing a final evaluation of coating requirements.

The project is on target to be in-service in December 2014 in compliance with the FDEP Administrative Order associated with the NPDES permit.

**Q: Please explain the variance between estimated/actual project expenditures and original projections for MATS – CR4&5 (Project 17) O&M for the period January 2014 to December 2014.**

A: O&M expenditures for MATS – Crystal River Units 4&5 (CR4&5) are expected to be $142k or 35% lower than originally projected. This variance is primarily due to a decreases of $190k in mercury re-emission chemical system and $100k in particulate matter (PM) continuous emissions monitoring system costs due to installation delays offset by a $123k increase in Appendix K mercury monitoring costs and the addition of a mercury characterization study for $25k in 2014. The mercury characterization study consists of stack testing and lab analyses to evaluate impacts on mercury emissions from scrubber chemistry and startup conditions.

**Q: Please explain the variance between estimated/actual project expenditures and original projections for MATS – CR4&5 (Project 17) capital for the period January 2014 to December 2014.**

A: Capital expenditures for MATS – CR4&5 are expected to be $2.9 million lower than originally projected. The variance is due to $3 million of mercury re-emission chemical system installation costs pushed to 2015 offset by an additional $60k necessary to install oxidation reduction potential probes for monitoring flue gas desulfurization chemistry.

**Q: Please provide an update of Best Available Retrofit Technology (BART) regulations.**

A: In 2012, DEF worked with the FDEP to develop and finalize specific BART permits to address $SO_2$ and NOx requirements for Crystal River Units 1&2 (CR 1&2). The FDEP subsequently submitted to the EPA a revised State Implementation Plan (SIP) containing unit-specific BART determinations for CR1&2. The $SO_2$ and NOx BART permits for these units require installation of dry flue gas desulfurization and selective catalytic reduction by December 31, 2017, or alternatively the discontinuation of the use of coal in these units by December 31, 2020. On April 30, 2013, DEF provided notice to the FDEP that it decided to cease burning coal in CR1&2 by December 31, 2020. The EPA formally approved FDEP's revised SIP in August 2013.

With regard to particulate matter (PM) and opacity emissions, the revised BART requirements for these parameters contained in the previously issued air construction permit (Air Permit No. 0170004-017-AC) became effective on January 1, 2014. The provisions of the air construction permit were incorporated into a revised Title V Operating Permit (Permit No. 0170004-043-AV) that became effective on June 22, 2014. The revised Title V permit also contains an updated / revised version of the Compliance Assurance Monitoring Plan, incorporating provisions required by the terms of the PM BART air construction permit.

The actions / decisions noted above are expected to fulfill DEF's obligations under the BART regulations for the remaining life of CR1&2.

**Q: Please provide an update of 316(b) regulations.**

A: On May 19, 2014, the EPA Administrator signed a final 316(b) rule to protect fish and aquatic life drawn into cooling systems at power plants and factories. The rule aims to minimize impingement (aquatic life pinned against cooling water intake structures) and entrainment (aquatic life drawn into cooling water systems). The regulation is effective 60 days after publication in the Federal Register, which is expected in August 2014.

The regulation primarily applies to facilities that commenced construction prior to or on January 17, 2002, and to new units at existing facilities that are built to increase the generating capacity of the facility. All facilities that withdraw greater than 2 million gallons per day from waters of the U.S. and where 25% of the withdrawn water is used for cooling purposes are subject to the regulation.

Per the final rule, required 316(b) studies and information submittals will be tied to NPDES permit renewals. For permits that expire within 45 months of the effective date of the final rule, certain information must be submitted with the renewal application. Other information, including field study results, will be required to be submitted pursuant to a schedule included in the re-issued NPDES permit.

For NPDES permits that expire more than 45 months from the effective date of the rule, all information, including study results, is required to be submitted as part of the renewal application.

DEF is currently evaluating the 316(b) rule to determine potential study requirements, operating and cost impacts to its generating stations.

**Q: Please provide an update on Carbon Regulations recently proposed by the EPA.**

A: On June 18, 2014, the EPA published the proposed New Source Performance Standards for Greenhouse Gas emissions from existing fossil fuel-fired electric generating units. Comments on the proposal are due by October 16, 2014 and a final rule is expected in June 2015. The EPA is proposing state-specific average $CO_2$ emission rate standards that the EPA estimates will reduce total power sector emissions nationally by 30 percent from 2005 levels in 2030. For each state, the EPA used 2012 generation data as a baseline to calculate a 2012 average fossil-fueled emission rate that served as a starting point for the development of the standards. The EPA then made adjustments downward from that rate to develop two standards: one for the period 2020-2029 and the other for 2030 and beyond. DEF is reviewing the proposed rule, and will work with other state utilities and the FDEP to develop Florida-specific comments and supporting information. DEF expects to incur no ECRC costs in 2014 related to this rule.

**Q: Please provide an update on the Cross State Air Pollution Rule (CSAPR).**

A: CSAPR was vacated by the D.C. Circuit Court of Appeals in 2012 which had the effect of leaving CAIR as the governing rule. The EPA appealed this decision to the U.S. Supreme Court and on April 29, 2014, it overturned the D.C. Circuit Court's ruling. Currently, the CSAPR is back at the D.C. Circuit Court for further proceedings. The EPA has petitioned the court to lift the stay of the CSAPR and reinstate the rule beginning January 1, 2015. Following a to-be-issued revised order from the D.C. Circuit Court, the EPA will need to develop an implementation schedule to transition CAIR to CSAPR. In the meantime CAIR remains in effect. In parallel, the EPA plans to propose a replacement CSAPR rule late in 2014.

**Q: Please provide an update on the National Ambient Air Quality Standards?**

A: The EPA set new 1 hour health-based $NO_2$ and $SO_2$ standards in 2010. In mid-2013, the EPA finalized $SO_2$ non-attainment designations for two small areas in Florida outside DEF's service territory. The EPA deferred making any other designations until late 2017. On April 24, 2014, the EPA released a proposed rule that will establish requirements for additional ambient air quality monitoring and/or modeling that will be used for future area designations.

The EPA was to have completed a review of the ozone NAAQS in 2013. On April 29, 2014, the Court of the Northern District of California ruled in favor of a schedule proposed by the Sierra Club requiring the EPA to issue a proposed rule no later than December 1, 2014, and a final rule no later than October 1, 2015.

**Q: Please provide an update on the Steam Effluent Limitation Guidelines.**

A: On April 8, 2014, the EPA acknowledged the need to closely coordinate this rule, which regulates waste streams from power plants, with the Coal Combustion Residual (CCR) rule, which will regulate landfills and ash basins. The final CCR rule is expected by December 19, 2014. The deadline for the EPA to issue the final Steam Effluent Limitations Guidelines has been extended to September 30, 2015.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

AUGUST 22, 2014

**Q. Please state your name and business address.**

A. My name is Patricia Q. West. My business address is 299 1st Avenue North, St. Petersburg, FL 33701.

**Q. Have you previously filed testimony before this Commission in Docket No. 140007-EI?**

A: Yes. I provided direct testimony on April 1, 2014 and July 25, 2014.

**Q. Has your job description, education, background or professional experience changed since that time?**

A. No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide estimates of the costs that will be incurred in the year 2015 for Duke Energy Florida's (DEF or Company) Pipeline Integrity Management (PIM) (Project 3), Above Ground Storage Tanks

(AST) (Project 4), Phase II Cooling Water Intake (Project 6), CAIR/CAMR Continuous Mercury Monitoring System (CMMS) (Projects 7.2 & 7.3), Best Available Retrofit Technology (BART) (Project 7.5), Arsenic Groundwater Standard (Project 8), Underground Storage Tanks (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge Permanent Cooling Tower (Project 11.1), Greenhouse Gas Inventory and Reporting (Project 12), Mercury Total Maximum Loads Monitoring (TMDL) (Project 13), Hazardous Air Pollutants (HAPs) Information Collection Request (ICR) (Project 14), Effluent Limitation Guidelines ICR (Project 15), National Pollutant Discharge Elimination System (NPDES) Program (Project 16), and Mercury & Air Toxics Standards (MATS) Program – Crystal River Units 4 & 5 (CR4&5) (Project 17).

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

**A.** Yes. I am co-sponsoring the following portions of Exhibit No. __(TGF-5) to Thomas G Foster's direct testimony:

- 42-5P page 3 of 21 – PIM
- 42-5P page 4 of 21 - AST
- 42-5P page 6 of 21 - Phase II Cooling Water Intake
- 42-5P page 7 of 21 – Clean Air Interstate Rule (CAIR)
- 42-5P page 8 of 21 – BART
- 42-5P page 9 of 21 - Arsenic Groundwater Standard
- 42-5P page 11 of 21 - Underground Storage Tanks
- 42-5P page 12 of 21 - Modular Cooling Towers

- 42-5P page 13 of 21 - Thermal Discharge Permanent Cooling Tower
- 42-5P page 14 of 21 - Greenhouse Gas Inventory and Reporting
- 42-5P page 15 of 21 - Mercury TMDL
- 42-5P page 16 of 21 - HAPs ICR
- 42-5P page 17 of 21 - Effluent Limitation Guidelines ICR Program
- 42-5P page 18 of 21 - NPDES
- 42-5P page 19 of 21 - MATS – CR4&5

**Q. What costs does DEF expect to incur in 2015 for the PIM Program (Project 3)?**

A. DEF estimates O&M costs of approximately $498k for the Pipeline Integrity Management Program to comply with the PIM regulations (49 CFR Part 195). These costs include general program management and oversight of the performance of program activities.

**Q. What costs does DEF expect to incur in 2015 for the AST Program (Project 4)?**

A. DEF does not expect any expenditures in 2015.

**Q. What costs does DEF expect to incur in 2015 for the Phase II Cooling Water Intake Program (Project 6)?**

A. DEF estimates O&M costs of $320k for the Phase II Cooling Water Intake Program to evaluate compliance with the 316(b) rule dated May 19, 2014.

**Q. What costs does DEF expect to incur in 2015 for the CAIR / CAMR Program (Project 7.2)?**

A. DEF estimates O&M costs of approximately $47k for the CAIR/CAMR Program for data acquisition system maintenance of combustion turbine units and 40 CFR 75, Appendix E, Section 2.2 air emissions compliance testing. This regulation requires the Company to perform air emissions testing to reset correlation curves every 20 quarters and must be performed on all of its Predictive Emissions Monitoring Systems (PEMS).

**Q. What costs does DEF expect to incur in 2015 for the BART Program (Project 7.5)?**

A: DEF does not expect any expenditures in 2015.

**Q. What costs does DEF expect to incur in 2015 for the Arsenic Groundwater Standard Program (Project 8)?**

A. DEF estimates O&M costs of approximately $16k for the Arsenic Groundwater Standard Program to analyze monitoring well data and prepare a report for FDEP submittal.

**Q. What costs does DEF expect to incur in 2015 for the Underground Storage Tanks Program (Project 10)?**

A. DEF does not expect any expenditures in 2015.

**Q. What costs does DEF expect to incur in 2015 for the Modular Cooling Tower Program (Project 11)?**

A. DEF does not expect any expenditures in 2015.

**Q. What costs does DEF expect to incur in 2015 for the Thermal Discharge Permanent Cooling Tower (Project 11.1)?**

A. DEF does not expect any expenditures in 2015.

**Q. What costs does DEF expect to incur in 2015 for the Greenhouse Gas Inventory and Reporting Program (Project 12)?**

**A.** DEF does not expect any expenditures in 2015.

**Q. What costs does DEF expect to incur in 2015 for the Mercury TMDL Program (Project 13)?**

A. DEF does not expect any expenditures in 2015.

**Q. What costs does DEF expect to incur in 2015 in for the Hazardous Air Pollutants Information Collection Request Program (Project No. 14)?**

A. DEF does not expect any expenditures in 2015.

**Q. What costs does DEF expect to incur in 2015 for the Effluent Limitation Guidelines ICR Program (Project No. 15)?**

A. DEF does not expect any expenditures in 2015.

**Q. What costs does DEF expect to incur in 2015 for the NPDES Program (Project No. 16)?**

A. DEF estimates O&M costs of approximately $271k to continue biological monitoring for the Phase II thermal evaluation at Anclote and Bartow and whole effluent toxicity testing at Anclote, Bartow, and CR4&5 to comply with NPDES permits. Capital expenditures are expected to be approximately $31k to complete the Bartow freeboard project.

**Q. What O&M costs does DEF expect to incur in 2015 for the MATS Program – CR4&5 (Project No. 17)?**

A. DEF estimates O&M costs of approximately $432k for CR4&5 MATS compliance for Appendix K monitoring, mercury re-emission chemical system, particulate matter (PM) continuous emissions monitoring systems (CEMS), mercury trim-ready set-up, MATS work practice standards, and mercury characterization study.

Appendix K monitoring includes contractor costs associated with the maintenance and chemical analysis of sorbent traps that will be used to monitor mercury emissions on CR4&5 for MATS compliance.

The mercury re-emission chemical system is an injection skid that will be used to suppress mercury re-emission from the wet scrubbers at CR4&5. The chemical additive will be injected into the scrubber on an as-needed basis, primarily following unit startups.

PM CEMS includes contractor costs associated with maintaining the CEMS equipment, which will be used to continuously monitor PM emissions on CR4&5 for MATS compliance.

Mercury trim-ready setup includes costs associated with engineering design and permitting for a fuel additive system. An oxidation-enhancing chemical will be added to the fuel on an as-needed basis to improve the mercury capture efficiency of the scrubber.

MATS work practice standards includes costs associated with combustion tuning activities that must be performed for MATS compliance.

The mercury characterization study consists of stack testing and lab analysis to evaluate impacts on mercury emissions from scrubber chemistry and startup conditions.

**Q. What capital costs does DEF expect to incur in 2015 for the MATS Program – CR4&5 (Project No. 17)?**

A. DEF estimates **c**apital costs of approximately $1.5 million for installation of the mercury re-emission chemical system. As stated above, this system is an injection skid that will be used to suppress mercury re-emission from the wet scrubbers at CR4&5.

**Q. Is DEF requesting recovery of costs for any new environmental programs?**

A. No.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>COREY ZEIGLER</u>

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

April 1, 2014

**Q. Please state your name and business address.**

A. My name is Corey Zeigler. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida (DEF) as the Manager Environmental Health and Safety for Transmission and Distribution.

**Q. What are your responsibilities in that position?**

A. Currently, my responsibilities include providing oversight and subject matter expert resources to the Transmission and Distribution Business Units for managing Environmental Health and Safety (EH&S) compliance.

**Q. Please describe your educational background and professional experience.**

A. I received a Bachelor of Science degree in General Business Administration and Management from the University of South Florida. Prior to my current EH&S Manager role, I was the Environmental Permitting and Compliance Manager for Energy Delivery. I have 23 years of experience in the utility industry holding various operational, supervisor and managerial roles at DEF.

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

A. Yes.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to explain material variances between actual and estimated/actual project expenditures for environmental compliance costs associated with DEF's Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Project 1 & 1a), Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2) and Sea Turtle Coastal Street Lighting Program (Project 9) for the period January 2013 through December 2013.

**Q. How did actual O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections as presented in previous testimony and exhibits for the Substation System Program?**

A. The project expenditure variance for the Substation System Program is $438,593 or 11% lower than projected. This variance is attributable to the inability to conduct scheduled remediation at some substation sites during the course of 2013. Several sites could not be remediated pending repairs and construction activities. In addition, a re-grading project at the Windermere substation was delayed due to an ongoing issue at the site retaining water during rain events throughout the year.

**Q. How did actual O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections as presented in previous testimony and exhibits for the Distribution System Program?**

A. The project expenditure variance for the Distribution System Program is $4,652 or 4% higher than projected due to unexpected deviations at the TRIP sites. A total of five remaining transformer sites were scheduled for abatement work in 2013 of which two were completed. Of the five sites, three required monitoring wells, one required additional soil sampling and one is pending further sampling based on clean-up criteria in the TRIP Environmental Remediation Strategy. Natural attenuation monitoring was implemented at two of the uncompleted sites. DEF is waiting for owner consent to install a monitoring well at the third site.

**Q. How did actual O&M expenditures for January 2013 through December 2013 compare with DEF's estimated/actual projections as presented in**

**previous testimony and exhibits for the Sea Turtle Coastal Street Lighting Program?**

A. The project expenditure variance for the Sea Turtle Coastal Street Lighting Program is $600 or 100% lower than projected. This variance is due to no turtle compliance issues that needed to be rectified in 2013.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

COREY ZEIGLER

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

July 25, 2014

**Q. Please state your name and business address.**

A. My name is Corey Zeigler. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

**Q. Have you previously filed testimony before this Commission in Docket No. 140007-EI?**

A: Yes, I provided direct testimony on April 1, 2014.

**Q: Has your job description, education background and professional experience changed since that time?**

A: No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to explain material variances between 2014 estimated/actual cost projections and original 2014 cost projections for compliance costs associated with the FPSC-approved environmental programs under my responsibility. These programs include the Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Projects 1 & 1a), Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2) and Sea Turtle – Coastal Street Lighting Program (Project 9).

**Q. Please explain the variance between the estimated/actual project expenditures and original projections for the Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Projects 1 & 1a) for the period January 2014 to December 2014.**

A. O&M expenditures for the substation system programs are estimated to be $1 million or 55% higher than originally projected. This increase is primarily attributable to remediation work completed at Turner Plant substation January through May of this year, and ongoing remediation work at Central Florida substation. At the time of the 2014 Projection Filing, both of these sites were slated for institutional controls. However, DEF subsequently determined that contaminated soil could be removed at these substations. Duke Energy Florida (DEF) is currently excavating contaminated soil at Central Florida and expects to continue work throughout July and August. DEF has also shifted remediation activities at several distribution substations to this Fall when outages at these sites can occur without impacting demand requirements.

**Q. Please explain the variance between estimated/actual project expenditures and original projections for the Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2) for the period January 2014 to December 2014.**

A. O&M expenditures for the distribution system program are estimated to be $2,505 or 16% lower than originally projected. There are three remaining Transformer Replacement and Inspection Program (TRIP) sites. Two of these transformer sites are in groundwater monitoring, which DEF expects to continue into 2015. DEF is waiting for customer legal approval of an indemnification agreement to install a groundwater monitoring well at the third site which is expected later this year.

**Q: Please explain the variance between estimated/actual project expenditures and original projections for the Sea Turtle – Coastal Street Lighting Program (Project 9) for the period January 2014 to December 2014.**

A: O&M project expenditures for the Sea Turtle – Coastal Street Lighting Program are estimated to be $480 or 100% lower than originally projected due to a delay in the Don Cesar lighting project as well as no current lighting issues in Gulf County for nesting turtles.

Capital expenditures for the Sea Turtle – Coastal Street Lighting Program are estimated to be $2,100 or 100% lower than originally projected for the reasons cited above.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

COREY ZEIGLER

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 140007-EI

AUGUST 22, 2014

**Q. Please state your name and business address.**

A. My name is Corey Zeigler. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

**Q. Have you previously filed testimony before this Commission in Docket No. 140007-EI?**

A. Yes. I provided direct testimony on April 1, 2014 and July 25, 2014.

**Q. Has your job description, education background or professional experience changed since that time?**

A. No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide estimates of costs that will be incurred in the year 2015 for Duke Energy Florida's (DEF or Company)

Substation Environmental Investigation, Remediation and Pollution Prevention Program (Projects 1 & 1a), Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2), and Sea Turtle - Coastal Street Lighting Program (Project 9).

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

A. Yes. I am co-sponsoring the following portions of the schedule Exhibit No._ (TGF-5) to Thomas G. Foster's direct testimony:

- 42-5P page 1 of 21 - Substation Environmental Investigation, Remediation, and Pollution Prevention
- 42-5P page 2 of 21 - Distribution System Environmental Investigation, Remediation, and Pollution Prevention
- 42-5P page 10 of 21 - Sea Turtle - Coastal Street Lighting

**Q. What costs does DEF expect to incur in 2015 for the Substation System Investigation, Remediation and Pollution Prevention Program (Projects 1 & 1a)?**

A. DEF estimates O&M costs of approximately $1.5 million at 28 sites for the Substation System Investigation, Remediation and Pollution Prevention Program.

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

A. DEF works annually with the Florida Department of Environmental Protection (FDEP) to identify specific substation sites for remediation to ensure compliance with FDEP criteria. To ensure the level of expenditures is reasonable and prudent, DEF closely monitors remediation work and provides quarterly reports to the FDEP on remediation progress.

**Q. What costs does DEF expect to incur in 2015 for the Distribution System Investigation, Remediation and Pollution Prevention Program (Project 2)?**

A. DEF estimates O&M costs of approximately $16k to perform quarterly groundwater monitoring at 2 sites and remediation at 1 site for the Distribution System Investigation, Remediation and Pollution Prevention Program.

**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, DEF closely monitors remediation work and provides quarterly reports to the FDEP on progress made at sites.

**Q. What costs does DEF expect to incur in 2015 for the Sea Turtle – Coastal Street Lighting Program (Project 9)?**

A. DEF estimates capital and O&M expenses of approximately $3,600 and1,200, respectively, for the Sea Turtle – Coastal Street Lighting Program to ensure compliance with sea turtle ordinances in Franklin, Gulf, and Pinellas Counties and the City of Mexico Beach.

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

A. DEF cooperates with local governments and regulatory agencies to develop compliance plans that allow flexibility to make modifications necessary to achieve and maintain compliance. DEF ensures that evaluation of each streetlight requiring modification occurs so that the activities necessary to achieve and maintain compliance are performed in a reasonable and prudent manner. In addition, DEF evaluates emerging technologies and incorporates their use where reasonable and prudent.

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

A. Yes.

**BEFORE THE PUBLIC SERVICE COMMISSION**

**PREPARED DIRECT TESTIMONY**

**OF**

**PENELOPE A. RUSK**

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

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

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

**A.** I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility in the areas of fuel and capacity cost recovery. I have accumulated 17 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and FPSC-approved environmental projects.

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

**A.** The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2014 through December 2014 actual/estimated true-up amount to be refunded or recovered through the Environmental Cost Recovery Clause ("ECRC") during the period January 2015 through December 2015. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2014, based on six months of actual data and six months of estimated data. This information will be used in the determination of the environmental cost recovery factors for January 2015 through December 2015.

**Q.** Have you prepared an exhibit that shows the recoverable environmental costs for the actual/estimated period January 2014 through December 2014?

**A.** Yes. Exhibit No. _____ (PAR-1), containing nine documents, was prepared under my direction and supervision. It includes Forms 42-1E through 42-9E, which show the current period actual/estimated true-up amount to be used in calculating the cost recovery factors for January 2015 through December 2015.

**Q.** What has Tampa Electric calculated as the actual/estimated true-up for the current period to be applied to the January 2015 through December 2015 ECRC factors?

**A.** The actual/estimated true-up applicable for the current period, January 2014 through December 2014, is an over-recovery of $6,935,676. A detailed calculation supporting the calculation of the actual/estimated true-up is shown on Forms 42-1E through 42-9E of my exhibit.

**Q.** Is Tampa Electric including costs in the actual/estimated true-up filing for any new environmental projects that were not anticipated and included in its 2014 ECRC factors?

**A.** No, Tampa Electric is not including costs for any new environmental projects that were not anticipated or included in its 2014 ECRC factors.

**Q.** What depreciation rates were utilized for the capital projects contained in the 2014 actual/estimated true-up?

**A.** Tampa Electric utilized the depreciation rates approved in Order No. PSC-12-0175-PAA-EI, issued on April 3, 2012, in Docket No. 110131-EI.

**Q.** What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2014 through December 2014?

**A.** Tampa Electric relied upon the capital structure, components and cost rates approved by the Commission in Order No. PSC-12-0425-PAA-EU, issued on August 16, 2012 in Docket No. 120007-EI, to calculate the revenue requirement rate of return found on Form 42-9E.

**Q.** What is the nature of the adjustment shown on line 10 of Schedule 42-2E?

**A.** The total adjustment is a reduction in costs of $78,341, shown on line 10 of Schedule 42-2E. The adjustment was needed to correct charges related to the Clean Air Mercury Rule ("CAMR"), now known as Mercury Air Toxics Standards ("MATS"), and the Big Bend Unit 4 SCR project. Equipment needed to comply with CAMR/MATS was placed in service; however, the associated costs were not correctly charged to the project for the years 2011, 2012 and 2013. The adjustment corrects that error. An adjustment related to the Big Bend Unit 4 SCR project costs was also made. In the course of reviewing these costs, the company found that two work orders were inadvertently, incorrectly charged to the project. The error was corrected, and the Big Bend Unit 4 SCR project costs are reduced with this adjustment. The resulting overall reduction in costs from these two adjustments is $78,341.

**Q.** How did the actual/estimated project expenditures for the January 2014 through December 2014 period compare with the company's original projections?

**A.** As shown on Form 42-4E, total O&M costs are expected to be $701,132 less than the amount that was originally projected. The total capital expenditures itemized on Form 42-6E, are expected to be $2,342,016 less than originally projected. The material variances for O&M and capital investment projects are explained below.

**O&M Project Variances**

- **Big Bend Unit 3 Flue Gas Desulfurization Integration:** The Big Bend Unit 3 Flue Gas Desulfurization project variance is estimated to be $496,887 or 8.8 percent less than projected. A major outage that was scheduled for Big Bend Unit 4 in 2014 was rescheduled for 2015, resulting in a reduction of maintenance needed for this project in 2014.

- **$SO_2$ Emission Allowances:** The $SO_2$ Emission Allowances project variance is estimated to be $15,783 or 58.2 percent less than projected. The variance is due to less cogeneration purchases than projected and the application of a lower $SO_2$ emission allowance rate than originally projected.

- **Big Bend $NO_x$ Emissions Reduction:** The Big Bend $NO_x$ Emissions Reduction project variance is estimated to be $281,391 or 75 percent less than projected because the chemical consumption, maintenance and inspections costs originally projected for the Big Bend $NO_x$ Emissions Reduction project are now being recorded in unit-specific projects. These actual/estimated costs are now shown in the following projects: Big Bend Unit 4 SOFA, Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR.

- **Polk $NO_x$ Emissions Reduction:** The Polk $NO_x$ Emissions Reduction project variance is estimated to be $4,966 or 16.9 percent less than originally projected due to greater water usage by the saturator that is used to reduce $NO_x$ emissions than originally projected because Polk Power Station is expected to operate for a greater number of hours than originally projected.

- **Bayside SCR Consumables:** The Bayside SCR Consumables variance is estimated to be $20,057 or 13.4 percent less than originally projected due to a decrease in chemical consumption. The decrease in consumption is driven by the extension of the Bayside Unit 1 planned outage.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program variance is estimated to be $520,705 or 123.4 percent greater than what was originally projected due to three factors. There was an increase in consulting costs due to work extending 12 days past the original date. An additional groundwater pilot test is scheduled to begin in August. Finally, additional labor costs were incurred to remove railroad ties in the excavation area.

- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study variance is estimated to be $50,023 greater than originally projected. Implementation of this rule was delayed, as discussed in previous years' testimony in this docket. On May 19, 2014, the EPA issued a prepublication copy of the final rule, and now the consulting work can begin, to meet the requirements and schedule included in the May 19, 2014 rule.

- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is estimated to be $229,430 or 9.5 percent greater than originally projected due to actual/estimated consumption of ammonia being greater than originally projected. Greater ammonia consumption is expected because Big Bend Unit 1 is expected to operate for a greater number of hours than originally projected.

- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is estimated to be $343,724 or 11.7 percent less than originally projected due to actual consumption of ammonia being less than originally projected. Additionally, the cost per ton of consumable ammonia is expected to be less than originally projected, which contributed to the variance.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is estimated to be $289,697 or 25.4 percent less than originally projected. The actual/estimated consumption of ammonia is expected to be less than originally projected because Big Bend Unit 4 is expected to operate for fewer hours than originally projected, as the result of the extension of its planned maintenance outage. Additionally, the cost per ton of consumable ammonia is expected to be less than originally projected, which contributed to the variance.

- **Mercury Air Toxics Standards (“MATS”):** The MATS program variance is expected to be $103,445 or 47.3 percent less than originally projected because Tampa Electric used internal labor resources for stack testing. The original projection included costs for contract labor to complete the testing.

- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility program variance is expected to be $256,232 or 24.4 percent less than originally projected because the project will be entering commercial service later than originally projected. The Big Bend Gypsum Storage Facility’s original projected in-service date was June 2014; however, it is now scheduled to begin commercial service in October 2014.

**Capital Investment Project Variances**

- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance is estimated to be $132,353 or 7.1 percent less than projected due to a change in the in-service date of the precipitator upgrades. The new in-service date is expected to be November 2015, rather than December 2014. Cost recovery of ROI and depreciation are therefore delayed, resulting in lower expected project costs for 2014.

- **Mercury Air Toxics Standards:** The MATS program variance is estimated to be $372,289 or 33.9 percent less than originally projected due to two factors. First, some capital expenditures were projected to receive CWIP accounting treatment; however, the capital expenditures are receiving AFUDC treatment and will be included in the project costs when it begins commercial service. The second factor is that additional equipment that was originally projected to be purchased in 2014 is not needed at this time because the existing equipment has been sufficient to comply with current regulations.

- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility project variance is estimated to be $1,105,293 or 66.4 percent less than projected. The in-service date for the Big Bend Gypsum Storage Facility project was changed from the original projection of June 2014 to October 2014. Cost recovery of ROI and depreciation are therefore delayed, resulting in lower expected project costs for 2014.

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

**A.** Yes, it does.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 140007-EI**
**FILED: 08/22/2014**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**PREPARED DIRECT TESTIMONY**

**OF**

**PENELOPE A. RUSK**

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

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

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

**A.** I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility in the areas of fuel and capacity cost recovery. I have accumulated 17 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and FPSC-approved environmental projects

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

**A.** The purpose of my testimony is to present, for Commission review and approval, the calculation of the revenue requirements and the projected ECRC factors for the period of January 2015 through December 2015. The projected ECRC factors have been calculated based on the current allocation methodology. In support of the projected ECRC factors, my testimony identifies the capital and operating and maintenance (“O&M”) costs associated with environmental compliance activities for the year 2015.

**Q.** Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2015 through December 2015?

**A.** Yes. Exhibit No. ___ (PAR-2), containing eight documents, was prepared under my direction and supervision. Document Nos. 1 through 8 contain Forms 42-1P through 42-8P, which show the calculation and summary of O&M and capital expenditures that support the development of the environmental cost recovery factors for 2015.

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

**A.** Yes. The ECRC factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (PAR-2), Document No. 7, on Form 42-7P. These annualized factors will apply for the period January through December 2015.

**Q.** What has Tampa Electric calculated as the net true-up to be applied in the period January 2015 through December 2015?

**A.** The net true-up applicable for this period is an over-recovery of $8,892,748. This consists of the final true-up over-recovery of $1,957,072 for the period of January 2013 through December 2013 and an estimated true-up over-recovery of $6,935,676 for the current period of January 2014 through December 2014. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-9E of Exhibit No. ___ (PAR-1) filed with the Commission on July 25, 2014.

**Q.** Will Tampa Electric include any new environmental compliance projects for ECRC cost recovery for the period from January 2015 through December 2015?

**A.** No, Tampa Electric is not including any new environmental compliance projects for ECRC cost recovery during 2015.

**Q.** What are the existing capital projects included in the calculation of the ECRC factors for 2015?

**A.** Tampa Electric proposes to include for ECRC recovery the 25 previously approved capital projects and their projected costs in the calculation of the ECRC factors for 2015. These projects are:

1) Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) Big Bend Unit 4 Continuous Emissions Monitors

4) Big Bend Fuel Oil Tank 1 Upgrade
5) Big Bend Fuel Oil Tank 2 Upgrade
6) Big Bend Unit 1 Classifier Replacement
7) Big Bend Unit 2 Classifier Replacement
8) Big Bend Section 114 Mercury Testing Platform
9) Big Bend Units 1 and 2 FGD
10) Big Bend FGD Optimization and Utilization
11) Big Bend $NO_x$ Emissions Reduction
12) Big Bend Particulate Matter ("PM") Minimization and Monitoring
13) Polk $NO_x$ Emissions Reduction
14) Big Bend Unit 4 SOFA
15) Big Bend Unit 1 Pre-SCR
16) Big Bend Unit 2 Pre-SCR
17) Big Bend Unit 3 Pre-SCR
18) Big Bend Unit 1 SCR
19) Big Bend Unit 2 SCR
20) Big Bend Unit 3 SCR
21) Big Bend Unit 4 SCR
22) Big Bend FGD System Reliability
23) Mercury Air Toxics Standards ("MATS")
24) $SO_2$ Emission Allowances
25) Big Bend Gypsum Storage Facility

Some of these projects are described in more detail in the direct testimony of Tampa Electric Witness, Paul Carpinone.

**Q.** Have you prepared schedules showing the calculation of the recoverable capital project costs for 2015?

**A.** Yes. Form 42-3P contained in Exhibit No. ___ (PAR-2) summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 26, provides the calculations of the costs, which result in recoverable jurisdictional capital costs of $55,840,291.

**Q.** What are the existing O&M projects included in the calculation of the ECRC factors for 2015?

**A.** Tampa Electric proposes to include for ECRC recovery the 23 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2015. These projects are:

1) Big Bend Unit 3 FGD Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) $SO_2$ Emissions Allowances
4) Big Bend Units 1 and 2 FGD
5) Big Bend PM Minimization and Monitoring

6) Big Bend $NO_x$ Emissions Reduction
7) NPDES Annual Surveillance Fees
8) Gannon Thermal Discharge Study
9) Polk $NO_x$ Emissions Reduction
10) Bayside SCR Consumables
11) Big Bend Unit 4 SOFA
12) Big Bend Unit 1 Pre-SCR
13) Big Bend Unit 2 Pre-SCR
14) Big Bend Unit 3 Pre-SCR
15) Clean Water Act Section 316(b) Phase II Study
16) Arsenic Groundwater Standard Program
17) Big Bend Unit 1 SCR
18) Big Bend Unit 2 SCR
19) Big Bend Unit 3 SCR
20) Big Bend Unit 4 SCR
21) Mercury Air Toxics Standards
22) Greenhouse Gas Reduction Program
23) Big Bend Gypsum Storage Facility

Some of these projects are described in more detail in the direct testimony of Tampa Electric Witness, Paul Carpinone.

**Q.** Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2015?

**A.** Yes. Form 42-2P contained in Exhibit No. ___ (PAR-2) summarizes the recoverable jurisdictional O&M costs for these projects which total $28,566,214 for 2015.

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

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

**Q.** What are the total projected jurisdictional costs for environmental compliance in the year 2015?

**A.** The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $84,406,505.

**Q.** How were environmental cost recovery factors calculated?

**A.** The environmental cost recovery factors were calculated as shown on Schedules 42-6P and 42-7P. The demand allocation factors were calculated by determining the percentage each rate class contributes to the monthly system peaks and then adjusted for losses for each rate class. The energy allocation factors were determined by calculating the percentage that each rate class contributes to total MWH sales and then adjusted for losses for each rate class. This information was based on applying historical rate class load research to the 2015 projected forecast of system demand and energy. Form 42-7P presents the calculation of the proposed ECRC factors by rate class.

**Q.** What are the ECRC billing factors for the period of January through December 2015 which Tampa Electric is seeking approval?

**A.** The computation of the billing factors is shown in Exhibit No. ___ (PAR-2) Document No. 7, Form 42-7P. In summary, the January through December 2015 proposed ECRC billing factors are as follows:

| Rate Class | Factor by Voltage Level(¢/kWh) |
|---|---|
| RS Secondary | 0.408 |
| GS, TS Secondary | 0.407 |

| | |
|---|---|
| GSD, SBF | |
| Secondary | 0.405 |
| Primary | 0.401 |
| Transmission | 0.397 |
| IS | |
| Secondary | 0.397 |
| Primary | 0.393 |
| Transmission | 0.389 |
| LS1 | 0.401 |
| Average Factor | 0.406 |

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

**A.** The environmental cost recovery factors will be effective concurrent with the first billing cycle for January 2015.

**Q.** What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2015 through December 2015?

**A.** Tampa Electric relied upon the weighted average cost of capital methodology approved by the Commission in Order No. PSC-12-0425-PAA-EU, to calculate the revenue requirement rate of return found on Form 42-8P.

**Q.** Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2015 through December 2015 consistent with criteria established for ECRC recovery in Order No. PSC-94-0044-FOF-EI?

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

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

**Q.** Please summarize your testimony.

**A.** My testimony supports the approval of a final average environmental billing factor of 0.406 cents per kWh. This includes the projected capital and O&M revenue requirements of $84,406,505 associated with a total of 31 environmental projects and a true-up over-recovery provision of $8,892,748 that is primarily driven by the combination of O&M expenditures being greater than anticipated while ECRC revenue was less than expected. My testimony also explains that the projected environmental expenditures for 2015 are appropriate for recovery through the ECRC.

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

**A.** Yes, it does.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 140007-EI**
**FILED: 08/22/2014**

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**PREPARED DIRECT TESTIMONY**

**OF**

**PAUL CARPINONE**

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

**A.** My name is Paul L. Carpinone. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Environmental Health & Safety in the Environmental Health and Safety Department.

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

**A.** I received a Bachelor of Science degree in Water Resources Engineering Technology from the Pennsylvania State University in 1978. I have been a Registered Professional Engineer in the states of Florida and Pennsylvania since 1984. Prior to joining Tampa Electric, I worked for Seminole Electric Cooperative as a Civil Engineer in various positions and in environmental consulting. In February 1988, I joined Tampa Electric as a Principal Engineer, and I have primarily worked in the area of Environmental Health and Safety. In 2006, I became Director of Environmental Health and Safety. My responsibilities include the development and administration of the company’s environmental, health and safety policies and goals. I am also responsible for ensuring resources, procedures and programs meet or surpass compliance with applicable environmental, health and safety requirements, and that rules and policies are in place and functioning appropriately and consistently throughout the company.

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

**A.** The purpose of my testimony is to demonstrate that the activities for which Tampa Electric seeks cost recovery through the Environmental Cost Recovery Clause (“ECRC”) for the January 2015 through December 2015 projection period are activities necessary for the company to comply with various environmental requirements. Specifically, I will describe the ongoing activities that are associated with the Consent Final Judgment (“CFJ”) entered into with the Florida Department of Environmental Protection (“FDEP”) and the Consent Decree (“CD”) lodged with the U.S. Environmental Protection Agency (“EPA”) and the Department of Justice. I will also discuss other programs previously approved by the Commission for recovery through the ECRC.

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

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

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

**A.** The Orders require Tampa Electric to create a plan for optimizing the availability and removal efficiency of the flue gas desulfurization systems ("FGD" or "scrubbers"). The plans were submitted to the EPA in two phases, and were approved in July 2000, and February 2001, respectively.

Phase I required Tampa Electric to work scrubber outages around the clock and to utilize contract labor, when necessary, to speed the return of a malfunctioning scrubber to service. In addition, Phase I required Tampa

Electric to review all critical scrubber spare parts and increase the number and availability of spare parts to ensure a speedy return to service of a malfunctioning scrubber.

Phase II outlined capital projects Tampa Electric was to perform to upgrade each scrubber at Big Bend Station. It also addressed the use of environmental dispatching in the event of a scrubber outage. All of the $SO_2$ emission reduction projects have been completed.

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

**A.** The Orders require Tampa Electric to develop and implement a best operational practices ("BOP") study to minimize PM emissions from each electrostatic precipitator ("ESP") and complete and implement a best available control technology ("BACT") analysis of the ESPs at Big Bend Station. The Orders also require the company to demonstrate the operation of a PM continuous emission monitoring system ("CEM") on Big Bend Units 3 and 4 and demonstrate the operation of a second PM CEM on another Big Bend unit. The first PM CEM was installed in February 2002. The installation and certification of the second PM CEM was completed in August 2009. Over time, however, the first PM CEM did not perform satisfactorily and replacement was required. Installation and certification of the replacement was completed in December 2010.

**Q.** Please describe the Big Bend PM Minimization and Monitoring program activities and provide the estimated capital and O&M expenditures for the period of January 2015 through December 2015.

**A.** The Big Bend PM Minimization and Monitoring program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. In the Order, the Commission found that the program met the requirements for recovery through the ECRC. Tampa Electric had previously identified various projects to improve precipitator performance and reduce PM emissions as required by the Orders. For 2015, capital expenditures are anticipated to be $6,668,646 for BOP and BACT equipment while O&M expenses associated with existing and recently installed BOP and BACT equipment and continued implementation of the BOP procedures are expected to be $840,000.

**Q.** What do the Orders require for $NO_x$ reductions?

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

**Q.** Please describe the Big Bend $NO_x$ Emission Reduction program activities and provide the estimated capital and O&M expenses for the period of January 2015 through December 2015.

**A.** The Big Bend $NO_x$ Emission Reduction program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. In the Order, the Commission found that the program met the requirements for recovery through the ECRC. Tampa Electric does not anticipate any capital expenditures in 2015; however, the company will perform maintenance on the previously approved and installed $NO_x$ reduction equipment. This activity is expected to result in approximately $120,000 of O&M expenses during 2015.

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

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

In order to meet the $NO_x$ emission rates and timing requirements of the Orders, Tampa Electric engaged an experienced consulting firm, Sargent and Lundy, to assist with the performance of a comprehensive study designed to identify the long-range plans for the generating units at Big Bend Station. The results of the study clearly indicated that the option to remain coal-fired at Big Bend Station and install the necessary $NO_x$ reduction technologies was the most cost-effective alternative to satisfy the $NO_x$ emission reductions required by the

Orders. This decision was communicated to the EPA and FDEP in August 2004. Tampa Electric also apprised the Commission of this decision in its filing made in Docket No. 040750-EI in August 2004.

**Q.** Please describe the Big Bend Units 1 through 3 Pre-SCR and the Big Bend Units 1 through 4 SCR projects and provide estimated capital and O&M expenditures for the period of January 2015 through December 2015.

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

2010, September 2009, July 2008 and May 2007, respectively.

For the period of January 2015 through December 2015, there are not any capital expenditures anticipated for the Big Bend Units 1 through 3 Pre-SCR projects. The O&M expenditures for Big Bend Pre-SCR projects are projected to be $138,000 for Big Bend Unit 1 Pre-SCR, $48,000 for Big Bend Unit 2 Pre-SCR and $48,000 for Big Bend Unit 3 Pre-SCR for equipment maintenance. Additionally, there are not any anticipated capital expenditures for Big Bend Units 1, 2, and 4 SCRs. However, the capital expenditures for the Big Bend Unit 3 SCR are projected to be $2,000,000 for a catalyst replacement. Additionally, the 2015 SCR O&M expenses are projected to be $2,164,529 for Big Bend Unit 1 SCR, $2,499,255 for Big Bend Unit 2 SCR, $2,023,711 for Big Bend Unit 3 SCR and $1,111,949 for Big Bend Unit 4 SCR. These expenses are primarily associated with ammonia purchases.

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

**A.** The programs previously approved by the Commission that I will discuss include the following projects:

1) Big Bend Unit 3 FGD Integration
2) Big Bend Units 1 and 2 FGD
3) Gannon Thermal Discharge Study
4) Bayside SCR Consumables
5) Clean Water Act Section 316(b) Phase II Study
6) Big Bend FGD System Reliability
7) Arsenic Groundwater Standard
8) Mercury and Air Toxics Standards ("MATS")
9) Greenhouse Gas ("GHG") Reduction Program
10) Big Bend Gypsum Storage Facility

**Q.** Please describe the Big Bend Unit 3 FGD Integration and the Big Bend Units 1 and 2 FGD activities and provide the estimated capital and O&M expenditures for the period of January 2015 through December 2015.

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

Air Act Amendments ("CAAA") of 1990.

There are not any anticipated capital expenditures during January 2015 through December 2015 for the Big Bend Unit 3 FGD Integration project; however, O&M expenses are projected to be $6,245,680 for consumables, primarily anhydrous ammonia, and ongoing maintenance. There are not any anticipated capital expenditures for the Big Bend FGD Units 1 and 2 project during January 2015 through December 2015. O&M expenses are projected to be $10,189,162 for consumables, primarily anhydrous ammonia, and ongoing maintenance.

**Q.** Please describe the Gannon Thermal Discharge Study program activities and provide the estimated O&M expenditures for the period of January 2015 through December 2015.

**A.** The Gannon Thermal Discharge Study program was approved by the Commission in Docket No. 010593-EI, Order No. PSC-01-1847-PAA-EI, issued September 14, 2001. In that Order, the Commission found that the program met the requirements for recovery through the ECRC. For the period of January 2015 through December 2015, there are not any projected O&M expenditures for this program. In the intent to issue the permit renewal, dated August 9, 2013, FDEP indicated that the proposed NPDES permit authorizes a thermal variance under 316(a) for the permit period. It is anticipated that no additional study will be required.

**Q.** Please describe the Bayside SCR Consumables program activities and provide the estimated O&M expenditures for the period of January 2015 through December 2015.

**A.** The Bayside SCR Consumables program was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. For the period of January 2015 through December 2015, Tampa Electric projects O&M expenses associated with the consumable goods (primarily anhydrous ammonia) to be approximately $145,000 for the period.

**Q.** Please describe the Clean Water Act Section 316(b) Phase II Study program activities and provide the estimated O&M expenditures for the period of January 2015 through December 2015.

**A.** The Clean Water Act Section 316(b) Phase II Study program was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005. On March 20, 2007 the EPA announced that the rule adopted pursuant to Section 316(b) be considered suspended. The final rule was suspended on July 9, 2007. On April 20, 2012, the EPA published a proposed rule for existing steam electric generators, with the final rule expected in July 2012. However, in July 2012, the final rule was postponed again, until June 2013. In June 2013, the final rule was postponed until November 4, 2013. A pre-publication version of the final rule was made available in May 2014, and the final rule was published on August 15, 2014. Tampa Electric does not anticipate any capital expenditures related to these activities for 2015. However, Tampa Electric projects O&M expenditures to be $960,000 for the period January 2015 through December 2015 for engineering studies.

**Q.** Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital expenses for the period of January 2015 through December 2015.

**A.** Tampa Electric’s Big Bend FGD System Reliability program was approved by the Commission in Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006. The Commission granted cost recovery approval for prudent costs associated with this project. The Big Bend FGD

System Reliability project has been running concurrently with the installation of SCR systems on the generating units. For the period of January 2015 through December 2015, there are not any anticipated capital expenditures for this project.

**Q.** Please describe the Arsenic Groundwater Standard program activities and provide the estimated O&M expenditures for the period of January 2015 through December 2015.

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

For the period of January 2015 through December 2015, Tampa Electric projects O&M expenses associated with the sampling activities to be approximately $300,000.

**Q.** Please describe the MATS program activities and provide the estimated capital and O&M expenditures for the period of January 2015 through December 2015.

**A.** The MATS program was approved by the Commission in Docket No. 120302-EI, Order No. PSC-13-0191-PAA-EI, issued May 6, 2013. In that Order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric cost recovery approval for prudently incurred costs. Additionally, the Commission granted the subsumption of the previously approved CAMR program into the MATS program.

On February 8, 2008, the Washington D.C. Circuit Court vacated EPA's rule removing power plants from the Clean Air Act list of regulated sources of hazardous air pollutants under section 112. At the same time, the Court vacated the Clean Air Mercury Rule. On May 3, 2011, the EPA published a new proposed rule for mercury and other hazardous air pollutants according to the National Emissions Standards for Hazardous Air Pollutants section of the Clean Air Act. The proposed rule calls for continued mercury monitoring requirements comparable to CAMR and additional monitoring and testing of other pollutants by 2014. On February 16, 2012, the EPA published the final rule for MATS. The rule revised the mercury limits and provided more flexible monitoring and recordkeeping requirements. Additionally, monitoring of acid gases and particulate matter will be required. Existing sources will have through February 16, 2015 to comply with the rule. Tampa Electric must conduct extensive emissions testing and engineering studies at Big Bend Station and Polk Power Station to determine what actions are required to meet the proposed standards.

For 2015, the projected capital expenditures are $160,000 for replacement of required equipment for mercury monitoring and upgrades to the FGD systems to meet the emission standards required by the rule. The O&M expenditures are projected to be $230,000 for testing requirements and maintenance of equipment.

**Q.** What is the impact of the remand of the CAIR and vacatur of the CAMR on Tampa Electric's ECRC projects?

**A.** On July 6, 2010, the EPA proposed a new rule, the Clean Air Transport Rule to replace CAIR. On July 6, 2011, the EPA issued the final CAIR replacement rule, now called the Cross State Air Pollution Rule ("CSAPR"). CSAPR is focused on reducing $SO_2$ and $NO_X$ in 27 eastern states that contribute to ozone and/or fine particle pollution in other states. In the final rule, Florida is subject to the ozone season control program (May through September). In December 2011, the final rule was stayed by the United States Court of Appeals District of Columbia Circuit. The stay on the finalized CSAPR and the remand of CAIR have minimal impact on Tampa Electric's ECRC projects associated with $NO_x$ and $SO_2$ abatement. These projects were initiated as a result of the CD signed between the EPA and Tampa Electric; therefore, the company anticipates continuing its efforts to complete and maintain the projects. The completed ECRC projects support compliance with CSAPR.

The vacatur of CAMR occurred after Tampa Electric had begun the procurement of equipment necessary to meet the intent of the original rule; however, the company was able to stop a significant portion of the total equipment purchase. Subsequent to the vacatur, the company has continued utilizing the resources already secured to establish a baseline of mercury emissions.

On May 3, 2011, the EPA proposed rules under National Emission Standards for Hazardous Air Pollutants pursuant to a court order referred to as the Utility Maximum Achievable Control Technology ("U MACT"). The proposed rules are to replace CAMR and are expected to reduce not only mercury but acid gas, organics and certain non-mercury metals emissions. The final U MACT rules were released in February 2012 and require implementation by May 2015. The company continues to utilize the resources already secured to establish a baseline on mercury and other emissions subject to the proposed rule and expects to purchase other equipment that will be required to comply with the rules.

**Q.** Please describe the GHG Reduction Program activities and provide the estimated capital and O&M expenditures for the period of January 2015 through December 2015.

**A.** Tampa Electric's GHG Reduction Program approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PPA-EI, issued March 22, 2010 is a result of the EPA's Mandatory Reporting Rule requiring annual reporting of greenhouse gas emissions. Tampa Electric was required to report greenhouse gas emissions to the EPA for the first time in 2011. Reporting for the EPA's Greenhouse Gas Mandatory Reporting Rule will continue in 2015. For 2015, this activity is not anticipated to require any capital expenditures; however, it is projected to result in approximately $90,000 of O&M expenditures.

**Q.** Please describe the Big Bend Gypsum Storage Facility activities and provide the estimated capital and O&M expenditures for the period of January 2015 through December 2015.

**A.** The Big Bend Gypsum Storage Facility program was approved by the Commission in Docket No. 110262-EI, Order No. 12-0493-PAA-EI, issued September 26, 2012. In that Order, the Commission found that the program meets the requirements for recovery through ECRC. The completion of the project and in-service date is projected to be October 2014. The total installed capital cost at that time is estimated to be approximately $22,000,000 and the O&M for 2015 is projected to be $1,284,000.

**Q.** Please summarize your testimony.

**A.** Tampa Electric’s settlement agreements with FDEP and EPA require significant reductions in emissions from Tampa Electric’s Big Bend and Gannon Stations. The Orders established definite requirements and time frames in which air quality improvements must be made and result in reasonable and fair outcomes for Tampa Electric, its community and customers, and the environmental agencies. My testimony identified projects that are legally required by these Orders. I described the progress Tampa Electric has made to achieve the more stringent environmental standards. I identified estimated costs, by project, which the company expects to incur in 2015. Additionally, my testimony identified other projects that are required for Tampa Electric to meet environmental requirements, and I provided the associated 2015 activities and projected expenditures.

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

**A.** Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 140007-EI
April 1, 2014

Q. Please state your name and business address.

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

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

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

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

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

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

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

Q. Mr. Vick, what is the purpose of your testimony?
A. The purpose of my testimony is to support Gulf Power Company's Environmental Cost Recovery Clause (ECRC) final true-up for the period January through December 2013.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2013 through December 2013 with the approved estimated true-up amounts.
A. As reflected in Mr. Dodd's Schedule 6A, the actual recoverable capital costs were $122,354,257 as compared to $122,740,511 included in the Estimated True-up filing. This resulted in a net variance of ($386,254) below the estimated true-up. The variance was primarily due to the Air Quality

Compliance Program (Line item 1.26) previously known as the CAIR/CAMR/CAVR Compliance Program.

Q Please explain the capital variance of ($391,188) or (0.4%) in the Air Quality Compliance Program (Line item 1.26)

A. This variance is primarily due to Mississippi property tax expenses related to Plant Daniel scrubber projects being lower than projected in the Estimated True-up filing. The Plant Daniel scrubber projects are currently under construction and scheduled to be placed in-service in December 2015.

Q. How do the actual O&M expenses for the period January 2013 to December 2013 compare to the amounts included in the Estimated True-up filing?

A. Mr. Dodd's Schedule 4A reflects that Gulf's recoverable environmental O&M expenses for the current period were $25,183,923, as compared to the estimated true-up of $23,784,222. This resulted in a variance of $1,399,701 or 5.9% above the estimated true-up. I will address nine O&M projects and/or programs that contribute to this variance: Groundwater Contamination Investigation, State NPDES Administration, General Solid & Hazardous Waste, Above Ground Storage Tanks, Sodium Injection program, FDEP NOx Reduction Agreement, Air Quality Compliance Program, Crist Water Conservation, and $SO_2$ Allowances.

Q. Please explain the variance of $1,129,516 or 53.5% in (Line Item 1.7), Groundwater Contamination Investigation.

A. This line item includes expenses related to substation investigation and remediation activities. This variance is primarily due to an increase in cost of the Highland City Substation excavation of contaminated soils project. The cost increase is related to increasing the depth of excavation and the need to accelerate completion of a portion of the excavation to allow substation construction activities to begin in these areas. As a result of transmission construction timing, Gulf needed to complete approximately 50% of the excavation work in 2013 to enable transmission construction activities to be initiated on time.

Q. Please explain the variance of ($26,725) or (74.1%) in (Line item 1.8), State NPDES Administration.

A. This line item is for the State NPDES Administration fees that are required by the State of Florida's National Pollutant Discharge Elimination System (NPDES) program administration. Annual and five year permit renewal fees are required for the NPDES industrial wastewater permits at Plants Crist, Smith and Scholz. The variance in this line item is simply a timing difference due to paying the annual fees in January 2014 instead of December of 2013 as initially projected.

Q. Please explain the variance of $235,219 or 42.9% in (Line item 1.11), General Solid & Hazardous Waste.

A. This line item includes expenses for proper identification, handling, storage, transportation and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. This variance is primarily due to costs associated with transformer oil spills and associated disposal costs for Gulf's power delivery operations that were not projected. The exact number and cost of these events cannot be predicted in advance.

Q. Please explain the variance of ($37,437) or (18.5%) in (Line item 1.12), Above Ground Storage Tanks.

A. This variance is primarily due to delaying an internal inspection of one of the fuel tanks at Plant Smith to first quarter of 2014. Additional work was required on one Plant Smith Combustion Turbine (CT) fuel tank which delayed work on the second CT tank. The Plant Crist above ground storage maintenance expenses were also less than originally anticipated.

Q. Please explain the variance of ($16,288) or (37.4%) in (Line item 1.16), Sodium Injection program.

A. This line item includes the O&M expenses associated with the sodium injection systems at Plant Smith and Plant Crist. Sodium carbonate is added to the Plant Crist and Plant Smith coal supply to enhance precipitator efficiencies when burning certain low sulfur coals. This variance is primarily due to less sodium carbonate being required for Plant Crist Units 4 and 5. The quantity of sodium carbonate is directly related to how much Plant Crist Units 4 and 5 are dispatched to meet system loads and during this period these units have been dispatched less than originally projected.

Q Please explain the variance of ($340,493) or (17.8%) in FDEP NOx Reduction Agreement (Line Item 1.19).

A. The FDEP NOx Reduction Agreement includes O&M costs associated with the Plant Crist Unit 7 SCR and the Plant Crist Units 4 through 6 SNCR projects that were included as part of the 2002 agreement with FDEP. More specifically, this line item includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the agreement. This variance is primarily due to less ammonia and urea being needed due to burning less coal at Plant Crist than originally projected. Also, the cost per ton for these chemicals was less than originally projected.

Q. Please explain the O&M variance $682,599 or 4.5% in the Air Quality Compliance Program, (Line Item 1.20).

A. The Air Quality Compliance Program line item primarily includes O&M expenses associated with the Plant Crist Units 4 through 7 scrubber and the Plant Smith Units 1 and 2 SNCRs. More specifically, this line item included the cost of urea, limestone, and general operation and maintenance activities included in Gulf's Compliance Program. This variance is primarily due to: 1) taxes and other related expenses for limestone purchases being inadvertently omitted from the 2013 projections; 2) transportation and other expenses associated with gypsum sales being greater than anticipated; and 3) scrubber maintenance and repair activities being greater than originally projected.

Q. Please explain the O&M variance of ($81,060) or (33.3%) in the Crist Water Conservation Program (Line Item 1.22).

A. The Crist Water Conservation line item includes general O&M expenses associated with the Plant Crist reclaimed water system. This variance is primarily due to maintenance costs being less than originally projected due to a piece of equipment being covered under warranty which resulted in no charge to the company instead of it being a company expense as projected.

Q. Please explain the variance of ($158,133) or (28.9 %) in $SO_2$ Allowances (Line Item 1.26).

A. This variance is the result of Gulf surrendering fewer $SO_2$ allowances than originally projected due to lower utilization of the coal units.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
James O. Vick
Docket No. 140007-EI
Date of Filing: July 25, 2014

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

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

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

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

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

Q. Mr. Vick, what is the purpose of your testimony?
A. The purpose of my testimony is to support Gulf Power Company's Environmental Cost Recovery Clause (ECRC) estimated true-up for the period January through December 2014. This true-up is based on six months of actual data and six months of estimated data.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the estimated true-up calculation for the period January 2014 through December 2014 with the approved projected amounts.
A. As reflected in Mr. Boyett's Schedule 6E, the recoverable capital costs approved in the original projection total $118,799,522 as compared to the estimated true-up amount of $118,625,423. This results in a variance of ($174,100) or (0.1%).

Q. Are there any factors that impact multiple capital projects?

A. Yes. The recoverable capital costs included in the estimated true-up calculation are approximately $174,000 less than the capital costs included in the 2014 Projection filing. The primary driver is the difference between the weighted average cost of capital (WACC) used in the 2014 Projection filing versus the WACC applied to the July through December 2014 period in this 2014 Estimated/Actual True-up filing. In accordance with Commission Order No. PSC-12-0425-PAA-EU, the 2014 Projection filing used the WACC presented in Gulf's May 2013 Earnings Surveillance Report for January through December 2014. In this 2014 Estimated/Actual True-Up filing, the projected July through December 2014 period uses the WACC presented in Gulf's May 2014 Earnings Surveillance Report. After taking this item into consideration, there is a positive variance of approximately $15,591 that is largely attributed to three capital projects: 1) Substation Contamination Remediation $53,279; 2) Crist FDEP Agreement for Ozone Attainment $62,046; and 3) Air Quality Compliance Program ($115,742). The variances attributed to these programs will be discussed below.

Q. Please explain the capital variance of $53,279 or 29.8% reflected in Substation Contamination Remediation (Line item 1.6).

A. The Substation Contamination Remediation variance is due to adding additional groundwater recovery well pumps and controls to the existing Ft. Walton substation treatment system. The offsite system will help further contain and treat the impacted groundwater plume. Gulf's use of this system was approved by the Florida Department of Environmental Protection (FDEP) on January 31, 2014.

Q. Please explain the capital variance of $62,046 or 0.5% reflected in the Crist FDEP Agreement for Ozone Attainment Program (Line Item 1.19).

A. This variance is primarily due to increased catalyst storage expenses and timing of the Plant Crist Unit 7 SCR catalyst replacement expenditures. Progress payments for the replacement catalyst that were originally projected to be made in September through December 2014 were made in the first quarter of 2014.

Q. Please explain the capital variance of ($115,742) or (0.1%) reflected in the Air Quality Compliance Program (Line Item 1.26).

A. The line item variance is primarily due to a decrease in the projected 2014 expenditures for the Plant Daniel mercury monitoring, bromine injection, and activated carbon injection projects and the Plant Crist scrubber raw water pump project. The Plant Daniel mercury monitors were inadvertently budgeted twice in the original ECRC projection filing. In addition, equipment purchases and installation expenditures for both Plant Daniel projects were delayed three months pending necessary regulatory approvals. The Plant Crist Scrubber raw water pump project has been removed from the 2104 budget projection because the plant was able to rebuild the existing pumps. These reductions were partially offset by an increase in the projected 2014 expenditures for the Plant Crist scrubber controls project and the Plant Crist gypsum storage cell design work.

Q. How do the estimated/actual 2014 O&M expenses compare to the original 2014 projections?

A. Mr. Boyett's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated at $30,247,005 as compared to $27,988,313. The Estimated/Actual expenses are $2,258,692 or 8.1% above the amount projected in the 2014 Projection Filing. I will address seven O&M projects and programs that contribute to this variance: General Water Quality, Groundwater Contamination Investigation, General Solid & Hazardous Waste, FDEP NOx Reduction Agreement, Air Quality Compliance Program, Crist Water Conservation, and Annual NOx Allowances.

Q. Please explain the O&M variance of ($303,124) or (9.3%) in (Line item 1.6), the General Water Quality program.

A. The General Water Quality variance is primarily due to postponing the 316(b) biological evaluations due to a delay in issuance of the final EPA 316(b) intake structure regulation. When Gulf's 2014 budget projection was prepared Gulf expected the final 316(b) regulation to be issued in November of 2013. The rule was not signed by the EPA administrator until May 19, 2014. The 316(b) rule will become effective 60 days after publication in the Federal Register. To date the rule has not been published in the Federal Register. Gulf's 316(b) biological evaluations are currently anticipated to be conducted between late 2014 through 2019.

Q. Please explain the O&M variance of $1,712,018 or 64.7% in (Line item 1.7) Groundwater Contamination Investigation.

A. This line item includes expenses related to substation investigation and remediation activities. This variance is primarily due to an increase in cost of the Highland City and Holmes Creek Substation excavation of contaminated soils projects. The Highland City cost increase is related to increasing the scope of excavation due to a lower groundwater table elevation than previously expected. The lower natural groundwater table allowed more impacted soils to be removed. The Holmes Creek substation cost increased due a change in scope to remove more soil than previously projected.

Q. Please explain the O&M variance of $69,407 or 11.9% in FDEP General Solid & Hazardous Waste (Line Item 1.11).

A. This variance is primarily due to two issues, the unexpected Plant Scholz solid waste disposal costs and the costs associated with transformer oil spills for Gulf's power delivery operations. Neither of which were projected.

Q. Please explain the O&M variance of ($216,878) or (7.6%) in FDEP NOx Reduction Agreement (Line Item 1.19).

A. The FDEP NOx Reduction Agreement includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses for activities undertaken in connection with the Plant Crist FDEP Agreement related to Ozone Attainment. This variance is primarily due to a decrease in chemical expenses as a result of lower ammonia prices (cost per unit) for the Plant Crist Unit 7 SCR since the time Gulf prepared the 2014 ECRC Projection filing.

Q. Please explain the O&M variance $1,085,273 or 6.8% in the Air Quality Compliance Program, (Line Item 1.20).

A. The Air Quality Compliance Program currently includes O&M expenses associated with the Plant Crist scrubber, the Crist Unit 6 SCR and the Smith Units 1 and 2 SNCRs. More specifically, this line item includes the cost of urea, ammonia, limestone, and general operation and maintenance activities included in Gulf's Air Quality Compliance Program. The line item variance is primarily due to an increase in the projected Plant Crist scrubber limestone expenses due to higher utilization of Gulf's coal-fired units than expected and the inadvertent omission of taxes related to the purchase of limestone in the projection filing.

Q. Please explain the O&M variance of ($78,854) or (26.5%) in the Crist Water Conservation Program (Line Item 1.22).

A. The Plant Crist Water Conservation line item includes general O&M expenses associated with the Plant Crist reclaimed water system. This variance is primarily due to lower chemical and maintenance costs as a result of rebuilding the cooling tower chemical house. During the rebuilding of the chemical house, chemical injection pumps and instruments were out of service which reduced the chemical usage.

Q. Please explain the variance of $47,925 or 26.0 % in Annual NOx Allowances (Line Item 1.24).

A. Plants Daniel and Smith ran more than projected and thus more allowances were utilized in the months of January through March than projected.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 140007-EI
Date of Filing: August 22, 2014

Q. Please state your name and business address.

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

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

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

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

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

Q. What are your responsibilities with Gulf Power Company?

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

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

A. Yes.

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

A. The purpose of my testimony is to support Gulf Power Company's projection of environmental compliance costs recoverable through the Environmental Cost Recovery Clause (ECRC) for the period from January 2015 through December 2015.

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

A. The environmental capital projects for which Gulf seeks recovery through the ECRC are described in Schedules 3P, 4P, and 5P of Witness Boyett's Exhibit CSB-2. I am supporting the expenditures, clearings, retirements, salvage and cost of removal currently projected for each of these projects. Mr. Boyett compiled these schedules and has calculated the associated revenue requirements for Gulf's requested recovery. Of the projects shown on Mr. Boyett's schedules, there are five programs that were previously approved by the Commission with activities that have projected capital expenditures during 2015. These programs include: Crist 5, 6, & 7 Precipitator Upgrades, Crist 6 & 7 Low NOx burners, Smith Water Conservation, Crist FDEP Agreement for Ozone Attainment, and the Air Quality Compliance program.

Q. Are there any projects that impact multiple capital programs?

A. Yes. During 2015, Plant Crist plans to upgrade several digital control systems for existing ECRC equipment including the Unit 6 and Unit 7 Selective Catalytic Reduction (SCR) systems, the Unit 6 and Unit 7 Low NOx burners, the Unit 6 precipitator, and the Units 4 through 7 scrubber. The upgrades will include both hardware and software upgrades. The digital control systems will be replaced with equipment that runs on an updated operating system. The projected 2015 expenditures for the ECRC digital controls projects is $1,061,041.

Q. Mr. Vick, please provide an update on the Smith Water Conservation project (Line item 1.17).

A. As discussed in previous filings, Gulf determined that it is feasible to inject reclaimed water into the Plant Smith deep injection well system. Gulf is currently completing the second and third of the five injection wells that were permitted. During the latter part of 2014 and into 2015, Gulf anticipates conducting further injection testing of the existing wells as well as finalizing the design and installation of the initial phase of the pump system. This testing will determine whether additional wells are necessary. Expenditures associated with these activities reflected in the 2015 projection filing are $4.3 million.

Q. Mr. Vick, please describe the projects included in the 2015 projection for (Line Item 1.19) the Crist FDEP Agreement for Ozone Attainment.

A. Gulf plans to replace the Plant Crist Unit 7 SCR flue gas sampling fans and ammonia unloading piping during 2015. The flue gas sampling fans are necessary to measure the NOx concentration entering and exiting the SCR in order to control the ammonia injection rate. The existing fans and ammonia unloading area piping are approximately ten years old and are approaching the end of their useful life. The projected 2015 expenditures for this line item are $975,300; which includes $82,800 for the previously discussed Plant Crist Unit 7 SCR digital controls upgrade.

Q. Mr. Vick, please describe the projected 2015 capital expenditures for the Air Quality Compliance program (Line Item 1.26).

A. The projected 2015 expenditures for this line item include new air emission controls for Plant Daniel and monitoring equipment needed for Plant Daniel and Plant Crist to comply with the MATS (Mercury and Air Toxics Standards) regulation. Also, projected for this line item are capital retrofit projects for the Plant Crist scrubber and the Plant Crist Unit 6 SCR.

Q. Please discuss the controls and monitoring equipment needed to comply with the MATS regulations.

A. As discussed in Gulf's April 2014 Compliance Program update, Gulf Power has determined that bromine injection upstream of the precipitator with activated carbon injection (ACI) will be required to comply with the MATS mercury standards at Plant Daniel. Engineering, procurement, and construction of the Plant Daniel bromine and ACI systems began in January 2014 and is scheduled to last for approximately two years. Both injection systems will be placed in service with the scrubbers during fourth quarter of 2015. The projected 2015 expenditures for Gulf's ownership portion of the Plant Daniel ACI and bromine injection projects are approximately $6.2 million. The ACI and bromine injection projects were approved for ECRC cost recovery in FPSC Order No. PSC-13-0506-PAA-EI in Docket No. 130092-EI.

Gulf Power will begin installing MATS monitoring systems at Plant Daniel and Plant Crist in 2014 in order to comply with the MATS rule. Mercury monitors were included in Gulf's original Compliance Plan that was filed on March 29, 2007. The Plant Daniel and Plant Crist mercury monitors were two of the 10 specific components of Gulf's program that were agreed to as part of a stipulation approved on August 14, 2007. The stipulation is included in Order No. PSC-07-0721-S-EI. The 2015 projected expenditures for the Plant Crist MATS monitoring systems are $626,000. The Plant Crist MATS monitoring system will monitor mercury and particulate emissions.

The Plant Daniel mercury monitoring costs are included in the cost projection for the Plant Daniel scrubbers.

Q. Please discuss the capital retrofit projects planned for the Plant Crist Unit 6 SCR and the Plant Crist scrubber.

A. Gulf plans to add an additional catalyst layer to the Plant Crist Unit 6 SCR during the spring 2015 outage. The projected 2015 expenditures for the new catalyst are $682,926. The Plant Crist Unit 6 SCR and scrubber digital controls will be upgraded in 2015, as previously discussed. The 2015 projection includes expenditures totaling $170,289 for the Crist Unit 6 SCR controls upgrade and $241,946 for the scrubber controls upgrade that was initiated during 2014.

Q. Mr. Vick, please provide an update on the status of the Plant Daniel scrubber projects?

A. The Plant Daniel scrubber projects are currently scheduled for completion in December 2015. The scrubber stack concrete work has been completed, vertical stack liners are complete for both units 1 and 2, and the scrubber vessels are approximately 50% complete. The station service transformers and power supplies were recently installed and tested. The scrubbers when used in conjunction with the bromine and activated carbon injection systems will allow Plant Daniel to comply with the MATS standards as well as the CAIR/CSAPR and the CAVR. The 2015 capital expenditures for Gulf's ownership portion of the scrubber are projected to be $57.2 million.

Q. Mr. Vick, are you including the purchase of allowances in your 2015 projection filing?

A. No, we are not currently projecting the need to purchase additional allowances during 2015.

Q. How do the projected Environmental Operation and Maintenance (O&M) activities listed on Schedule 2P of Mr. Boyett's Exhibit CSB-2 compare to the O&M activities approved for cost recovery in past ECRC proceedings?

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

Q. Please describe the O&M activities included in the air quality category for 2015.

A. There are five O&M activities included in the air quality category that have projected expenses in 2015. On Schedule 2P, Air Emission Fees (Line Item 1.2), represents the expenses projected for the annual fees required by the Clean Air Act Amendments (CAAA) of 1990 that are payable to the FDEP and Mississippi Department of Environmental Quality. The expenses projected for the 2015 recovery period total $505,156.

Included in the air quality category, Title V (Line Item 1.3) represents projected ongoing expenses associated with implementation of the Title V permits. The total 2015 estimated expenses for the Title V Program are $142,158.

On Schedule 2P, Asbestos Fees (Line Item 1.4) consists of the fees required to be paid to the FDEP for asbestos abatement projects. The projected expenses for this line item are $1,500. Emission Monitoring (Line Item 1.5) on Schedule 2P reflects an ongoing O&M expense associated with the Continuous Emission Monitoring equipment as required by the CAAA. These expenses are incurred in response to EPA's requirements that the Company perform Quality Assurance/Quality Control (QA/QC) testing for the CEMS, including Relative Accuracy Test Audits (RATAs) and Linearity Tests. The expenses expected to be incurred during the 2015 recovery period for these activities total $807,348.

The FDEP NOx Reduction Agreement (Line Item 1.19) includes O&M costs associated with the Plant Crist Unit 7 SCR and the Plant Crist Units 4 and 5 Selective Non-Catalytic Reduction (SNCR) projects that were included as part of the 2002 agreement with FDEP. This line item includes the cost of anhydrous ammonia, urea, air monitoring, and general O&M expenses related to activities undertaken in connection with the agreement. Gulf was granted approval for recovery of the costs incurred to complete these activities in FPSC Order No. PSC-02-1396-PAA-EI in Docket No. 020943-EI. The projected expenses for the 2015 recovery period total $2.0 million.

Q. What O&M activities are included in the water quality category?

A. General Water Quality (Line Item 1.6), identified in Schedule 2P, includes costs associated with Soil Contamination Studies, NPDES permit compliance, Dechlorination, Groundwater Monitoring, Surface Water

Studies, the Cooling Water Intake Program, the Impaired Waters Rule, the Impoundment Integrity Program, and Stormwater Maintenance. The expenses expected to be incurred during the projection period for this line item totals $2.1 million. The projected cost includes $1.0 million for the 316(b) cooling water intake studies at Plant Crist and Plant Smith.

Q. What other O&M activities are included in the water quality category?

A. Groundwater Contamination Investigation (Line Item 1.7) was previously approved for environmental cost recovery in Docket No. 930613-EI. This line item includes expenses related to substation investigation and remediation activities. Gulf has projected $4.2 million of incremental expenses for this line item during the 2015 recovery period.

Line Item 1.8, State National Pollutant Discharge Elimination System (NPDES) Administration, was previously approved for recovery in the ECRC and reflects expenses associated with NPDES annual fees and permit renewal fees for Gulf's three generating facilities in Florida. These expenses are expected to be $49,500 during the projected recovery period.

Finally, Line Item 1.9, Lead and Copper Rule, was also previously approved for ECRC recovery and reflects sampling, analytical, and chemical costs related to the lead and copper drinking water quality standards. These expenses are expected to total $16,476 during the 2015 projection period.

Q. What activities are included in the environmental affairs administration category?

A. Only one O&M activity is included in this category on Schedule 2P (Line Item 1.10) of Mr. Boyett's Exhibit CSB-2. This line item refers to the Company's Environmental Audit/Assessment function. This program is an on-going compliance activity previously approved for ECRC recovery. Expenses totaling $9,000 are expected during the 2015 recovery period.

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

A. The General Solid and Hazardous Waste activity (Line Item 1.11) involves the proper identification, handling, storage, transportation, and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. This program is a previously approved program that is projected to incur incremental expenses totaling $707,522 in 2015.

Q. Are there any other O&M activities that have been approved for recovery that have projected expenses?

A. There are five other O&M activities that have been approved in past proceedings which have projected expenses during 2015. They are the Above Ground Storage Tanks program, the Sodium Injection System, the Air Quality Compliance Program, Crist Water Conservation, and Emission Allowances.

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

A. Above Ground Storage Tanks (Line Item 1.12) includes maintenance activities and fees required by Florida's above ground storage tank regulation, Chapter 62 Part 762, F.A.C. Expenses totaling $117,322 are projected to be incurred during 2015.

Q. What activity is included in the Sodium Injection line item?

A. The Sodium Injection System (Line Item 1.16) was originally approved for inclusion in the ECRC in Order No. PSC-99-1954-PAA-EI. The activities in this line item involve sodium injection to the coal supply that enhances precipitator efficiencies when burning certain low sulfur coals at Plant Crist and Plant Smith. Expenses totaling $105,903 are projected to be incurred during 2015 for this line item.

Q. What activities are included in the Air Quality Compliance Program (Line Item 1.20)?

A. This line item includes O&M expenses associated with the capital projects approved for ECRC recovery under the Air Quality Compliance Program. This line item includes the cost of anhydrous ammonia, hydrated lime, urea, limestone and general O&M expenses. The projected 2015 expenses for this line item total approximately $16.6 million which includes $8.1 million for limestone costs associated with operation of the Plant Crist and Plant Daniel scrubbers.

Q. What activities are included in the Crist Water Conservation line item (Line Item 1.22)?

A. The Crist Water Conservation line item includes general O&M expenses associated with the Plant Crist reclaimed water system, such as piping and valve maintenance and pump replacements. Expenses totaling $299,302 are projected to be incurred during 2015 for this line item.

Q. Please describe the emission allowance line items 1.24 and 1.26.

A. These line items include projected allowance expenses for Gulf's generation. Line Items 1.24 and 1.26 include projected expenses for the Annual NOx and $SO_2$ allowances of $97,897 and $350,060 respectively.

Q. Do each of the capital projects and O&M activities that have projected costs in 2015 meet the ECRC statutory guidelines?

A. Yes. The projects included in Gulf's 2015 ECRC projection filing meet the requirements of the ECRC statute and are consistent with the Commission's precedents regarding environmental cost recovery. Each of the capital projects and O&M activities set forth in Mr. Boyett's schedules include only prudent costs that are not recovered through some other cost recovery mechanism or base rates. The projected environmental costs are necessary to achieve and/or maintain compliance with environmental laws, rules, and regulations.

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

A. Yes.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 140007-EI
Date of Filing: April 1, 2014

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

A. My name is Richard Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Regulatory and Cost Recovery 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 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator.

In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Regulatory and Cost Recovery area. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery Department.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to present the final true-up amount for the period January 2013 through December 2013 for the Environmental Cost Recovery Clause (ECRC).

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes, I have.

Counsel: We ask that Mr. Dodd's exhibit consisting of nine schedules be marked as Exhibit No. _____ (RWD-1).

Q. Are you familiar with the ECRC true-up calculation for the period January through December 2013 set forth in your exhibit?
A. Yes. These documents were prepared under my supervision.

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

Q. What is the amount to be refunded or collected in the recovery period beginning January 2015?

A. An amount to be collected of $6,645,915 was calculated, which is reflected on line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $6,645,915 to be collected was calculated by taking the difference between the estimated January 2013 through December 2013 under-recovery of $4,084,856 as approved in FPSC Order No. PSC-13-0606-FOF-EI, dated November 19, 2013, and the actual under-recovery of $10,730,771, which is the sum of lines 5, 6 and 9 on Schedule 2A of my exhibit.

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

A. Schedule 2A shows the calculation of the actual under-recovery of environmental costs for the period January 2013 through December 2013. Schedule 3A of my exhibit is the calculation of the interest provision on the average true-up balance. 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 4A and 5A of your exhibit.

A. Schedule 4A compares the actual O&M expenses for the period January 2013 through December 2013 with the estimated/actual O&M expenses approved in conjunction with the November 2013 hearing. Schedule 5A shows the monthly O&M expenses by activity, along with the calculation of jurisdictional O&M expenses for the recovery period. Emission allowance expenses and the amortization of gains on emission allowances are included with O&M expenses. Any material variances in O&M expenses are discussed in Mr. Vick's final true-up testimony.

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

A. Schedule 6A for the period January 2013 through December 2013 compares the actual recoverable costs related to investment with the estimated/actual amount approved in conjunction with the November 2013 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 recovery period. Recoverable costs also include a return on working capital associated with emission allowances. Schedule 7A provides the monthly recoverable costs associated with each project, along with the calculation of the jurisdictional recoverable costs. Any material variances in recoverable costs related to environmental investment for this period are discussed in Mr. Vick's final true-up testimony.

Q. Please describe Schedule 8A of your exhibit.

A. Schedule 8A includes 31 pages that provide the monthly calculations of the recoverable costs associated with each approved capital project for the recovery period. As I stated earlier, these costs include return on investment, depreciation and amortization expense, dismantlement accrual, property taxes, and the cost of emission allowances. Pages 1 through 27 of Schedule 8A show the investment and associated costs related to capital projects, while pages 28 through 31 show the investment and costs related to emission allowances.

Q. Mr. Dodd, what capital structure, components and cost rates did Gulf use to calculate the revenue requirement rate of return?

A. Consistent with Commission Order No. PSC-12-0425-PAA-EU dated August 16, 2012 in Docket No. 120007-EI, the capital structure used in calculating the rate of return for recovery clause purposes for January 2013 through June 2013 is based on the weighted average cost of capital (WACC) presented in Gulf’s May 2012 Earnings Surveillance Report. For July 2013 through December 2013 the rate of return used is the WACC presented in Gulf’s May 2013 Earnings Surveillance Report. The WACC for both periods includes a return on equity of 10.25%

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
C. Shane Boyett
Docket No. 140007-EI
Date of Filing: July 25, 2014

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida in 2001 with a Bachelor of Science Degree in Business Administration. I also hold a Master's in Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist where I worked for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power's Financial Planning department as a Financial Analyst where I worked until being promoted to my current position of Supervisor of Regulatory and Cost Recovery. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery department.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the estimated true-up amount for the period January 2014 through December 2014 for the Environmental Cost Recovery Clause (ECRC).

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 nine schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibit consisting of nine schedules be marked as Exhibit No. _____(CSB-1).

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 2014 through December 2014 period to be refunded or collected in the period January 2015 through December 2015?

A. The estimated true-up for the current period is an under-recovery of $2,229,940 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 2013 final true-up under-recovery amount of $6,645,915. The sum of $8,875,855 will be collected from customers during the January 2015 through December 2015 period. The detailed calculations supporting the estimated true-up for 2014 are contained in Schedules 2E through 8E.

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

A. Schedule 2E shows the calculation of the estimated under-recovery of environmental costs for the period January 2014 through December 2014. Schedule 3E of my exhibit is the calculation of the interest provision on the average true-up balance. 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 2014 through December 2014 to the projected O&M expenses approved by the Commission in Docket No. 130007-EI. 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 2014 through December 2014 compares the estimated/actual recoverable costs related to investment to the projected amount approved in Docket No. 130007-EI. 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 recoverable revenue requirements associated with each project, along with the calculation of the jurisdictional recoverable revenue requirements. 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 31 pages that provide the monthly calculations of recoverable costs associated with each approved capital investment for the current recovery period. As 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 27 of Schedule 8E show the investment and associated costs related to capital projects, while pages 28 through 31 show 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 as shown on Schedule 9E?

A. Consistent with Commission Order No. PSC-12-0425-PAA-EU dated August 16, 2012 in Docket No. 120007-EI, the capital structure used in calculating the rate of return for recovery clause purposes for January 2014 through June 2014 is based on the weighted average cost of capital (WACC) presented in Gulf's May 2013 Earnings Surveillance Report. For July 2014 through December 2014 the rate of return used is the WACC presented in Gulf's May 2014 Earnings Surveillance Report. The WACC for both periods includes a return on equity of 10.25%.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
C. Shane Boyett
Docket No. 140007-EI
Date of Filing: August 22, 2014

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida in 2001 with a Bachelor of Science Degree in Business Administration. I also hold a Master's in Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist where I worked for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power's Financial Planning department as a Financial Analyst where I worked until being promoted to my current position of Supervisor of Regulatory and Cost Recovery. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery department.

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 2015 through December 2015.

Q. Have you prepared any exhibits that contain 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 Mr. Boyett's exhibit consisting of eight schedules be marked as Exhibit No. _____(CSB-2).

Q. What environmental costs is Gulf requesting for recovery through the Environmental Cost Recovery Clause (ECRC)?
A. As discussed in the testimony of Witness James 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 Order No.PSC-94-0044-FOF-EI 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 Operations and Maintenance (O&M) expenses to be recovered through the ECRC calculated?

A. Mr. Vick has provided me with projected recoverable O&M expenses for January 2015 through December 2015. Schedule 2P of Exhibit CSB-2 shows the calculation of the recoverable O&M expenses broken down between demand-related and energy-related expenses. Schedule 2P also provides the appropriate jurisdictional factors and amounts related to these expenses. All O&M expenses associated with compliance with air quality environmental regulations 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. 110138-EI.

Q. Please describe Schedules 3P and 4P of your Exhibit CSB-2.

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 as well as the monthly costs for emission allowances. From that information, plant-in-service and construction work in progress (non-interest bearing) was calculated. Additionally, 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 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 as shown on 8P?

A. Consistent with Commission Order No. PSC-12-0425-PAA-EU dated August 16, 2012 in Docket No. 120007-EI, the capital structure used in calculating the rate of return for recovery clause purposes is based on the weighted average cost of capital (WACC) presented in Gulf's May 2014 Earnings Surveillance Report. This rate of return used to calculate ECRC revenue requirements includes a return on equity of 10.25 percent for the period January 1, 2015 through December 31, 2015.

Q. How has the breakdown between demand-related and energy-related investment costs been determined in the past?

A. Consistent with Commission Order No. PSC-13-0606-FOF-EI dated November 19, 2013 in Docket No. 140007-EI, investment costs recoverable through ECRC were broken down within the retail jurisdiction based on the 12-MCP and 1/13$^{th}$ energy allocator. The use of this allocator is consistent with cost-of-service studies approved in Gulf's prior base rate cases. 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 2015 through December 2015?

A. The total projected jurisdictional recoverable costs for the period January 2015 through December 2015 is $143,358,252 as shown on line 1c of Schedule 1P of Exhibit CSB-2. This includes costs related to O&M activities of $27,267,857 and costs related to capital projects of $116,090,394 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 2015 through December 2015 and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $152,343,715 for the period January 2015 through December 2015 as shown on line 5 of Schedule 1P of Exhibit CSB-2. This amount includes the recoverable costs related to the projection period and the total true-up cost of $8,875,855 to be collected. Schedule 1P also summarizes the energy and demand components of the requested revenue requirement. These amounts are allocated by rate class using the appropriate energy and demand allocators as shown on Schedules 6P and 7P of Exhibit CSB-2.

Q. Is this data and information presented from the books and records of Gulf Power and kept in accordance with generally accepted accounting principles and practices, and with the provisions of the Uniform 9 System of Accounts as prescribed by this Commission?

A. Yes

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 2012 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 one through nine on Schedule 6P of Exhibit CSB-2.

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 of Exhibit CSB-2 summarizes the energy and demand portions of the total requested revenue requirement. The energy-related recoverable revenue requirement of $35,563,286 for the period January 2015 through December 2015 was allocated using the energy allocator, as shown in column three on Schedule 7P of Exhibit CSB-2. The demand-related recoverable revenue requirement of $116,780,430 for the period January 2015 through December 2015 was allocated using the demand allocator, as shown in column four 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 five.

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 $15.92 monthly for the period January 2015 through December 2015.

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 2015 and will continue through the last billing cycle of December 2015.

Q. Mr. Boyett, does this conclude your testimony?
A. Yes.

(Transcript continues in sequence with Volume 2.)

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

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

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

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

DATED THIS 30th day of October, 2014.

Linda Boles

LINDA BOLES, CRR, RPR
FPSC Official Hearings Reporter
(850) 413-6734