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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 150007-EI

ENVIRONMENTAL COST RECOVERY CLAUSE.
_________________________________/

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER JULIE I. BROWN
COMMISSIONER JIMMY PATRONIS

DATE: Monday, November 2, 2015

TIME: Commenced at 1:18 p.m.
Concluded at 1:24 p.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:

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

JEFFREY A. STONE, RUSSELL A. BADDERS, STEVEN R. GRIFFIN, ESQUIRES, P.O. Box 12950, Pensacola, Florida 32591-2950, appearing on behalf of Gulf Power Company.

DIANNE M. TRIPLETT, ESQUIRE, 299 First Avenue North, St. Petersburg, Florida 33701; and MATTHEW R. BERNIER, ESQUIRE, 106 East College Avenue, Suite 800, Tallahassee, Florida 32301-7740; appearing on behalf of Duke Energy Florida, Inc.

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

JON C. MOYLE, JR., and KAREN PUTNAL, ESQUIRES, Moyle Law Firm, P.A., 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

APPEARANCES (Continued):

J.R. KELLY, PUBLIC COUNSEL; CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL; and PATRICIA CHRISTENSEN, ASSOCIATE PUBLIC COUNSEL, 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 the State of Florida.

JAMES W. BREW, and OWEN J. KOPON, ESQUIRES, Xenopoulos & Brew, P.C., 1025 Thomas Jefferson Street, NW, Eight Floor, West Tower, Washington, DC 20007, appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate - White Springs.

CHARLES W. MURPHY, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission.

MARY ANNE HELTON, ESQUIRE, Advisor to the Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing as advisor to the Florida Public Service Commission.

APPEARANCES (Continued):

CHARLIE BECK, General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee Florida, appearing as General Counsel to the Florida Public Service Commission.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
1	Comprehensive Exhibit List	263	263
2 - 45	As described on Comprehensive Exhibit List	263	263
46	Stipulation/Plant Scholz/ CCR Unit 1	261	262

P R O C E E D I N G S

CHAIRMAN GRAHAM: All right. Good afternoon, everybody. We will call this clause hearing to order, the 2015 clause hearing. Let the record show it is Monday, November the 2nd, and it's probably about three minutes after 1:00.

Staff, if I can get you to read the notice, please.

MS. MAPP: By notice issued October 2nd, 2015, this time and place was set for a hearing in the following dockets: Docket No. 150001-EI, 150002-EG, 150003-GU, 150004-GU, and 150007-EI. The purpose of the hearing was set out in the notice.

CHAIRMAN GRAHAM: All right. Seeing that we have five dockets in front of us, let's take appearances.

MR. BUTLER: John Butler appearing on behalf of Florida Power & Light Company. With me, Maria Moncada, and also enter an appearance for Wade Litchfield. We are in the 01, 02, and 07 dockets.

MR. BERNIER: Good afternoon, Matt Bernier on behalf of Duke Energy Florida in the 01, 02, and 07 dockets. I'd also like to enter an appearance for Dianne Triplett in those same dockets, and John Burnett in the 01 docket.

CHAIRMAN GRAHAM: Thank you.

MR. BEASLEY: Good afternoon, Commissioners. James D. Beasley of the law firm of Ausley & McMullen on behalf of Tampa Electric Company in the 01, 02, and 07 dockets. I would also like to enter an appearance for J. Jeffrey Wahlen and Ashley M. Daniels of the same firm.

MR. BADDERS: Good afternoon. Russell Badders on behalf of Gulf Power Company in the 01, 02, and 07 dockets. And I'd like to also enter an appearance for Jeffery A. Stone and Steven R. Griffin in the same dockets.

MS. KEATING: Good afternoon. Beth Keating with the Gunster Law Firm here today on behalf of FPUC in the 01, 02, and 03 dockets. I'm also here for Florida City Gas in the 03 docket. And in the 04 docket I'm here for FPU, FPU Fort Meade, Indiantown, Chesapeake, and Florida City Gas.

MR. HORTON: Norman H. Horton, Jr., appearing on behalf of Sebring Gas Company in the 04 docket.

MR. MOYLE: Jon Moyle with the Moyle Law Firm appearing on behalf of the Florida Industrial Power Users Group, FIPUG. I'd also like to enter an appearance for Karen Putnal who is with our firm, and we will be in the 01, 02, and 07 dockets.

MR. BREW: Good afternoon. James Brew of the firm of Stone, Mattheis, Xenopoulos & Brew for White Springs Agricultural Chemicals/PCS Phosphate. We're in the 01, 02, and 07 dockets. And I also like to note an appearance for Owen Kopon.

MR. WRIGHT: Good afternoon, Mr. Chairman, Commissioners. Robert Scheffel Wright and John T. LaVia, III, with the Gardner Law Firm on behalf of the Florida Retail Federation in the 001 docket. Thank you.

MR. REHWINKEL: Good afternoon, Commissioners. Charles Rehwinkel, J. R. Kelly, Patty Christensen and Erik Sayler with the Office of Public Counsel in the 01 docket. The same appearances except for Mr. Sayler in the 02, 03, 04, and 07 dockets.

MS. MAPP: Kyesha Mapp for staff in the 03 docket; Suzanne Brownless, Danijela Janjic, and John Villafrate for the 01 docket; Lee Eng Tan and Bianca Lherisson for the 02 docket; Leslie Ames and Kelly Corbari for the 04 docket; and Charles Murphy for the 07 docket.

Staff would also like to note that Peoples Gas System and St. Joe's Gas Company has been excused from this hearing in the 03 and the 04 dockets.

MS. HELTON: Mary Anne Helton. I'm here as your advisor in the all of the dockets.

MR. BECK: And Charlie Beck, General Counsel.

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CHAIRMAN GRAHAM: We will go to Docket No. 7.

MR. MURPHY: Commissioners, there are proposed stipulations on all issues. All parties either agree or take no position on the proposed stipulations that are before the Commission today. In this respect, 11A is nuanced because OPC has reached an agreement with Gulf regarding how to handle Plant Scholz but takes no position on the remainder of that issue. In light of the stipulation, neither Gulf nor OPC wishes to pursue its respective requests for official recognition.

If the Commission decides that a bench decision is appropriate, staff recommends that the proposed stipulation for all issues on pages 26 through 35 of the Prehearing Order should be approved by the Commission. Again, as indicated in the Prehearing Order, all parties either support or do not oppose the proposed stipulations.

CHAIRMAN GRAHAM: Commissioners, time to ask questions, comments, concerns, motions.

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

At this time I'm prepared to move that we approve the proposed stipulations for Issues 1 through 13 for this docket.

CHAIRMAN GRAHAM: It's been moved and seconded, Issues 1 through 13. Any further discussion? Seeing none, all in favor, say aye.

(Vote taken.)

Any opposed? By your action, you've approved the motion.

Okay. Staff, prefiled testimony.

MR. MURPHY: Staff asks that the prefiled testimony of all witnesses be entered into the record at this time as though read. Mr. Badders has an errata sheet for Gulf Witness Vick that should be included in this record, and has been provided to the court reporter and the other parties.

CHAIRMAN GRAHAM: We will move the prefiled testimony of all witnesses into the record as though read. And restate what you said about the errata sheet.

MR. MURPHY: It should be included with the testimony in the record.

CHAIRMAN GRAHAM: Okay. We will do that as well.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 150007-EI

JULY 31, 2015

Q. Please state your name and address.

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

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

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

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

A. Yes.

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 RRL-2 provides the summary and executive summary from 40 CFR Parts 257 and 261 of the Federal Register of the Environmental Protection Agency's ("EPA") Final Rule for Disposal of Coal Combustion Residuals from Electric Utilities.

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 request for recovery through the Environmental Cost Recovery Clause ("ECRC") of a new environmental project, the Coal Combustion Residuals Disposal Project ("the CCR Disposal Project"). Additionally, my testimony provides an update on the status of the CWA 316(b) Rule.

Coal Combustion Residuals Disposal Project

Q. Please describe the environmental law or regulation requiring the CCR Disposal Project.

A. On April 17, 2015, the EPA published in the Federal Register a final rule to regulate the disposal of coal combustion residuals ("CCR") as solid waste under subtitle D of the Resource Conservation and Recovery Act ("RCRA"). This rule establishes minimum criteria for the safe disposal of CCR in landfills and surface impoundments. The rule is self-implementing with an effective date of October 19, 2015. A copy of the summary and executive summary of the final CCR disposal rule from the Federal Register is included as Exhibit RRL-2 to my testimony.

Q. What are coal combustion residuals ("CCR")?

A. CCR are generated from the combustion of coal, including solid fuels classified as anthracite, bituminous, subbituminous, and lignite, for the purpose of generating steam to power a generator to produce electricity or electricity and other thermal energy by electric utilities and independent power producers. CCR includes fly ash, bottom ash, boiler slag, and flue gas desulfurization materials. A description of the types of CCR can be found in the proposed rule (see 75 FR 35137).

Q. What are the requirements of the final CCR Disposal rule?

A. The EPA is finalizing national minimum criteria for existing and new CCR landfills and existing and new CCR surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post-closure care, and recordkeeping, notification, and internet posting requirements.

Q. Please briefly describe the minimum criteria of the final CCR Disposal rule.

A. The minimum criteria required by the final rule and a brief description of each are as follows:

- Location Restrictions – This criteria establishes five location restrictions relating to placement of CCR above the uppermost aquifer, in wetlands, within fault areas, in seismic impact zones, and in unstable areas. Units that do not meet these restrictions can retrofit or make appropriate engineering demonstrations to meet this criteria. The final rule requires owners or operators of existing CCR units that cannot make the required demonstrations to close, while owners or operators of new CCR units and all lateral expansions who fail to make the required demonstrations are prohibited from placing CCR in that unit.

- Liner Design – This criteria is intended to help prevent contaminants in CCR from leaching from the CCR unit and contaminating groundwater.
- Structural Integrity Requirements - To help prevent the damages associated with structural failures of CCR surface impoundments, the final rule establishes structural integrity criteria for new and existing surface impoundments and all lateral expansions.
- CCR Unit Operation – This criteria includes particulate air emissions criteria for all CCR units, run-on and run-off water controls for CCR landfills, hydrologic and hydraulic capacity requirements for CCR surface impoundments and periodic inspection requirements for all CCR units. These criteria were established to prevent health and environmental impacts from CCR units.
- Groundwater Monitoring and Corrective Action – This criteria requires an owner or operator of a CCR unit to install a system of monitoring wells and conduct periodic monitoring. Also included are specific procedures for sampling these wells, methods for analyzing the groundwater data collected to detect the presence of hazardous constituents (e.g., toxic metals), and other monitoring

parameters (e.g., pH, total dissolved solids) released from the units. The final rule establishes a groundwater monitoring program consisting of detection monitoring, assessment monitoring and corrective action.

- Closure and Post-Closure Requirements – This criteria requires all CCR units to close in accordance with specified standards and to monitor and maintain the units for a period of time after closure, including the groundwater monitoring and corrective action programs. This criteria was included to ensure the long-term safety of closed CCR units. Closure of a CCR unit must be completed either by leaving the CCR in place and installing a final cover system or through removal of the CCR and decontamination of the CCR unit. The final rule establishes timeframes to initiate and complete closure activities, and authorize owners or operators to obtain time extensions due to circumstances beyond the facility's control. Owners and operators are required to prepare closure and post-closure care plans describing these activities.
- Record Keeping, Notification, and Internet Posting Requirements - The final rule requires the owner or operator of CCR units to record certain information in the facility's operating record. In addition, owners and operators are required to provide notification to States and/or appropriate Tribal authorities when the owner or operator

places information in the operating record, as well as to maintain a publicly accessible internet site for access to this information.

- Severability – The EPA intends that the provisions of this rule be severable. In the event that any individual provision or part of this rule is invalidated, the EPA intends that this would not render the entire rule invalid, and that any individual provisions that can continue to operate will be left in place.

Q. How will the final CCR Disposal rule impact FPL?

A. The final rule applies to the following:

- Owners and operators of new and existing landfills and new and existing surface impoundments, including all lateral expansions of landfills and surface impoundments, that dispose or otherwise engage in solid waste management of CCR generated from the combustion of coal at electric utilities and independent power producers.
- CCR units located off-site that receive CCR for disposal from electric utilities' or independent power producers' facilities.
- Certain inactive CCR surface impoundments (i.e., units not receiving CCR after the effective date of the rule) at active electric utilities' or independent power producers' facilities, regardless of the fuel currently used at the facility to produce electricity (e.g. coal, natural gas, oil), if the CCR unit still contains CCR and liquids.

Based on the above applicability criteria, the final rule will apply to Plant Scherer and St. John's River Power Park ("SJRPP"), in which FPL has an ownership interest. The Plant Scherer ash impoundment is an unlined unit for disposal of ash that cannot be beneficially reused. This unit will require additional engineering demonstrations to show compliance with the location restrictions and final rule's performance criteria. If the demonstrations are not made, or indicate that the impoundment does not meet any of the new performance criteria, early closure of the impoundment and development of a new waste storage unit will be required.

SJRPP utilizes an unlined landfill for the storage of CCR that cannot be beneficially used. The final rule requires an engineering demonstration that SJRPP is not on an unstable formation and meets the final rule's performance criteria for groundwater protection. Failure to meet the new performance criteria will require closure or retrofit of SJRPP with liners.

Q. Please describe FPL's proposed activities associated with the CCR Disposal Project.

A. FPL, along with the operating agents Georgia Power Corporation ("GPC") for Plant Scherer and SJRPP, will initiate the necessary actions to meet the new design and performance requirements of the final rule. At both Plant Scherer and SJRPP a new groundwater monitoring and corrective action plan will be developed and additional groundwater monitoring wells will be installed over the next two years. Over the next three years both Plant Scherer and SJRPP must conduct a number of engineering evaluations to meet the demonstrations required for continued use of the impoundment and landfills. The engineering evaluations include safety factor assessments, location evaluations, development of a new closure plan design, and identification and design of new storage facilities that will be needed at the time the unlined units are closed.

The development of the closure and post-closure care plan is required to be completed by October, 2016. In the event the engineering studies (to be completed by October, 2018) determine that the impoundment or landfills at either SJRPP or Plant Scherer do not meet the design or performance standards, closure will be initiated within six months in accordance with the post-closure care plan.

Q. What is FPL's projected capital investment costs associated with the CCR Disposal Project?

A. FPL's preliminary estimate for its ownership share of capital investment costs associated with the CCR Project for both Plant Scherer and SJRPP combined is approximately $8 million. Proposed activities include engineering studies, plan development, CCR transport system modifications, groundwater monitoring well design, monitoring well installation and periodic monitoring, and new CCR waste management unit design. In the event the ash impoundment at Plant Scherer is forced to enter preliminary closure requiring conversion to full dry ash management and construction of dry ash storage, FPL's ownership share of associated costs are projected to be $42 million.

Q. What are FPL's projected O&M costs associated with the CCR Disposal Project?

A. FPL and its operating agents for Plant Scherer and SJRPP do not anticipate O&M costs to begin until at least 2023. At that time, O&M costs are anticipated for post-closure care, maintenance, and monitoring. Actual expenses will be dependent on the design of the post-closure plan to be developed under the final rule.

Q. How will FPL ensure that the costs incurred for the CCR Disposal Project are prudent and reasonable?

A. For each of its co-owned coal plants, FPL will exercise its contractual right under its operating agreements to review and approve contracts greater than specific dollar thresholds defined in the agreements to ensure that each facility is operated in a manner consistent with prudent utility practices.

Q. Is FPL recovering the costs of these activities through any other mechanism?

A. No.

CWA 316(b) Rule Status Update

Q. What is the current status of the CWA 316(b) Rule?

A. On October 14, 2014, the final 316 (b) Rule for Existing Facilities ("Final Rule") became effective.

Q. What is the implementation schedule for the Final Rule?

A. The Florida Department of Environmental Protection ("FDEP") has chosen to integrate the timeline for the completion and submittal of studies and reports required by the Final Rule into the renewal cycle of the affected facilities' National Pollutant Discharge Elimination System ("NPDES") permits. Required studies and reports for facilities whose current NPDES permits expire after July 14, 2018 are due upon submittal of the next NPDES permit renewal application. For facilities with NPDES permits expiring before July 14, 2018, required studies and reports are due to be submitted no later than 180 days prior to the expiration of the facility's permit (i.e. with the permit renewal application).

The FDEP will determine the Best Technology Available ("BTA") to minimize adverse environmental impacts at each facility as part of the next permit renewal for that facility, and implement compliance schedules for any required activity to achieve BTA in the renewal permit. The new requirements could result in new capital construction, operational changes, or other modes of compliance to meet the permit requirements.

Q. What are FPL's cost estimates for the required studies to determine BTA for FPL's affected facilities?

A. FPL's current O&M cost estimates for the completion of studies and reports for all FPL facilities is approximately $3.7 million. Required activities resulting from these reports will be completed over the 2015-2021 timeframe during the permit renewal process for each facility.

Q. Does FPL anticipate that there will be further court challenges to the Final Rule?

A. Yes. Rule challenges by environmental groups are almost certain as the Final Rule does not require closed-cycle cooling for minimizing entrainment mortality. The environmental groups participated in litigation against the EPA with the previous 316 (b) Phase II Rule issued in 2004, asserting that closed-cycle cooling should be BTA. As with the Final Rule, the prior rule also did not consider closed-cycle cooling to be BTA in all cases. Regardless of the outcome of any challenge to the Final Rule, FPL must proceed with the required studies until such time as the Final Rule is stayed or a decision is made by the Second Circuit Court of Appeals that would negate the requirements of the Final Rule.

Q. Has FPL initiated a new activity required by the Final Rule?

A. Yes. FPL has installed a temporary barrier fence in front of the coarse bar screens and the intake canal of the Cape Canaveral Energy Center ("CCEC") to address the impingement of horseshoe crabs.

Q. Please briefly describe the situation that is requiring this activity at the CCEC.

A. Condition I.C.8 of the CCEC State Industrial Waste Water Permit ("IWW") FL0001473, issued on February 11, 2011, requires the CCEC to comply with the FDEP's Best Professional Judgment for implementing the Final Rule and requires the development of a plan to return live fish, shellfish, and other aquatic organisms collected or trapped on the plant intake screens to their natural habitat. Horseshoe crabs are included in the definition of shellfish.

In early 2014, an unusually large number of horseshoe crabs were being impinged on the coarse bar screens in front of the individual plant intake wells at the CCEC, resulting in an elevated mortality rate.

On July 16, 2014, FPL submitted an email to the FDEP proposing, in order to comply with permit conditions contained in the CCEC's IWW permit and the Final Rule, to construct a barrier to direct horseshoe crabs away from the intake area. In that note, FPL stated that it was seeking concurrence that "…such barrier or some other means of protection for the Horseshoe Crab is appropriate and necessary under the CCEC permit conditions and CWA 316 (b)". On July 21, 2014, the FDEP responded that, "From an NPDES permit perspective, this measure appears to be appropriate for meeting the requirements of the NPDES permit" and directed FPL to work with the Florida Fish and Wildlife Conservation Commission ("FWC") and other agencies to come up with a solution to reduce the number of impinged horseshoe crabs at the CCEC. In response, FPL installed a temporary barrier fence at the entrance to the intake canal, which has been moderately successful in reducing the number of horseshoe crabs being impinged. FPL is manually returning those impinged horseshoe crabs to the Indian River.

Q. What further steps are required at the CCEC to remain in compliance with the State IWW Permit and the Final Rule?

A. In order to comply with the FDEP's BTA, in July, 2015, FPL met with the FWC and other state and federal agencies to propose a modification to the design and location of the current barrier fence to further improve its effectiveness in preventing horseshoe crabs from entering the intake area. The new permanent barrier design will be constructed of concrete rather than wire and will be significantly more effective in reducing the ability of the horseshoe crabs to climb over the current temporary fence. Additionally, the new barrier location will prevent horseshoe crabs from being entrapped in the fuel oil barge unloading area prior to entering the intake canal so they will have less of an opportunity to get beyond the barrier. FPL will remove the temporary barrier fence upon completion of the installation of the permanent concrete barrier.

Should the modified barrier design and location not achieve an adequate reduction (i.e. BTA as determined by the regulatory agencies) in horseshoe crab impingement mortality, FPL will work with the regulatory agencies to determine a more effective solution, such as a return system where horseshoe crabs are removed from the plant intakes and immediately returned to the water instead of being manually relocated.

Q. What are FPL's actual and projected costs associated with this activity?

A. In 2014 FPL incurred $37,191 of O&M expenses associated with the engineering study resulting in the temporary barrier fence. FPL is projecting to spend approximately $231,000 in additional O&M expenses for inspection of the temporary fence and relocation of any horseshoe crabs that become impinged before the installation of the permanent concrete barrier is completed.

FPL intends to begin engineering and permitting of the permanent concrete barrier in 2015 with construction likely in 2016. FPL's capital investment costs for the concrete barrier are projected to be approximately $0.5 million.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 150007-EI

AUGUST 31, 2015

Q. Please state your name and address.

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

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

A. I am employed by NextEra Energy, Inc. ("NEE") as Vice President of Environmental Services.

Q. Have you previously testified in this docket?

A. Yes.

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

A. The purpose of my testimony is to present the Commission with updates on FPL's Greenhouse Gas Reduction ("GHG") Project, an additional activity associated with FPL's Manatee Temporary Heating System Project at the Cape Canaveral Energy Center ("CCEC") and an update to the Turkey Point Cooling Canal Monitoring Plan ("TPCCMP") Project.

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

A. Yes. I am sponsoring the following exhibits:

- RRL-3 – Letter from United States Fish and Wildlife Service ("USFWS") requiring action for manatee protection at the CCEC
- RRL-4 – Proposed conceptual changes to the manatee heating system at the CCEC

<u>GHG Reduction Project Update</u>

Q. Please provide an update on FPL's GHG Reduction Project.

A. In FPL's Environmental Cost Recovery actual/estimated true-Up testimony for the period January 2014 through December 2014, I provided an update on the status of FPL's GHG Reduction Project. At that time the Environmental Protection Agency ("EPA") had recently proposed its GHG performance standards for existing power plants, referred to as the Clean Power Plan ("CPP"). The draft CPP rule proposed that all of FPL's existing fossil fuel fired power plants would be subject to the rule requirements with the exception of its peaking combustion turbines. In the draft rule, the EPA established an interim goal for Florida (2020 – 2029 average) of 794 lb. CO_2/MWh with a final goal of 740 lb. CO_2/MWh by 2030. The EPA calculated Florida's 2012 baseline emission rate for existing units at 1,221 lb. CO_2/MWh, which would require a more than 36% reduction to achieve the EPA's 2030 goal for the state of Florida.

The EPA based those limits on what was defined as Best System of Emission Reduction ("BSER") for affected units. The EPA applied this

BSER requirement on an electric generation system-wide basis, with the goal of achieving a 30% system-wide reduction in GHG emissions in 2030 using a 2005 year baseline. The EPA's four main building blocks for BSER and their associated emission reduction assumptions were:

1. Increase fuel efficiency of coal fired power plants by 6%.
2. Increase dispatch of existing Natural Gas Combined Cycle units to achieve a 70% capacity factor, proportionately reducing coal, oil and natural gas steam generation.
3. Include non-emitting generation in the calculation of state emission rates including new nuclear, 6% of existing nuclear generation, and existing and new development of renewable generation.
4. Reduction of electric consumption (and hence generation) through energy efficiency and demand side management by 1.5% annually through 2030.

On August 3, 2015 the EPA issued its final CPP rule for existing sources along with a proposed Federal Implementation Plan ("FIP") and Model Trading rules.

Q. What changes did the final CPP rule make to the proposed rule?

A. While the EPA has not yet published the final CPP rule in the Federal Register, the Pre-Publication Rule as signed by the EPA Administrator contains several major changes that will result in a final nation-wide CO_2 reduction of 32%, in contrast with the 30% reduction in the proposed CPP rule. The final CPP rule adjusts the state specific targets for reductions, timing for compliance by affected sources, and the building block approach that the EPA had included in the proposed CPP rule. As a result of corrections made to the baseline data, and the changes to the methodology that the EPA used in establishing its BSER approach, the interim and final goals for states changed in the final CPP rule. While several states have revised standards that are more restrictive, the EPA's approach under the final CPP rule resulted in a relaxation of Florida's standards with an interim goal of 1,023 lb/MWh and a final goal of 919 lb/MWh. Additionally, to address concerns raised by the industry regarding the state's interim goal, the EPA's final CPP rule provides for the step-wise implementation schedule to begin in 2022, two years later than originally proposed.

The final CPP rule provides states with three compliance deadlines: 2022–2024, 2025–2027, and 2028–2029, with lower targets for each successive step until reaching the 2030 final goal. The final CPP rule also changes the EPA's building block approach by eliminating proposed building block 4 (energy efficiency) from the state target setting requirements. The final CPP rule also reduces the assumed energy efficiency improvements at existing coal-fired power plants in building block 1 from a nation-wide factor of 6% to a regional specific factor of 4.3% for the Eastern interconnection (this applies to units in Florida and Georgia, among other states).

Other changes include step-wise increases in the assumed use of natural gas combined cycle units on a regional basis in lieu of state wide increases, and crediting only incremental and new renewable and nuclear generating units for use by states in achieving their targets. To incentivize new renewable and energy efficiency projects, the EPA created an early action incentive program that is available for projects built after the state submits its State Implementation Plan ("SIP") for approval. Emission Reduction Credits from these early action incentive projects can be used to offset CO_2 emissions occurring after the 2022 compliance start date of the rule. The EPA's final CPP rule also provides states with an option of meeting a mass (i.e., total ton) limit for fossil generating units and provides a model cap-and-trade rule that states can adopt in their rule implementation plans.

Q. Is FPL developing its strategy to comply with the final CPP rule requirements?

A. Yes. FPL is reviewing the final CPP rule but will not know what additional compliance requirements will be needed until Florida proposes a SIP or the EPA imposes a FIP, should the state not submit an approvable SIP. FPL has reviewed its recent fossil fleet CO_2 emissions and concluded that the current system-wide rate is lower than the EPA's final 2030 target for Florida. However, should the EPA or the DEP require FPL to meet a more stringent rate, further emission reductions that would occur as a result of adding new nuclear generation and renewables may be necessary.

Q. Does FPL intend to submit comments or otherwise engage the EPA and the DEP on development of the proposed FIP rule that was released with the final CPP rule, as well as Florida's plans to implement the final CPP rule?

A. Yes. FPL is actively participating with industry groups including the Edison Electric Institute, the Clean Energy Group, and the Class of '85 Regulatory Response Group to provide comments to the EPA's proposed FIP rule and seek clarification on various aspects of the final CPP rule. FPL also plans to work closely with the DEP in the development of its state plan and associated state rule development to implement the final CPP rule. FPL is aware that several states and industry petitioners have filed legal challenges to certain aspects of the final CPP rule including the EPA's authority to regulate GHGs from existing units under §111(d), its proposed BSER for states and affected units, and its proposed options that may allow new units to be included within the final CPP rule.

<u>CCEC Manatee Temporary Heating System Update</u>

Q. Please briefly describe the current status of the manatee heating system at the CCEC.

A. FPL is subject to specific and continuing legal requirements to provide a warm water refuge for endangered manatees at the CCEC. Specific Condition 13 of the CCEC's State Industrial Wastewater Facility Permit Number FL0001473, issued on February 24, 1999, states that the CCEC must submit a Manatee Protection Plan ("MPP") with each subsequent permit application. The current MPP, previously approved by the Florida Fish and Wildlife Conservation Commission ("FWC") and the USFWS, is dated August 8, 2000. In order to comply with this MPP during the CCEC modernization project, FPL installed a temporary manatee heating system to provide a warm water refuge for manatees while the plant was shut down for the modernization project, as directed by correspondence from USFWS dated June 24, 2008. This system uses an area adjacent to the CCEC intake canal, which of course was not in operation when the plant was shut down for the modernization project. In order to maximize the efficiency of the manatee heating system, FPL installed a divider wall that restricted the heated water to a limited portion of the intake canal and hence reduced the amount of water that needed to be heated.

Originally, FPL expected that the manatee heating system would only be needed during the time that CCEC was shut down for the modernization project. However, because of the large number of manatees that utilize the CCEC as a warm-water refuge during winter months and the relatively low ambient water temperatures during the manatee season at this location, FPL has kept the manatee heating system operational to serve as a back-up in case the entire CCEC plant needs to shut down for an outage during future manatee seasons. Per the MPP, manatee season runs from November 15 to March 31 each year. As I have explained in prior testimony on the MPP, the obligation to maintain a warm-water refuge continues even when the CCEC is shut down.

Q. Have there been any new developments that impact environmental compliance requirements for the manatee heating system at the CCEC?

A. Yes. Since the modernization of CCEC was completed in 2013 and the intake canal is now back in use, FPL has had to notify the FWC of 17 manatee carcasses that have been retrieved from the CCEC intake wells. The USFWS and FWC were able to determine that some of the manatees died prior to entering the intake canal. It is quite likely that these manatees were impacted by the Unusual Mortality Event ("UME") that took place in the Indian River Lagoon ("IRL") in the 2012-13 timeframe. During this UME, a much larger number of manatees than normal died in the IRL of undermined causes. However, for the remaining manatees, it was not possible to determine if they had died prior to appearing in the wells. It is possible that plant operations may have caused or contributed to the death of some of these manatees.

The MPP states that in order for the CCEC to comply with Tasks 25 and 251 of the USFWS Florida Manatee Recovery Plan, FPL shall develop a plan and procedures addressing potential manatee impacts. In addition, in correspondence dated August 24, 2015, which is provided as Exhibit RRL-3, the USFWS has informed FPL that the impingement of compromised manatees in the intake wells could be considered as "takes" under the Endangered Species Act of 1973 (16 U.S.C. § 1531 et seq) and has directed FPL to take action to develop a solution to preclude future takes.

Q. What action does FPL plan to take to address this issue at the CCEC?

A. In early 2015, FPL retained a consultant to propose options to address the reduction of manatee impingement. FPL met with the FWC and the USFWS during the May-August 2015 time frame to discuss strategies to reduce potential future impacts. FPL concluded that the divider wall installed in the intake canal to limit the volume of heated water required for the manatee heating system had the unintended effect of increasing the velocity of water entering the intake canal by about 50%, once the intake canal went back into operation. Based on evaluation of the proposed options and considering input received at the meetings with USFWS, FPL believes the most cost-effective solution is to move the "manatee heating area" away from the intake wells at the end of the intake canal and thus allow the divider wall to be removed. Exhibit RRL-4 provides a conceptual drawing of the proposed relocated manatee heating area. By removing the divider wall, the velocity of the intake water will be reduced to a rate lower than the original plant intake water velocity, thus substantially reducing the likelihood of manatee impingement.

Q. Has FPL estimated the costs for these additional activities at the CCEC?

A. Based on preliminary in-house estimates, FPL believes total O&M costs associated with the relocation of the manatee heating area will be in the $1.5 million to $2 million range. FPL plans to retain a contractor via the bid process to design, permit, and implement the relocation of the manatee heating area at the CCEC. FPL anticipates the engineering, construction and relocation will be completed by November 15, 2016 (i.e. the start of the 2016-17 manatee season).

<u>Turkey Point Cooling Canal Monitoring Plan Project</u>

Q. What is the current status of FPL's TPCCMP Project?

A. FPL continues to conduct the monitoring and reporting requirements of the TPCCMP, including data collection and publication of periodic reports. Additionally, beginning in 2014 and continuing in 2015, FPL has undertaken activities to deliver new sources of water and remove sediment, both directed at reducing the salinity of the CCS. These activities address salinity reduction requirements in the Administrative Order ("AO") issued by the DEP. During 2015, four water delivery activities are expected to be completed, including the development and installation of three wells east of the CCS (PW-1, SW-1, and SW-2) that will provide additional water to the CCS, and the installation of pumps and pipelines to deliver excess stormwater from the L-31 canal. Sediment removal is being conducted in the CCS, to redistribute the water flow more evenly. Improving the water flow in turn improves the efficiency of the

CCS heat exchange, reducing water temperature and hence evaporation rates in the CCS. A lower evaporation rate contributes to lowering salinity, because evaporation concentrates the salt content in the CCS. The sediment removal also improves the hydraulic connection between the CCS and underlying groundwater, supporting the overall salinity reduction effort.

Q. What TPCCMP activities does FPL plan to undertake in 2016?

A. FPL expects to undertake the following TPCCMP activities in 2016:

- FPL will continue to conduct the monitoring and reporting requirements of the TPCCMP, including data collection and publication of periodic reports.
- FPL plans to continue to pump water from the three wells completed in 2015 and also anticipates being able to receive excess stormwater from the L-31 canal.
- The permits that allow for the use of the excess stormwater from the L-31 contain a number of requirements that FPL is obligated to execute, including ground and surface water sampling as well as administrative requirements to monitor and document water flow from the L-31 canal, which will need to be addressed in 2016.
- FPL plans to install the Upper Floridan Aquifer wells at Turkey Point, once the administrative challenge to that work is resolved.
- FPL plans to continue the CCS sediment removal.

Q. What are FPL's cost projections for these 2016 TPCCMP activities?

A. FPL projects that it will incur $28.0 million in O&M and $6.8 million in capital costs in 2016.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 150007- EI

APRIL 1, 2015

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 Clause ("ECR") final true-up amount 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-1 contained in Appendix I consists of nine forms.

- Form 42-1A reflects the final true-up for the period January 2014 through December 2014.
- 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 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 42-9A 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 2014 through December 2014, an under-recovery of $3,164,408, which FPL is requesting to be included in the calculation of the ECR factors for the January 2016 through December 2016 period.

The actual end-of-period under-recovery for the period January 2014 through December 2014 of $1,979,488 (shown on Form 42-1A, Line 3) minus the actual/estimated end-of-period over-recovery for the same period of $1,184,920 (shown on Form 42-1A, Line 6) results in the net true-up under-recovery for the period January 2014 through December 2014 (shown on Form 42-1A, Line 7) of $3,164,408.

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 2014 through December 2014. The end-of-period true-up shown on Form 42-2A, lines 5 plus 6 is an under-recovery of $1,979,488. Additionally, Form 42-3A shows the calculation of the interest provision of $96, which is applicable to the end-of-period true-up under-recovery of $1,979,584.

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 2014 through December 2014 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 $1,102,795, or 4.1% higher than projected and Form 42-6A shows that total capital investment project costs were $480,529 or 0.2% 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 2014 through December 2014 are provided on Form 42-8A, pages 12 through 38.

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". The significant variances in FPL's 2014 expenses relate to the following projects:

O&M Variance Explanations

Project 1. Air Operating Fees

Project expenditures were $47,879 or 37.6% lower than previously projected. The variance is primarily due to lower than projected fossil plant emissions which reduced fees.

Project 3a. Continuous Emission Monitoring Systems (CEMS)

Project expenditures were $350,448 or 34.6% lower than previously projected. The variance is primarily due to the following reasons:

- Replacement of the CEMS umbilical at the Ft. Myers plant was delayed due to timing in the delivery of required materials. The installation is now planned to occur in 2015. Additionally, replacement of umbilicals in the short (bypass) stacks was not required.

- Lower than projected use of oil at the Martin and Manatee plants resulted in lower than expected costs for oil sample analyses.
- Fewer repairs were required at the Sanford plant due to a reduction in the frequency of system leaks resulting from equipment modifications to remove defective permeation dryers.

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

Project expenditures were $698,685 or 23.3% lower than previously projected. The variance is primarily due to fewer than expected mechanical tank repairs on the Manatee fuel oil storage tank (PMT-1371B) as well as the Martin Unit 1 metering tank (PMR M1). During internal and external inspections it was determined that there was no need to make these repairs. In addition, a contractor inadvertently charged his time to Project #23 – SPCC, which should have been charged to Project #5 – Maintenance of Stationary Above Ground Fuel Storage Tanks. A correction and adjustment was completed in February 2015.

Project 13. RCRA Corrective Action

Project expenditures were $8,000 or 35.1% lower than previously projected. The variance is primarily due to a delay by the Florida Department of Environmental Protection ("FDEP") to grant closure of the diesel spill sites using administrative controls (deed restrictions). As a result, FPL cannot yet develop the additional documentation necessary for closure.

Project 17a. Disposal of Non-Containerized Liquid Waste

Project expenditures were $391 or 61.2% higher than previously projected primarily due to unanticipated maintenance on ash press equipment.

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

Project expenditures were $487,806 or 23.0% lower than previously projected. The variance is primarily due to delays in obtaining equipment clearances (i.e., de-energize equipment), which resulted in a lower than projected number of transformers being repaired during 2014.

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

Project expenditures were $730,667 or 29.9% lower than previously projected. The variance is primarily due to delays in obtaining equipment clearances (i.e., de-energize equipment), which resulted in a lower than projected number of transformers being repaired in 2014.

Project 22. Pipeline Integrity Management

Project expenditures were $120,808 or 24.5% lower than previously projected. The variance is primarily due to a delay in the completion of port construction activities by the Port Authority, which resulted in delayed dock unloading pit work at the Port of Palm Beach necessary to allow vessels to unload fuel oil. Without the ability to receive a vessel, the TMR-30 Pipeline could not be on-line for the planned pipeline inspection. The pipeline inspection requires the inspection tool to be propelled down the pipeline as an oil cargo is received and conveyed to the Martin Fuel Terminal.

Project 23. Spill Prevention, Control & Countermeasures – SPCC

Project expenditures were $94,471 or 8.0% lower than previously projected. The variance is primarily due to lower than projected engineering costs for containment at the Martin site. This was partially offset by a contractor inadvertently charging his time to project #23 – SPCC, which should have been charged to project #5 - Maintenance of Stationary Above Ground Fuel Storage Tanks. A correction and adjustment was completed in February 2015.

Project 24. Manatee Reburn

Project expenditures were $137,307 or 41.9% lower than previously projected. The variance is primarily due to fewer than anticipated repairs to the Manatee reburn system as a result of lower than projected use of fuel oil.

Project 28. CWA 316(b) Phase II Rule

Project expenditures were $271,995 or 59.0% lower than previously projected. The variance is primarily due to the FDEP revising its implementation schedule after the 316(b) Existing Rule became effective on October 14, 2014. The projected expenditures are expected to be incurred in 2015 or later.

Project 30. HBMP

Project expenditures were $2,573 or 10.9% higher than previously projected. The variance is primarily due to an increase in the monthly monitoring cost adjusted for the annual cost of living adjustment by the vendor.

Project 31. CAIR

Project expenditures were $56,355 or 1.1% lower than previously projected. The variance is primarily due to lower than projected costs for the 800 MW cycling project at the Martin plant. Lower chemical costs and reduced water treatment costs resulted from the purchase of equipment in lieu of equipment lease expenses. In addition, a reduction in ammonia costs at Plant Scherer Unit 4 resulted from improved tuning of the SCR ammonia injection system for NOx control that was partially offset by higher than projected limestone costs for SO_2 removal compliance requirements that resulted from burning coals with higher than originally estimated sulfur content. FPL also had lower than projected legal expenses, which resulted from the Supreme Court's decision on the challenge of the Environmental Protection Agency's ("EPA") final Cross State Air Pollution Rule ("CSAPR").

Project 32. BART

Project expenditures were $6,000 or 100.0% lower than previously projected. The variance is due to planned consultant work that was no longer needed following the EPA's acceptance of the FDEP's Regional Haze and BART State Implementation Plan.

Project 33. MATS Project

Project expenditures were $312,096 or 21.6% higher than previously projected. The variance is primarily due to baghouse overhaul costs that were not included in the 2014 projections. The overhaul of the baghouse included the replacement of bags for collection of mercury sorbent, maintenance of mechanical and air pulse jet systems, and maintenance of the sorbent storage silo.

Project 35. Martin Plant Drinking Water System Compliance

Project expenditures were $9,389 or 31.1% higher than previously projected. The variance is primarily due to an increase in monthly charges to clean the nano-scale filters on the potable water system. Additionally, the annual fee to provide 40 cubic feet of activated carbon for the potable water plant was inadvertently excluded from original projections.

Project 38. Space Coast Next Generation Solar Energy Center

Project expenditures were $22,976 or 10.1% lower than previously projected. The variance is primarily due to a delay in the replacement of fans that had begun to fail at the sister site of Desoto, but fortunately have not failed at Space Coast. Currently, FPL believes replacement will take place at the end of the fans' life cycle. In addition, staffing was reduced during the first six months.

Project 39. Martin Next Generation Solar Energy Center

Project expenditures were $71,035 or 1.8% lower than previously projected. The variance is a result of fewer than expected seal failures on the heat transfer pumps. Failures were reduced in the second half of 2014 by increasing pump speed on startup, which reduced the amount of friction the seals experience.

Project 40. Greenhouse Gas Reduction Program

Project expenditures were $19,988 or 69.3% lower than previously projected. The variance is primarily a result of not incurring planned consultant costs for analysis of the EPA's Clean Power Plan from existing fossil-fueled electric generating units until after 2014. FPL had anticipated the use of an outside consultant to analyze and assist FPL in the preparation of rule comments, but decided not to pursue this option and instead participated through industry groups.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project expenditures were estimated to be $4,225,507 or 264.5% higher than previously projected. As a Condition to the Site Certification for the Units 3 and 4 Extended Power Uprate (2008), the South Florida Water Management District ("SFWMD") required that FPL establish an extensive Cooling Canal System ("CCS") monitoring program to collect data regarding the interaction of hyper-saline CCS water and the surrounding groundwater. This project was approved to recover costs incurred in connection with the monitoring program, including any corrective measures that might be required as a result of it.

Based on the data collected under this monitoring program, the FDEP, in consultation with SFWMD and Miami Dade County ("MDC"), developed a draft Administrative Order ("AO") that was first shared with FPL for comments in the Summer of 2014 and Fall of 2014. The draft and, ultimately, the final AO that was issued by the FDEP on December 23, 2014, directed FPL to reduce salinity in the CCS and identified a series of potential measures that FPL could include in its Salinity Management Plan. One of those potential measures is the use of storm water from the nearby L-31E Canal, when and if it is available during the wet season (generally, from June – October). When available, storm water is an exceptionally cost-effective means of salinity reduction because it is much less saline than other potentially available sources of water.

FPL became aware in September of 2014 of a limited window of opportunity to make use of this cost-effective source of low salinity water (the L-31E Canal), with the next potential opportunity not available until June 2015 at the earliest. FPL worked with the FDEP, SFWMD and MDC to obtain approvals to pump L-31E Canal water into the CCS between September 26 and October 15, 2014. This initiative was extremely positive, reducing average salinity in the CCS from 87 parts per thousand to less than 75 parts per thousand in just 20 days.

Project 45. 800 MW Unit ESP

Project expenditures were $246,831 or 33.8% lower than previously projected. The variance is primarily due to less run time on fuel oil than originally planned at the Manatee plant. In addition, at the Martin plant there were no maintenance costs in 2014. Any equipment failures were covered under warranty.

Project 46. St. Lucie Cooling Water Discharge Monitoring

Project expenditures were $53,625 or 13.5% lower than previously projected. The variance is primarily due to a delay in sampling, which was originally scheduled for December of 2014 and delayed until January 2015 due to weather constraints. The variance is also partially attributed to lower than originally estimated contracted project manager costs.

Project 48. Industrial Boiler MACT

Project expenditures were $6,536 or 65.4% lower than previously projected. The variance is a result of lower than originally estimated contractor costs for the EPA required energy assessment of the Martin Terminal fuel oil heaters.

Project 49. Thermal Discharge Standards

Project expenditures were $49,557 or 26.3% lower than previously projected. The variance is primarily due to the delayed release of Indian River seagrass coverage data because of a lack of agency funding for subcontractors and project support. In turn, the delayed availability of the data delayed completion of the study report for the Cape Canaveral plant. As a result, some expenses previously projected to be incurred in 2014 will be incurred in 2015.

Project 50. Steam Electric Effluent Guidelines Revised Rules

Project expenditures were $85,302 or 568.7% higher than previously projected. The variance is primarily due to FPL's portion of the cost of studies conducted by Georgia Power Company for Plant Scherer to assess the compliance costs that will be incurred due to the various revised steam effluent guidelines. The operating agent did not provide FPL with a cost estimate for these studies until the fourth quarter of 2014 so there was no amount included in either the original 2014 projections or the actual/estimated true up for this project.

Project 51. Gopher Tortoise Relocation Project

Project expenditures were $12,213 or 42.1% lower than previously projected. The variance is due to lower than projected gopher tortoise relocations at the Martin, Manatee and Sanford sites.

Project 52. Numeric Nutrient Criteria Water Quality Standards in Florida

Project expenditures were $1,248 or 98.5% lower than previously projected. The variance is primarily due to the fact that estimates were based on a worst case scenario in which multiple plants may have had to perform biological and effluent monitoring and change the types of chemicals used and discharged from power plant operations to alter the amount of nutrients (i.e. nitrogen and/or phosphorus) present in the effluent. To date, the State of Florida has not implemented the final Numeric Nutrient Criteria rule. Final rule implementation will occur in 2015. The FDEP is creating a process and schedule for rule compliance.

Capital Variance Explanations

Project 5b. Maintenance of Stationary Above Ground Fuel Storage Tanks

Project depreciation and return on investment were $61,617 or 6.4% lower than previously projected. The variance is primarily attributed to a change in the in-service date of upgrades to the fuel storage tank at the Martin site. This work, which includes upgrading the tank's roof and installation of a secondary containment anchorage system has been delayed until 2015.

Project 21. St. Lucie Turtle Nets

Project depreciation and return on investment were $156,319 or 56.0% lower than previously projected. The variance is primarily attributed to a change in the in-service date of the installation of the permanent turtle net barrier structure from October 2014 to January 2015.

Project 31. CAIR

Project expenditures were $110,197 or 0.2% lower than previously projected. The variance is primarily due to credits received from Georgia Power

Company for plant common construction costs for the Flue Gas Desulfurization ("FGD") Selective Catalytic Reduction ("SCR") pollution control devices installed on Scherer Unit 4 to comply with the Georgia Multi-Pollutant rule and the CAIR.

Project 36. Low-Level Radioactive Waste Storage

Project depreciation and return on investment were $321,127 or 28.1% lower than previously projected. The variance is primarily due to a change in the in-service date of the construction of the low-level radioactive storage facility at the Turkey Point plant from September 2014 to January 2015.

Project 45. 800 MW Unit ESP

Project depreciation and return on investment were $205,737 or 1.0% higher than previously projected. The variance is primarily due to a construction change order for crane mat removal, restoration and re-sequencing of work due to a repair of a fire line rupture; partially offset by the shift of milestone achievements and other construction related cash flow to 2015. The increase affected beginning plant balance thus increasing the return calculation and 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. 150007-EI

JULY 31, 2015

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 2015 through December 2015.

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 2015 through December 2015.

- 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 41 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 2015 through December 2015.

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 2015 through December 2015 is an under-recovery, including interest, of $37,619,712

(Appendix I, Page 2, line 5 plus line 6). This Actual/Estimated True-up amount consists of actual data for January 2015 through June 2015 and revised estimates for July 2015 through December 2015, 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 Coal Combustion Residuals Disposal Project ("the CCR Disposal 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 2015 through December 2015 compare with original projections?

A. Form 42-4E (Appendix I, Page 4) shows that total O&M project costs were $40,408,027 higher than projected, while Form 42-6E (Appendix I, Page 8) shows that total capital investment project costs were $745,686 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 were $284,412 or 101.3% higher than previously projected. Actual fuel consumption for both gas and oil for 2014 (used for 2015 projections) was significantly higher than original projections, which is the primary driver for the cost variance. Additionally, state-required emissions costs per ton increased slightly.

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

Project expenditures were $71,024 or 3.2% higher than previously projected. The variance is primarily due to the API internal inspection of the Martin Unit 2 metering tank, which was not originally budgeted. FPL is implementing the use of a new work management system to improve the budgeting process in order to avoid reoccurrences of similar issues. In addition, work performed in 2014 at the Manatee Terminal was inadvertently charged to the SPCC project. A correcting entry was made in February of 2015.

Project increases were partially offset by lower than projected costs resulting from competitive bidding associated with the painting of the tanks at Ft. Myers Units 1 and 2. The increase was also partially offset by lower than projected costs associated with the API internal inspection of Tank 902 at the Port Everglades plant. Costs associated with tank cleaning were included as part of lease termination activities and therefore were not incurred as part of inspection costs.

Project 17a. Disposal of Non-Containerized Liquid Waste

Project expenditures were $62,369 or 96.0% lower than previously projected. The variance is primarily due to lower than projected processing of ash at the Martin site, resulting from reduced operation at Units 1 and 2.

Project 19a. Substation Pollutant Discharge Prevention and Removal - Distribution

Project expenditures were $705,847 or 38.9% higher than previously projected. The variance is primarily due to obtaining more equipment clearances (i.e., de-energize equipment) than expected, which in turn facilitated a higher than projected number of transformers being repaired during 2015.

Project 19b. Substation Pollutant Discharge Prevention and Removal - Transmission

Project expenditures were $554,316 or 29.9% lower than previously projected. The variance is primarily due to delays in obtaining equipment clearances (i.e., de-energize equipment), which in turn resulted in a lower than projected number of transformers being repaired in 2015.

Project 21. St. Lucie Turtle Nets

Project expenditures were $110,000, whereas no expenditures were projected. The variance is due to costs incurred for inspections and cleaning to remove algae and jellyfish buildup on the net that caused water velocity increases. An increase in water velocity can trap turtles on the net, cause injury and impair their safety.

Project 22. Pipeline Integrity Management

Project expenditures were $466,270 or 120.0% higher than previously projected. The variance is primarily due to deferral of planned smart pig inspections of both Martin pipelines from 2014 to 2015 due to the following:

- To pig the 18” pipeline, FPL needs approximately 200,000 bbls of excess room at the plant tank to accommodate oil used during pigging. Due to the lower price of natural gas versus the price of No. 6 oil, the plant did not burn oil and as a result, there was insufficient capacity available at the plant tank to support pigging the line.
- For the Martin 30” pipeline, there was a delay in the completion of port construction activities by the Port Authority, which resulted in delaying dock unloading pit work at the Port of Palm

Beach required to allow vessels to unload fuel oil. Without the ability to receive a vessel, the Martin terminal 30" pipeline could not be online for planned inline inspection which was scheduled in 2014 and was rescheduled in 2015.

Project 23. SPCC – Spill Prevention, Control & Countermeasures

Project expenditures were $281,195 or 23.3% lower than expected, because work associated with the Maintenance of Stationary Above Ground Fuel Storage Tanks project was inadvertently charged to the SPCC project in 2014. A correcting entry was made in February 2015. Additionally, there was a staffing reduction of one full time and one part time position and an open position has not been filled.

Project 27. Lowest Quality Water Source

Project expenditures were $26,443 or 16.3% lower than previously projected. The variance is primarily due to reduced water supply from our source due to pump issues and the inability to run the water treatment system during unit reliability outages of Sanford Unit 4 and 5 that required switchgear de-energizations needed for preventative maintenance. LQWS usage is anticipated to increase in the coming months due to improvements to that system and as a result of increased water usage in the summer months due to increased unit dispatch. Use of the LQWS, when feasible, is required as a condition of the Water Use Permit in compliance with St Johns Water Management District rules. Cooling pond water at the Sanford Plant is considered LQWS and it use is required to the extent possible, rather than aquifer water. The purpose of the permit limitations for use of aquifer water are for the conservation of higher quality water taken from the environment.

Project 28. CWA 316 (b) Phase II Rule

Project expenditures were $453,555 or 40.3% lower than previously projected. The variance is primarily due to the Florida Department of Environmental Protection's decision to delay the initiation of the compliance requirement until the beginning of the 2015 NPDES permit cycles. Actual compliance-related activities (i.e. strategy development, agency meetings and required studies) commenced for all plants in June 2015. Original estimates assumed that many of the plants' studies would commence in 2014.

Project 30. HBMP

Project expenditures were $5,000 or 22.2% higher than previously projected. The variance is primarily associated with replacement of gauges at each station on the Little Manatee River, which was not included in original projections.

Project 31. Clean Air Interstate Rule ("CAIR") Compliance

Project expenditures were $209,864 or 4.3% lower than previously projected. This was primarily the result of anticipated but not incurred legal and consultant expenses to challenge the provisions of the

EPA's Cross State Air Pollution Rule ("CSAPR"). Following the U.S. Court of Appeals' July 28, 2015 decision to remand to EPA the portions of the rule that affect Florida, FPL did not challenge the CSAPR and therefore did not or will not incur in 2015 any associated expenses. Additionally, costs associated with the Martin 800 MW Cycling Project were lower than projected as a result of lower than anticipated water treatment costs.

Project 33. MATS Project

Project expenditures were $275,909 or 11.6% higher than previously projected. The variance is primarily due to higher than originally estimated consumption of powder-activated carbon due to increased unit operation. This is partially offset by less than originally estimated environmental/legal support services required for MATS compliance.

Project 35. Martin Plant Drinking Water System Compliance

Project expenditures were $38,609 or 146.2% higher than previously projected. The variance is primarily due to the Nano filtration membrane which includes housing, end caps and retaining ring needing to be replaced in 2015 rather than 2016 as originally projected. In addition, there was an increase in vendor charges for monthly cleaning and yearly carbon change-out not previously forecasted.

Project 39. Martin Next Generation Solar Energy Center

Project expenditures were $143,212 or 4.1% higher than previously projected. The variance is a result of the unplanned installation of support brackets at the ball joint locations within the Solar Field Loops. The Martin Solar Team identified that a design modification of the ball joints to include a new support bracket would reduce the stress on the joints and is projected to avoid a majority of the mechanical failures of the joints.

Project 41. Manatee Temporary Heater System

Project expenditures were $35,902 or 10.8% lower than previously projected. The variance is primarily due to lower than originally projected costs for removal of the manatee thermal barrier wall that was installed as part of the Port Everglades Energy Center Manatee Heater project.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project expenditures were $39,906,782 higher than previously projected. These costs are the result of multiple activities related to monitoring and addressing salinity issues within the Cooling Canal System ("CCS") and surrounding groundwater at Turkey Point. The variance is primarily due to costs that are being incurred in 2015 related to compliance with requirements to manage the hypersaline condition that has occurred in the system in recent years. FPL did not have enough information to project these compliance costs in 2014, when the 2015 projections for this project were prepared.

Based on the data FPL has collected pursuant to the CCS monitoring plan, the FDEP, in consultation with the South Florida Water Management District ("SFWMD") and Miami Dade County ("MDC"), issued a final administrative order ("AO") on December 23, 2014; well after FPL had filed its 2015 ECRC projections on August 22, 2014. The AO directs FPL to achieve a substantial reduction in CCS salinity within four years and identifies a series of potential measures that FPL could include in the Salinity Management Plan ("SMP") that FPL must file with the FDEP outlining how it will do so. Under the AO, measures to achieve salinity reduction include: a) delivering new sources of water to the CCS to reduce hyper-salinity, and b) conducting CCS maintenance activities to restore CCS design conditions that will assist in managing salinity. Administrative challenges to the AO are presently pending and so FPL has not yet submitted its SMP. However, owing to the short period of time that FPL will have to achieve the required salinity reductions once the challenges are resolved, FPL has begun taking actions to deliver new sources of water to the CCS and restore the CCS design conditions, two measures that will play a core role in the SMP. FPL does not believe that it could meet the AO's timetable without getting started now (in 2015) with implementation of those measures.

In order to deliver new sources of water to the CCS, FPL is incurring costs for monitoring saline water wells, costs for re-installation and permitting of a piping system to deliver local excess storm water (i.e., continuation of the L31-E Canal activity that was also conducted in 2014), and costs related to pursuing authorizations for six Upper Floridan Aquifer ("UFA") wells authorized by an FDEP Site Certification Modification issued December 23, 2014. It should be noted that the Site Certification for the UFA wells is also under administrative challenge. Costs in this category account for $6,906,782 (or 17%) of the $39.9 million variance.

In order to restore CCS design conditions, FPL is conducting maintenance dredging in the CCS. This dredging will restore design flow distribution and connectivity between the CCS and surrounding groundwater. Modeling performed for FPL to evaluate its AO compliance strategy shows that restoring the design flow distribution, thereby reducing overall CCS temperatures and evaporation rates, and re-establishing connectivity between the CCA and groundwater are essential to creating conditions in which the lower salinity levels required by the AO are realistically achievable. Moreover, the dredging will enable the CCS to better manage salinity during low rainfall periods, thereby allowing FPL to maintain the targeted annual average salinity level required by the AO when rainfall is low. Costs in this category account for the remaining $33.0 million (or 83%) of the $39.9 million variance.

Project 45. 800 MW ESP

Project expenditures were $313,393 or 22.5% lower than previously projected. The variance is primarily due to lower than projected run time on fuel oil than originally planned at the Manatee plant. At the Martin plant, the original budget included four employees charging the project for the entire year but only two employees are currently charging the project and the other two employees were hired in July. This reduces the payroll forecast for 2015. In addition, there was a reduction in maintenance costs because of new equipment and warranty coverage.

Project 46. St. Lucie Cooling Water Discharge Monitoring

Project expenditures were $158,823 or 58.4% lower than previously projected. The FDEP did not require St. Lucie to perform the last round of data collection, which resulted in lower than originally projected fieldwork and project management costs.

Project 49. Thermal Discharge Standards

Project expenditures were $29,357 or 72.4% higher than previously projected. The variance is primarily due to the delayed submittal of the Thermal Plans of Study for both the Cape Canaveral and Riviera

Beach plants. The delays for submitting both studies to the FDEP were attributable to a lack of agency funding for subcontractors and project support for the agencies. As a result of the delays, some expenses projected to be incurred in 2014 were instead incurred in 2015.

Project 50. Steam Electric Effluent Guidelines

Project expenditures were $395,234, whereas no expenditures were projected. The variance is primarily due to invoices associated with FPL's portion of the cost of studies conducted by Georgia Power Company for Plant Scherer to assess compliance costs that will be incurred in anticipation of the implementation of the Steam Electric Guidelines Revisions. This revised rule is anticipated to be released in September 2015. The operating agent did not provide FPL with a cost estimate for these studies until the fourth quarter of 2014 after FPL had filed its 2015 projections.

Project 51. Gopher Tortoise Relocations

Project expenditures were $35,000 or 145.8% higher than previously projected. The increase was due to higher than projected gopher tortoise relocations at the Manatee sites.

Project 52. Numeric Nutrient Criteria Water Quality Standards in Florida

Project expenditures were $38,000, whereas no expenditures were projected. The variance is due to additional expenditures for the Ft.

Myers plant due to the FDEP revisiting the Total Maximum Daily Load ("TMDL") for the Caloosahatchee River, as well as the commencement of implementation of the Numeric Nutrient Criteria ("NNC") for fresh waters. Additionally, consulting expenditures for assistance in verification of compliance with existing Waste Load Allocations for the plant as part of the Indian River Lagoon TMDL were incurred at FPL's Cape Canaveral Plant. NPDES permit applications for both plants are due in 2015 and this information will be submitted as part of the renewal process.

Capital Project Variances

Project 8b. Oil Spill clean-up/Response Equipment

Project depreciation and return on investment were $23,712 or 15.4% lower than previously projected. The variance is primarily due to greater than anticipated retirement of corporate oil spill response equipment at the Manatee site and less than anticipated new equipment needing to be purchased.

Project 21. St. Lucie Turtle Nets

Project depreciation and return on investment were $107,478 or 12.3% lower than previously projected. The variance is primarily attributed to lower vendor implementation costs than originally projected due to favorable contractual terms.

Project 22. Pipeline Integrity Management

Project depreciation and return on investment were $41,498 or 11.6% lower than previously projected. The initial projection included the depreciation and return on investment for the replacement of TMR 18" pipeline block valve actuators as part of the Pipeline Integrity Management Project. Subsequently, it was determined that the original actuators were part of the base pipeline project and thus the costs for the replacement of the valve actuators, and associated depreciation and return on investment, should be treated consistently (base rate capital).

Project 23. Spill Prevention, Control and Countermeasures

Project depreciation and return on investment were $170,803 or 10.2% lower than previously projected. The variance is primarily attributed to a change in the in-service date of the installation of the collection basin at Turkey Point from December 2015 to June 2016.

Project 31. Clean Air Interstate Rule ("CAIR") Compliance

Project depreciation and return on investment were $655,691 or 1.1% lower than previously projected. The variance is primarily due to a reduction in the allocation of Plant Scherer costs for common facility equipment capital additions to Unit 4.

Project 33. MATS

Project depreciation and return on investment were $52,986 or 0.5% lower than previously projected. The variance is primarily due to a reduction in the allocation of Plant Scherer costs for common facility equipment to Unit 4.

Project 39. Martin Next Generation Solar Energy Center

Project depreciation and return on investment were $288,268 or 0.6% lower than previously projected. The variance is primarily due to the result of placing the preheaters into service in 2014 and the unitization/retirements of that project occurring in January 2015 upon final close-out of the work order. The retirement unit was not identified until close out of the work order resulting in timing differences.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project depreciation and return on investment were $257,399 or 58.8% higher than previously projected. The variance is primarily attributed to the addition of two water wells that went into service in June 2015, and six monitoring wells and five monitoring stations expected to go into service in September 2015 that were not reflected in the original projection. This was partially offset by a change in the in-service dates of the Upper Floridan Aquifer ("UFA") and saline water wells at Turkey Point. The UFA wells, which were originally expected to be in service in December 2015, have been delayed to

2016 pending the outcome of administrative challenge.

Project 45. 800 MW Unit ESP

Project depreciation and return on investment were $569,690 or 2.4% higher than previously projected. The variance is primarily due to an actual in-service date for the Martin Unit 2 ESP in December 2014 vs. the originally estimated in-service date of February 2015. This earlier in-service date resulted in higher than estimated depreciation expense and return on investment.

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. 150007-EI

AUGUST 31, 2015

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 2016 through December 2016 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 2016 through December 2016. Exhibit 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 Coal Combustion Residuals Disposal Project ("the CCR Disposal Project"). FPL petitioned the Commission in this docket on July 31, 2015 to approve the CCR Disposal 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 2016 through December 2016. Total environmental requirements, adjusted for revenue taxes, are $270,559,175 (Appendix I, Page 1, Line 5) and include $229,580,392 of environmental project jurisdictional revenue requirements for the January 2016 through December 2016 period (Appendix I, Page 1, Line 1c) increased by the actual/estimated true-up under-recovery of $37,619,712 for the January 2015 through December 2015 period (Appendix I, Page 1, Line 2), and increased by the final true-up under-recovery of $3,164,408 for the January 2014 through December 2014 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 $51,623,952 for the period January 2016 through December 2016.

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 $177,956,440 for the period January 2016 through December 2016.

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 109) 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 110) 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 average of the twelve 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 111) presents the calculation of the proposed 2016 ECRC factors by rate class.

Q. Please describe Form 42-8P.

A. Form 42-8P (Appendix I, Page 112) 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 2016 through December 2016. 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 2015 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. 150007-EI

April 1, 2015

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 or the Company). 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 Corporation (Duke Energy), I was promoted to my current position. Prior to working at Duke Energy I was the Supervisor in the Fixed Asset group at Eckerd Drug. In this role I was responsible for ensuring proper accounting for all fixed assets as well as various other accounting responsibilities. I have 6 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 2014 - December 2014.

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: Final true-up for the period January 2014 - December 2014.
- Form 42-2A: Final true-up calculation for the period.
- Form 42-3A: Calculation of the interest provision for the period.
- Form 42-4A: Calculation of variances between actual and actual/estimated costs for O&M Activities.
- Form 42-5A: Summary of actual monthly costs for the period for O&M Activities.
- Form 42-6A: Calculation of variances between actual and actual/estimated costs for Capital Investment Projects.
- Form 42-7A: Summary of actual monthly costs for the period for Capital Investment Projects.
- Form 42-8A, pages 1-18: Calculation of return on capital investment, depreciation expense and property tax expense for each project recovered through the ECRC.
- Form 42-9A: 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 2-3)

- Above Ground Storage Tank Secondary Containment (CPD, pages 4-9)
- Clean Air Interstate Rule (CAIR) Combustion Turbines (CTs)(CPD, pages 10-13)
- CAIR-Crystal River Units 4 & 5 (CPD, pages 14-15)
- Thermal Discharge Permanent Cooling Tower (CPD, pages 16-17)

These exhibits were developed under my supervision and they 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, 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 2014 - December 2014?

A. DEF requests approval of an over-recovery amount of $12,764,024 for the year ending December 31, 2014. 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 2014 - December 2014 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 $1,419,043 reflected on Line 3 of Form 42-1A, as the adjusted net true-up amount for the period January 2014 - December 2014. This amount is the difference between an actual over-recovery amount of $12,764,024 and an actual/estimated over-recovery of $11,344,981 for the period January 2014 - December 2014, as approved in Order PSC-14-0643-FOF-EI.

Q. Are all costs listed on 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 2014 - December 2014 compare with DEF's actual/estimated projections as presented in previous testimony and exhibits?

A. Form 42-4A shows a total O&M project variance of $1,902,944 lower than projected. Individual O&M project variances are on Form 42-4A. Explanations associated with variances are contained in the direct testimonies of Jeffrey Swartz, Patricia Q. West, and Corey Zeigler.

Q. How did actual capital recoverable expenditures for January 2014 - December 2014 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 $208,084 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 1-18. Explanations associated with variances are contained in the direct testimonies of Michael Delowery, Mr. Swartz and Ms. West.

Q: What effect does the Cross-State Air Pollution Rule (CSAPR) have on the ECRC?

A. As further explained in the direct testimony of Ms. West, the CSAPR became effective on January 1, 2015. The CSAPR establishes new NOx annual and seasonal programs and a new SO_2 trading program (Florida is only subject to the NOx seasonal program). NOx and SO_2 emission allowances under the current Clean Air Interstate Rule (CAIR) cannot be used to satisfy the CSAPR.

In Order No. PSC-11-0553-FOF-EI, dated December 7, 2011, the Commission authorized DEF to establish a regulatory asset to recover the costs of its remaining unusable CAIR NOx allowances over three (3) years with a return on the unamortized investment. As of December 31, 2014, DEF's investment in CAIR NOx emission allowances is $10.3 million (system) as shown on line 1d of Form 42-8A, page 5. Consistent with Order No. PSC-11-0553-FOF-EI, DEF is treating these costs as a regulatory asset and will amortize them over three (3) years beginning January 1, 2015 until fully recovered by December 31, 2017, with a return on the unamortized investment.

The CAIR used Acid Rain program (Title IV of the Clean Air Act) allowances to comply with the SO_2 emission portion of the rule. DEF expects to use its remaining SO_2 emission allowances to comply with the existing Acid Rain program even though the CAIR is no longer in effect.

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. 150007-EI

July 31, 2015

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. 150007-EI?

A. Yes, I provided direct testimony on April 1, 2015.

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) actual/estimated true-up costs associated with environmental compliance activities for the period January 2015 through

December 2015. I also explain the variance between 2015 actual/estimated cost projections versus original 2015 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 actual/estimated true-up capital and O&M environmental costs and revenue requirements for the period January 2015 through December 2015.

Q. What is the actual/estimated true-up amount for which DEF is requesting recovery for the period of January 2015 through December 2015?

A. The 2015 actual/estimated true-up is an under-recovery, including interest, of $779,602 as shown on Form 42-1E, line 4. This amount is added to the final 2014 true-up over-recovery of $1,419,043 as shown on Form 42-2E, Line 7a, resulting in a net over-recovery of $639,441 as shown on Form 42-2E, Line 11. The calculations supporting the 2015 actual/estimated true-up 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 2015 through December 2015?

A. The capital structure, components and cost rates relied on to calculate the revenue requirement rate of return for the period January 2015 through December 2015 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 actual/estimated O&M expenditures for January 2015 through December 2015 compare with original projections?

A. Form 42-4E shows that total O&M project costs are estimated to be $2.2 million higher than originally projected. This form also lists individual O&M project variances. Explanations for these variances are included in the direct testimonies of Garry Miller, Jeffrey Swartz and Patricia Q. West, except for Emission Allowances which is below.

Emissions Allowances (Project 5) – O&M

SO_2 and NOx expenses are estimated to be approximately $1.5 million higher than originally projected. This increase is primarily attributable to unusable NOx emission allowances due to the expiration of the Clean Air Interstate Rule (CAIR) on December 31, 2014. CAIR was replaced by the Cross-State

Air Pollution Rule (CSAPR) on January 1, 2015, as explained in my April 1, 2015 direct testimony. Consistent with Order No. PSC-11-0553-FOF-EI, DEF is treating the costs associated with the unusable NOx emission allowances as a regulatory asset and amortizing it over three (3) years, beginning January 1, 2015, until fully recovered by December 31, 2017, with a return on the unamortized investment.

Q. How do estimated/actual capital recoverable costs for January 2015 through December 2015 compare with DEF's original projections?

A. Form 42-6E shows that total recoverable capital costs are estimated to be approximately $676k higher than originally projected. This form also lists individual project variances. The return on investment, depreciation expense and property taxes for each project for the actual/estimated period are provided on Form 42-8E, pages 1 through 19. Explanations for these variances are included in the direct testimonies of Michael Delowery, Mr. Miller, Mr. Swartz and Ms. West.

Q: Does DEF seek to change the ECRC factors established for 2015 for the recovery of Coal Combustion Residual (CCR) compliance costs?

A: DEF does not seek to change the ECRC factors established in 2014 in Order No. PSC-14-0643-FOF-EI. The Company proposes to include costs incurred in 2015 in the actual/estimated true-up balance. The Company will include program costs projected for 2016 and beyond in the appropriate projection filings.

Q: How will CCR compliance costs be allocated to rate classes?

A: DEF proposes that capital and O&M costs associated with the CCR compliance program be allocated to rate classes on an energy basis.

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, LLC.

DOCKET NO. 150007-EI

August 31, 2015

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. 150007-EI?

A: Yes. I provided direct testimony on April 1, 2015 and July 31, 2015.

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, LLC's ("DEF" or "Company") calculation of revenue requirements and Environmental Cost Recovery Clause ("ECRC") factors for customer billings for the period January 2016 through December 2016. My testimony also addresses capital and O&M expenses for DEF's environmental compliance activities for the year 2016.

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 6-22 as indicated in their direct testimony. I am sponsoring Form 42-5P page 5.

- Ms. West will co-sponsor Forms 42-5P pages 1-4, 6 and 8-19.
- 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.
- Mr. Miller will co-sponsor Form 42-5P page 22.

Q. Please summarize your testimony.

A. My testimony supports the approval of an average ECRC billing factor of 0.182 cents per kWh which includes projected jurisdictional capital and O&M revenue requirements for the period January 2016 through December 2016 of approximately $69.4 million associated with a total of 18 environmental projects, and a true-up over-recovery provision of approximately $0.6 million from prior periods. My testimony also supports that projected environmental expenditures for 2016 are appropriate for recovery through the ECRC.

Q. What is the total recoverable revenue requirement for the period January 2016 through December 2016?

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is approximately $68.8 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 2016 through December 2016?

A. The total true-up applicable to this period is an over-recovery of approximately $0.6 million. This amount consists of the final true-up over-recovery of approximately $1.4 million for the period January 2014 through December 2014, and an estimated true-up under-recovery of approximately $0.8 million for the current period of January 2015 through December 2015. The detailed calculation supporting the 2015 estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. __ (TGF-3) filed with the Commission on July 31, 2015.

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, except for the Coal Combustion Residual Program (Project 18) for which DEF is seeking approval for recovery in this Docket. The following ECRC programs were previously approved by the Commission:

The Substation and Distribution System 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.

As explained in my July 31, 2015 direct testimony, DEF has unusable NOx emission allowances due to the expiration of the Clean Interstate Rule ("CAIR") on December 31, 2014. CAIR was replaced by the Cross-State Air pollution

Rule on January 1, 2105. Consistent with Order No. PSC-11-0553-FOF-EI, DEF is treating the costs associated with unusable NOx emission allowances as a regulatory asset and amortizing it over three (3) years, beginning January 1, 2015, until fully recovered by December 31, 2017, with a return on the unamortized investment.

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 Project (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 Nos. PSC-08-0775-FOF-EI.

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

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

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

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

The Mercury & Air Toxic Standards (MATS) Program (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 2016 through December 2016?

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 2015 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 7a and b.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2016?

A. Yes. Form 42-2P of Exhibit No. __ (TGF-5) summarizes recoverable jurisdictional O&M cost estimates for these projects of approximately $44.2 million.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2016?

A. Yes. Form 42-3P of Exhibit No. __ (TGF-5) summarizes recoverable jurisdictional capital cost estimates for these projects of approximately $25.2 million. Form 42-4P pages 1 through 16 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 22 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 2016?

A. The total jurisdictional capital and O&M costs to be recovered through the ECRC are approximately $69.4 million. The costs 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 on Forms 42-6P and 42-7P of Exhibit No. __(TGF-5). The demand component of class allocation factors is 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 2015. 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 2016 ECRC billing factors by the various rate classes and delivery voltages?

A. The calculation of DEF's proposed ECRC factors for 2016 customer billings is shown on Form 42-7P in Exhibit No. __(TGF-5) as follows:

RATE CLASS	**ECRC FACTORS** **12CP & 1/13AD**
Residential	0.184 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.181 cents/kWh
@ Primary Voltage	0.179 cents/kWh
@ Transmission Voltage	0.177 cents/kWh
General Service 100% Load Factor	0.178 cents/kWh
General Service Demand	
@ Secondary Voltage	0.180 cents/kWh
@ Primary Voltage	0.178 cents/kWh
@ Transmission Voltage	0.176 cents/kWh
Curtailable	
@ Secondary Voltage	0.173 cents/kWh
@ Primary Voltage	0.171 cents/kWh
@ Transmission Voltage	0.170 cents/kWh
Interruptible	
@ Secondary Voltage	0.175 cents/kWh
@ Primary Voltage	0.173 cents/kWh
@ Transmission Voltage	0.172 cents/kWh
Lighting	0.173 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 2016 and continue through the last bill group for December 2016.

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. 150007-EI

April 1, 2015

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 and in what capacity?

A: I am employed by Duke Energy, Inc. (Duke Energy or the Company) as Vice President of Project Management and Construction.

Q: What are your responsibilities in that position?

A: I am the senior manager responsible for oversight of new power plant construction and retrofit of existing fossil and hydro-electric power plants for Duke Energy, including the Anclote Gas Conversion Project.

Q: Please describe your educational background and professional experience.

A: I obtained my Bachelor of Science degree in Mechanical Engineering from Drexel University. I have over 23 years of power industry experience. I joined Duke Energy in May 2011 as General Manager responsible for potential repair of the CR3 containment building. In August 2014, I was appointed to my current position. Prior to 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 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 domestic and international nuclear power stations.

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 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 actual/estimated project expenditures for the period January 2014 – December 2014.

Q. What is the total estimated cost for the MATS – Anclote Gas Conversion Project (Project 17.1)?

A. Consistent with my August 22, 2014 projection testimony in Docket No. 140007-EI, the total estimated project cost is $137 million.

Q. Did the Anclote Gas Conversion Project meet its targeted in-service dates and total estimated cost?

A. Yes, Unit 1 and Unit 2 gas conversions went in service on July 13, 2013 and December 2, 2013, respectively. Unit 1 and Unit 2 Force Draft (FD) fan modification work was completed on May 22, 2014 and November 17, 2014, respectively. Total actual project cost as of 2014 year end is approximately $134 million.

Q. How did actual project expenditures for the period January 2014 – December 2014 compare to actual/estimated projections for the Anclote Gas Conversion Project?

A. The Anclote Gas Conversion capital variance is $783,497 or 2% lower than projected due to earlier than expected completion of Unit 2 FD fan work on November 17, 2014 versus the projected completion date of December 15, 2014.

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. 150007-EI

July 31, 2015

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. Have you previously filed testimony before this Commission in Docket No. 150007-EI?

A: Yes, I provided direct testimony on April 1, 2015.

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 provide an update on the Mercury and Air Toxics Standards (MATS) - Anclote Gas Conversion Project (Project 17.1).

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

A. DEF estimates 2015 capital costs of approximately $509k for the Anclote Gas Conversion project for site/warranty support, completion of punch list items, document control/record management and contract close-out.

Q. Please explain the variance between the actual/estimated project expenditures and original projections for the MATS – Anclote Gas Conversion Program (Project 17.1) for the period January 2015 through December 2015.

A. Capital expenditures for the Anclote Gas Conversion project are estimated to be $314k less than originally projected due to earlier than expected completion of Unit 2 Force Draft (FD) fan work in November 2014 versus December 2014.

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, LLC.

DOCKET NO. 150007-EI

August 31, 2015

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. 150007-EI?

A. Yes. I provided direct testimony on April 1, 2015 and July 31, 2015.

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 2016 for the Mercury and Air Toxics Standards (MATS) - Anclote

Gas Conversion Project (Project 17.1)

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 22 - MATS - Anclote Gas Conversion

Q. What costs do you expect to incur in 2016 in connection with the MATS – Anclote Gas Conversion Project (Project 17.1)?

A. Duke Energy Florida, LLC does not expect any costs in 2016. The project is complete and in-service.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>GARRY MILLER</u>

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 150007-EI

July 31, 2015

Q. Please state your name and business address.

A. My name is Garry Miller. My business address is 400 South Tryon Street, Charlotte, NC 28202.

Q. By whom are you employed?

A: I am employed by Duke Energy, Inc. as Senior Vice President – Ash Basin Strategic Action Team ("ABSAT")- Engineering.

Q: What are your responsibilities in that position?

A: I am on interim assignment in the Ash Basin Strategic Team. My responsibilities are strategic planning to close Duke Energy ash basins, including development of strategic plans, vetting those plans with the applicable regulators, and working with ABSAT Project Management on action plans to implement the strategic plans.

Q: Please describe your educational background and professional experience.

A: I have Bachelor of Science degree in Nuclear Engineering from North Carolina State University. I also have a Master's degree in Mechanical Engineering from North Carolina State University. I have over 30 years of experience in the nuclear industry. My experience involves engineering and maintenance experience at Duke Energy's nuclear plants and the corporate office for nuclear operations. I have held Engineering Manager positions at the Brunswick Nuclear Plant and Robinson Nuclear Plant. I was also the Chief Engineer for the Nuclear Generation Group ("NGG") for Progress Energy. Additionally, I was the Maintenance Manager at the Harris Nuclear Plant. I also hold a BWR/SRO (senior reactor operation) certification. Prior to the merger, I was the Vice President - Nuclear Engineering for Progress Energy. After the merger with Duke Energy, I became Duke Energy's Senior Vice President of Nuclear Engineering. In March of 2014, I began my current interim role as Senior Vice President - ABSAT – Engineering.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain Duke Energy Florida's ("DEF" or the "Company") proposed compliance activities and related costs associated with the new Coal Combustion Residual ("CCR") Rule for which the Company seeks recovery under the Environmental Cost Recovery Clause ("ECRC").

Q: Please summarize the CCR Rule.

A: The CCR rule was published in the Federal Register on April 17, 2015, and is effective on October 17, 2015. The rule regulates the disposal of CCR as non-hazardous solid waste, and contains new requirements for CCR landfills and CCR surface impoundments. It also specifies implementation timelines for compliance. The compliance deadlines for CCR vary, with compliance obligations required as early as October 17, 2015. Compliance timeframes for specific CCR requirements are addressed later in this testimony. The rule is self-implementing, meaning that affected facilities must comply with the new regulations irrespective of whether the rule is adopted by the State of Florida. Even if the state adopts the rule and incorporates its criteria into the state's solid waste management program, the federal rule remains in place as an independent set of criteria that must be met.

The CCR rule applies to new and existing CCR landfills and surface impoundments, including lateral expansions of CCR units. In addition, the rule applies to electric utilities' and independent power producers' *inactive* CCR surface impoundments (those not receiving CCR on or after the effective date of the rule) regardless of the fuel currently used at the facility to produce electricity if the inactive impoundment contains CCR and liquids. If an inactive surface impoundment closes within three years after the rule was published in the Federal Register, either by closure in place or clean closure, it is excluded from further regulation. Inactive CCR surface impoundments that do not close within this timeframe are regulated in the same manner as existing CCR surface impoundments and subject to all rule requirements, including location restriction and groundwater monitoring. The CCR rule does not apply to inactive landfills - i.e. landfills that ceased receiving CCR prior to the effective date of the rule.

Key aspects of the CCR rule include:

1) Location Restrictions – New landfills, including lateral expansions of existing units, and all surface impoundments, including inactive surface impoundments, are subject to location restrictions regarding the placement of CCR units above the uppermost aquifer, in wetlands, within fault areas, in seismic impact zones, and in unstable areas. By October 2018, DEF must perform a location restriction assessment for each landfill and surface impoundment subject to the CCR rule. CCR units must meet the conditions for operating in a location restriction area; units that do not meet the conditions must cease receipt of CCR and, in the case of landfills, commence closure.

2) Liner Design Criteria – New CCR landfills, new lateral expansions of CCR landfills, and new CCR surface impoundments must have a bottom composite liner, with the upper component consisting of a geomembrane liner and the lower component consisting of at least a two-foot layer of compacted soil meeting a specified hydraulic conductivity design standard. Unlined CCR surface impoundments must cease the receipt of CCR and commence closure if it is determined during groundwater monitoring that releases from these impoundments exceed applicable groundwater protection standards. The rule does not include a mandatory liner retrofit requirement for existing, unlined CCR surface impoundments.

3) Surface impoundment Structural Integrity Requirements – CCR surface impoundments are subject to structural integrity requirements that include: undertaking hazard potential assessments, meeting slope erosion standards, maintaining

impoundment construction records, and undertaking structural stability and safety factor assessments. If a surface impoundment does *not* meet specified dam safety factor structural stability assessment requirements by October 17, 2016, it must cease receipt of CCR within 6 months and commence closure.

4) Groundwater Monitoring & Corrective Action – All CCR landfills and CCR surface impoundments that are subject to the CCR rule are subject to groundwater monitoring, and if necessary, corrective action requirements. Within two years of the CCR rule effective date, all existing CCR landfills and existing CCR surface impoundments (subject to the rule) must have installed groundwater monitoring systems and groundwater detection monitoring program initiated.

5) Closure & Post-Closure Care – The CCR rule contains closure and post-closure monitoring plan requirements for new and existing CCR landfills and active and inactive CCR surface impoundments. The rule sets closure standards for closure in place or closure through removal of CCR and decontamination of the CCR unit (clean closure). The CCR rule states that landfills must complete closure within six months of commencement, and surface impoundments must complete closure within five years of commencement. The rule also requires closed units to comply with certain post-closure care requirements.

6) Recordkeeping, Notification & Internet Posting Obligations – Because the CCR rule is self-implementing, the CCR rule contains extensive recordkeeping , notice, and internet posting requirements that must be met by October 17, 2015 to demonstrate

compliance with the rule. These items are intended to provide information to the states and public to continually gauge the compliance status of regulated facilities with the rule's self-implementing requirements.

Q: How does the CCR rule impact DEF's facilities?

A: The rule has specific compliance impacts on the ash landfill, the Flue Gas Desulfurization ("FGD") lined blowdown ponds, and the temporary gypsum storage pad at the Crystal River ("CR") site. No other DEF operating sites are impacted by the CCR rule.

Q: What are the CCR rule compliance activities and associated costs for which DEF is seeking recovery?

A: <u>Ash Landfill</u>

DEF has contracts with two engineering firms to study CR ash landfill stability and ash placement. One firm will perform a geotechnical study of the ash landfill including surveys, field inspections, ash sampling and engineering calculations to determine landfill stability. The other firm will compile and review historical ash placement and testing documents, and develop a process and related procedures to address future ash placement requirements at Crystal River. Total estimated O&M costs for engineering firm work is $104k. Groundwater monitoring will also be required for the ash landfill, Flue Gas Desulfurization ("FGD") blowdown ponds (i.e., CCR surface impoundments), and potentially the gypsum storage pad to comply with the CCR rule. The extent and cost of groundwater monitoring for the ash landfill, FGD blowdown ponds and gypsum storage pad are being assessed; DEF will provide an update in its 2016 Projection Filing.

Temporary Gypsum Pad

Effective October 17, 2015, the temporary gypsum pad at CR will be subject to CCR requirements. Efforts are underway to address fugitive dust mitigation at the CCR gypsum stack-out; upon completion, the CR temporary gypsum pad will no longer be subject to the CCR rule's compliance requirements as a CCR landfill. Total estimated 2015 costs for the addition of a dust control system is $1.5M.

FGD Blowdown Ponds

The CR FGD Blowdown Ponds are subject to the CCR rule, and a definitive assessment and action plan is being developed. The ponds must also be classified as to hazard potential to determine if an Emergency Action Plan ("EAP") is needed to comply with the CCR rule (see EAP below). As addressed above, groundwater monitoring will also be required for the FGD Blowdown Ponds along with weekly inspections, based on the results of the liner assessments required by the rule. DEF estimates that the predicate assessments required by the rule to ascertain if remediation is required will cost approximately $200k in 2015.

Emergency Action Plan

An EAP outlines the notification and remediation process in the event of a dam breach or any event that could impact the environment or public safety at a DEF operating site. An EAP is required per the CCR rule if a surface impoundment is classified as "significant hazard" or "high hazard" potential. DEF is in the process of determining if the CCR rule requires an EAP for the CR FGD Blowdown Ponds. DEF estimates costs of $24k to develop an EAP.

Vegetation Management & Inspection Work

The CCR rule requires increased vegetation management and inspection work at the CR site. Vegetative cover must be no more than six inches above the face of an embankment. The CCR rule requires that the time between inspections at landfills and surface impoundments may not exceed every 7 days, and requires annual inspections of both by an independent party. Moreover, additional weekly and monthly inspections performed by internal personnel are required for surface impoundments. More frequent mowing will be necessary to comply with the 6 inch requirement. Incremental costs required to comply with these requirements are estimated at $64k for July – December 2015.

Additional capital costs in 2015 to comply with the vegetation management requirements are $100k.

Q: Are there any other CCR rule compliance activities and costs for which DEF expects to seek recovery?

A: DEF is currently evaluating the CCR rule to determine operating and cost impacts, and expects to incur compliance costs in 2015 and beyond. However, the full extent of compliance activities and associated costs cannot be determined until further analysis and assessments of the CCR rule are complete. DEF will provide an update on its CCR program in its 2016 Projection Filing.

Q: Do DEF's expected CCR compliance activity costs meet the recovery criteria established by Order No. 94-044-FOF-EI?

A: Yes. The proposed CCR program meets the recovery for ECRC cost recovery established by Order No. PEC-94-0044-FOF-EI in that:

a) All expenditures will be prudently incurred after April 13, 1993;

b) 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 which rates are based; and

c) None of the expenditures are being recovered through some other cost recovery mechanism or through base rates.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

GARRY MILLER

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 150007-EI

AUGUST 31, 2015

Q. Please state your name and business address.

A. My name is Garry Miller. My business address is 400 South Tryon Street, Charlotte, NC 28202.

Q. Have you previously filed testimony before this Commission in Docket No. 150007-EI?

A: Yes. I provided direct testimony on July 31, 2015.

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 an update on Duke Energy Florida LLC's ("DEF" or "Company") proposed compliance activities and related 2016 estimated costs associated with the Coal Combustion Residual ("CCR") Rule for which the Company seeks recovery under the Environmental Cost Recovery Clause ("ECRC").

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 22 of 22 – Coal Combustion Residual Rule

Q. Has DEF's 2015 expected CCR Rule compliance strategy changed?

A: Yes. Expected CCR compliance activities associated with the temporary gypsum pad and additional capital costs to comply with vegetation management requirements as explained in my July 31, 2015 direct testimony in the instant Docket have changed.

Efforts to address fugitive dust mitigation at the CCR gypsum stack-out continue to be underway. At completion , the Crystal River ("CR") temporary gypsum pad will not be subject to CCR compliance requirements as a CCR landfill. DEF estimated $1.5M of capital expenditures in 2015 for the addition of a permanent dust control system. Based on further analysis, DEF will be unable to complete the permanent solution by October 19, 2015. DEF will employ a temporary dust mitigation solution while the permanent solution is constructed. The permanent solution is expected to be in-service by October 2016. DEF estimates O&M costs for a temporary fugitive dust mitigation system of $75k and $250k in 2015 and 2016, respectively. Total estimated 2016 capital costs for a permanent dust control system at the CCR gypsum stack-out by October 2016 are $2.1 million. Additionally, DEF has determined that vegetation management compliance can be achieved without spending the $100k of capital included in the July 31, 2015 Filing.

Q: What are the CCR rule compliance activities and associated costs for which DEF is seeking recovery in 2016?

A: Ash Landfill

Various maintenance and repair work is required for the CR ash landfill such as fixing ruts and animal burrows, vegetation management, erosion repairs, and other activities to ensure compliance with the CCR rule. Total estimated O&M costs are $150k.

Temporary Gypsum Pad

Total estimated costs for temporary and permanent dust control systems are $325k in O&M and $2.1M in capital, as explained above. In addition, $875k of O&M costs are estimated to dredge the gypsum basin. DEF also expects to spend $100k in O&M costs for ash/gypsum handling and disposal to comply with CCR rule requirements.

Flue Gas Desulfurization (“FGD”) Blowdown Ponds

As addressed in my July 31, 2015 direct testimony, groundwater monitoring is required for the FGD blowdown ponds along with weekly assessments based on the results of liner assessments required by the rule. DEF estimates $1.8M of capital costs for engineering, including sampling, analysis, and reporting, and drilling wells.

Emergency Action Plan ("EAP")

No 2016 costs are projected for development of an EAP.

Vegetation Management & Inspection Work

Total estimated O&M costs for increased vegetation management at the CR ash landfill, percolation ponds and FGD Blowdown Ponds are $200k. Incremental O&M costs for system owner to perform CCR inspections and coordinate CCR compliance activities and requirements are $154k.

Q. Are there any other CCR rule compliance activities and costs for which DEF expects to seek recovery in 2016?

A. DEF continues to evaluate the CCR rule to determine operating and cost impacts, and expects to incur costs in 2016 and beyond. However, the full extent of compliance activities and associated costs cannot be determined until further analysis and assessments of the CCR rule are complete. As these analyses and assessments are completed and additional compliance activities and costs become known, DEF will update the Commission and provide the costs for recovery, as appropriate, in later ECRC filings.

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. 150007-EI

July 31, 2015

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. 150007-EI?

A: Yes, I provided direct testimony on April 1, 2015.

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 2015 actual/estimated cost projections and original 2015 cost projections for environmental compliance costs associated with FPSC-approved environmental programs under my responsibility. These programs include the CAIR/CAMR Crystal River (CR) Program (Project 7.4) and Mercury & Air Toxics Standards (MATS) – Crystal River 1&2 Program (Project 17.2).

Q. How do actual/estimated O&M project expenditures compare with original projections for the CAIR/CAMR Crystal River (CR) Program (Project 7.4) for the period January 2015 through December 2015?

A. O&M expenditures are expected to be $661k higher than originally projected. This variance is primarily driven by a $710k decrease in CAIR/CAMR CR Project 7.4 – Base offset by a $1.4 million increase in CAIR/CAMR CR Project 7.4 – Energy.

Q. Please explain the variance between actual/estimated O&M project expenditures and original projections for the CAIR/CAMR CR Program (Project 7.4 – Base) for the period January 2015 through December 2015.

A. The $710k decrease is due to lower than projected base routine project costs.

Q. Please explain the variance between the actual/estimated O&M project expenditures and original projections for the CAIR/CAMR Crystal River Program (Project 7.4 – Energy) for the period January 2015 through December 2015.

A. The $1.4 million increase is primarily attributable to a $2.7 million increase in ammonia expense due to a higher ammonia price and a $1.4 million higher hydrated lime expense driven by a switch in product type to comply with sulfur trioxide (SO3) emissions air permit limits, partially offset by $1.3 million in lower limestone expense due to less consumption and $1.2 million in lower gypsum expense as a result of lower disposal volume and reduced sales expense.

Q. **Please explain the variances between the actual/estimated capital project expenditures and original projections for the CAIR/CAMR Crystal River Program (Project 7.4) for the period January 2015 through December 2015?**

A. Capital expenditures are expected to be $124k higher than originally projected primarily due to a shift in spending from 2014 to 2015 in order to align with the City of Crystal River reclaimed water reuse project timeline.

Q: **Please explain the variance between actual/estimated capital project expenditures and original projections for the MATS – CR 1&2 Program (Project 17.2) for the period January 2015 through December 2015.**

A: Capital expenditures are expected to be $4.2 million higher than originally projected due to an additional project related to the Unit 1 electrostatic precipitator (ESP). Performance testing with western bituminous coals in October 2014 revealed higher than expected duct opacity and particulate matter (PM) emissions from Unit 1. Following unit inspections and extensive modeling, a decision was made in November 2014 to replace and upgrade the Unit 1 ESP power supplies and internal components in order to achieve PM emission targets considered in the original compliance study. This work was implemented during the spring 2015 outage, and further testing with western coals is planned for summer 2015 to assess the new performance levels.

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

A: The MATS-CR1&2 Program is on schedule to meet the targeted in-service date of April 2016 as stated in Order PSC-14-0173-PAA-EI. Total estimated costs are expected to increase from $28 million to $33 million primarily as a result of the Unit 1 ESP project referenced in the variance explanation above.

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. 150007-EI

April 1, 2015

Q. Please state your name and business address.

A. My name is Jeffrey Swartz. My business address is 8202 W. Venable St, Crystal River, FL 34429.

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

A. I am employed by Duke Energy Florida (DEF or the Company) as Vice President –Fossil/Hydro Operations Florida.

Q. What are your responsibilities in that position?

A. As Vice President of DEF's Fossil/Hydro organization, my responsibilities include overall leadership and strategic direction of DEF's power generation fleet. My responsibilities include strategic and tactical planning to operate and maintain DEF's non-nuclear generation fleet; generation fleet project and addition recommendations; major maintenance programs; outage and project management; generation facilities retirement; asset allocation; workforce planning and staffing; organizational alignment and design; continuous business improvement; retention and inclusion; succession planning; and oversight of numerous employees and hundreds of millions of dollars in assets and capital and O&M 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 in 1985. I have 14 years of power plant and production experience at Duke Energy in various managerial and executive positions in fossil steam, combustion turbine and nuclear plant operations. I also managed new construction and O&M projects. I have extensive contract negotiation and management experience. My prior experience includes nuclear engineering and operations experience in the United States Navy, and project management, engineering, supervisory and management oversight 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 actual/estimated project expenditures for environmental compliance costs associated with DEF's Integrated Clean Air Compliance Program (Project 7.4) and Mercury & Air Toxics Standards (MATS) – CR 1&2 (Project 17.2) for the period January 2014 - December 2014.

Q. How do actual O&M expenditures for January 2014 - December 2014 compare with DEF's actual/estimated projections for the Clean Air Interstate Rule/Clean Air Mercury Rule (CAIR/CAMR) Crystal River Program (Project 7.4)?

A. The CAIR/CAMR Crystal River O&M variance is $56,104 or .2% higher than projected. This variance is primarily attributable to $115,741 lower than expected costs for CAIR Crystal River Project 7.4 – Base and $171,498 higher than expected costs for CAIR Crystal River Project 7.4 - Energy.

Q: Please explain the variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Base for January 2014 - December 2014?

A: O&M costs for CAIR Crystal River Project – Base were $115,741 or 1% lower than projected. This variance is primarily driven by a $270 thousand decrease in labor due to lower burden rates offset by a $198 thousand increase due to a change in strategy to comply with FDEP wastewater permit requirements and $52 thousand of expected maintenance work not completed in 2014.

Q. Please explain the variance between actual project expenditures and the actual/estimated projections for the CAIR Crystal River Project – Energy for the period January 2014 - December 2014?

A. O&M costs for reagents and by-products were $171,498 or 1% higher than projected. This variance is primarily attributable to $1.5 million higher ammonia expense due to a higher than projected ammonia price; $680 thousand higher hydrated lime expenses due to more consumption than expected; $830 thousand lower gypsum expense as a result of less than expected disposal volume and reduced sales expense; and $1.1 million lower limestone expense driven by milder weather and unscheduled outages.

Q. How did actual O&M expenditures for January 2014 - December 2014 compare with DEF's actual/estimated projections for the MATS – CR 1&2 Project (Project 17.2)?

A. The MATS – CR 1&2 O&M variance is $1 million or 18% lower than projected due to a reduced scope of work in 2014 for the Unit 1 Flue Gas Redistribution and MATS Related Plant Testing projects. This work will be completed in the second quarter of 2015.

Q. How did actual capital expenditures for January 2014 - December 2014 compare with DEF's actual/estimated projections for the MATS – CR 1&2 Project (Project 17.2)?

A. The MATS – CR 1&2 capital variance is $523,175 or 8% higher than projected as a result of materials purchased for a Unit 1 electrostatic precipitator project. Due to vendor lead times, these materials were ordered in December 2014 for installation in 2nd Quarter 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. 150007-EI

April 1, 2015

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 Duke Energy Florida (DEF or the Company) as Director Environmental Field Support – Florida.

Q. What are your responsibilities in that position?

A. Currently, my responsibilities include managing the work of environmental professionals who are responsible for environmental, technical, and regulatory support during the development and implementation of environmental compliance strategies for regulated power generation facilities and electrical transmission and distribution 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 in my role as the Director Environmental Field Support – FL.

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 actual/estimated project expenditures for environmental compliance costs associated with DEF's Pipeline Integrity Management (PIM) Program (Project 3), Cooling Water Intake – 316(b) (Project 6 & 6a), Clean Air Interstate Rule/Clean Air Mercury Rule (CAIR/CAMR) – Peaking (Project 7.2), Arsenic Groundwater Standard (Project 8), and Mercury & Air Toxics Standards (MATS) – Crystal River Units 4 & 5 (CR 4&5) (Project 17) for the period

January 2014 - December 2014. I also provide an update of the Cross State Air Pollution Rule (CSAPR) and its impact on DEF's emission allowances. 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 2014 - December 2014 compare with DEF's actual/estimated projections for the PIM Project (Project 3)?

A. The PIM O&M variance is $136,374 or 33% lower than projected due to the Florida Department of Transportation (FDOT) deferment of the 2014 pipeline protection project at Gandy Blvd until 2015.

Q. How did actual O&M expenditures for January 2014 - December 2014 compare with DEF's actual/estimated projections for the Cooling Water Intake - 316(b)Project (Project 6 & 6a)?

A. The Cooling Water Intake - 316(b) variance is $28,570 or 26% lower than projected due to the method used to allocate costs to analyze 316(b) compliance strategies at each affected Duke generating site. Duke intends to implement a consistent 316(b) compliance approach across its entire fleet of regulated units.

Q. How did actual O&M expenditures for January 2014 - December 2014 compare with DEF's actual/estimated projections for the CAIR/CAMR – Peaking Project (Project 7.2)?

A: The CAIR/CAMR – Peaking variance is $10,061 or 22% lower than projected due to December 2014 invoices inadvertently charged to non-ECRC projects. This error was corrected in January 2015.

Q. How did actual O&M expenditures for January 2014 - December 2014 compare with DEF's actual/estimated projections for the Arsenic Groundwater Standard Project (Project 8)?

A. The Arsenic Groundwater Monitoring variance is $1,969 or 22% higher than projected due to consultant costs to evaluate monitoring data and prepare a report documenting the evaluation in compliance with the FDEP Consent Order No. 09-3463C. The Consent Order was issued by the FDEP for exceedance of the arsenic groundwater limit when EPA lowered the arsenic maximum contaminant level from 50 ppb to 10 ppb.

Q. How did actual O&M expenditures for January 2014 - December 2014 compare with DEF's actual/estimated projections for the MATS – CR 4&5 Project (Project 17)?

A. The MATS – CR 4&5 O&M variance is $81,039 or 31% higher than projected due to an increase in scope of the Mercury Characterization Study and completion in December 2014 instead of January 2015.

Q. How did actual capital expenditures for January 2014 - December 2014 compare with DEF's actual/estimated projections for the MATS – CR 4&5 Project (Project 17)?

A. The MATS – CR 4&5 capital variance is $106,923 or 28% lower than projected primarily due to lower than expected spend on the installation of particulate matter (PM) continuous emission monitoring systems (CEMS). Additionally, PM CEMS correlation testing was delayed from November 2014 to March 2015 to allow for sufficient communication with the FDEP regarding regulatory requirements associated with the testing.

Q. In Order No. PSC-10-0683-FOF-EI issued in Docket No. 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 CR 4&5 have enabled

DEF to comply with Clean Air Interstate Rule (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 the analyses performed to date are included in my Exhibit No. __ (PQW-1).

Q. What is the history and status of CSAPR?

A. The EPA adopted the CSAPR to replace the CAIR by publication in the Federal Register in August 2011. The CSAPR establishes state-level annual and seasonal SO_2 and NOx emissions allowance requirements that were effective January 1, 2012. Under CSAPR, the State of Florida is no longer required to comply with annual emission requirements, only ozone seasonal limits. In Order No. PSC-11-0553-FOF-EI, the Commission established a regulatory asset to allow DEF to recover the costs of its remaining CAIR NOx allowance inventory over a three (3) year amortization period. However, on December 30, 2011, the D.C. Circuit Court of Appeals stayed the CSAPR leaving the CAIR in effect until it completed its review of CSAPR. Consequently, DEF continued to maintain its NOx allowance inventory in order to comply with the CAIR. In August 2012, the D.C. Circuit Court of Appeals vacated the CSAPR and directed the EPA to continue administrating the CAIR program. The EPA subsequently appealed this decision to the U.S. Supreme Court. In April 2014, the U.S. Supreme Court overturned the D.C. Circuit Court's ruling and remanded the case back to the lower court for further action. In June 2014, the EPA requested that the court lift the CSAPR stay and allow it to be implemented under a revised schedule. This request was granted in October 2014 and the CSAPR went into effect on January 1, 2015 replacing the CAIR program. Additional CSAPR litigation is ongoing. Oral argument was held on February 25, 2015, before the D.C. Circuit Court.

Q. When does compliance with the CSAPR become effective for Florida?

A. The CSAPR replaces the CAIR starting January 1, 2015. The effective compliance date for Florida is May 1, 2015, the beginning of the ozone season.

Q. Can emission allowances previously issued to DEF under CAIR and/or the Acid Rain Program be used to comply with the CSAPR?

A. No. The Acid Rain Program is a separate statutory program with different compliance requirements, and the CSAPR is a replacement for the CAIR program, meaning that the Acid Rain Program continues in effect. As of January 1, 2015, the NOx emission allowances under the CAIR have no value; however, DEF will continue to use its SO_2 emission allowances to comply with the Acid Rain Program.

Q. Are the number of emission allowances allocated to Florida's emission units under the CSAPR similar to the CAIR program?

A. No. The allowances provided to Florida's emission units under the CSAPR are about one-half of the amounts previously allocated under the CAIR. This is not expected to cause significant issues meeting required compliance levels as emissions levels in the state have continued to decrease over the past several years.

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. 150007-EI

July 31, 2015

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. 150007-EI?

A: Yes, I provided direct testimony on April 1, 2015.

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 2015 actual/estimated cost projections and original 2015 cost projections for environmental compliance costs associated with FPSC-approved programs under my responsibility. These programs include the Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a), Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2), 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), Sea Turtle Coastal Street Lighting Program (Project 9), 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 2015 through December 2015.

Q: Please explain the variance between actual/estimated project expenditures and original projections for Substation Environmental Investigation, Remediation and Pollution Prevention Program (Projects 1 & 1a) for the period January 2015 through December 2015.

A: O&M expenditures for substation system program are estimated to be $405k lower than originally projected. This variance is in part due to remediation work delays at the Consolidated Rock, Holder and Kenneth City substations. Consolidated Rock remediation is delayed due to restricted access by the property owner. Work will begin once this issue is resolved. Holder remediation is postponed until 2016 when breaker replacement work can be completed. Kenneth City remediation is rescheduled to 2016 when the existing control house is demolished and rebuilt.

Q: Please explain the variance between actual/estimated project expenditures and original projections for Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2) for the period January 2015 through December 2015.

A: O&M expenditures for the distribution system program are estimated to be $42k or 265% higher than originally projected due to costs to remove additional impacted soil at the three remaining sites. Original projections were based on performing groundwater monitoring at two of these sites; however, groundwater concentrations at these sites increased or did not improve over the past year. Consequently, DEF stopped groundwater monitoring and developed plans to remove additional impacted soil underneath building foundations and storm water infrastructure.

Q: Please explain the variance between actual/estimated project expenditures and original projections for Cooling Water Intake – 316(b) (Project 6 & 6a) for the period January 2015 through December 2015.

A: O&M expenditures for Cooling Water Intake – 316(b) are expected to be $43k or 14% lower than originally projected as methods used to allocate costs to analyze 316(b) compliance strategies at each affected Duke Energy generating site were adjusted to reflect present configurations and operations. Duke Energy intends to implement a consistent 316(b) approach across its entire fleet of regulated units which focuses on full compliance with applicable 316(b) requirements through the development of facility specific strategic plans. These plans will include all applicable submittal requirements; targeted entrainment and impingement compliance options; compliance schedules; identification of decision and agency milestones; risk assessments; and implementation plans with key activities and timelines.

Q: Please explain the variance between actual/estimated project expenditures and original projections for Arsenic Groundwater Standard (Project 8) for the period January 2015 through December 2015.

A: O&M expenditures for Arsenic Groundwater Standard are expected to be $23k or 144% higher than originally projected due to consultant costs to evaluate the source of arsenic exceedances and issue a summary report in compliance with FDEP Consent Order No. 09-3463C executed on November 21, 2011. The Consent Order was issued by the FDEP for exceedance of the arsenic groundwater limit when the EPA lowered the arsenic maximum containment level from 50 ppb to 10 ppb.

Q: Please explain the variance between actual/estimated project expenditures and original projections for Sea Turtle – Coastal Street Lighting Program (Project 9) for the period January 2015 through December 2015.

A: Capital expenditures for the Sea Turtle – Coastal Street Lighting Program are estimated to be $3k or 92% lower than originally projected. No new street lighting has been required in Franklin County, the City of Mexico Beach in Bay County, or Gulf County as DEF is in compliance with sea turtle ordinances. Also, the Don Cesar lighting project is delayed from 2014 until late 4th quarter 2015 due to scheduling conflicts.

Q: Please explain the variance between actual/estimated project expenditures and original projections for NPDES (Project 16) O&M for the period January 2015 through December 2015.

A: O&M expenditures for NPDES are expected to be $54k or 20% lower than originally projected due to lower than expected 316(a) thermal study costs at the Anclote and Bartow stations.

Q: Please explain the variance between actual/estimated project expenditures and original projections for NPDES (Project 16) capital for the period January 2015 through December 2015.

A: Capital expenditures for NPDES project are expected to be $86k or 275% lower than originally projected primarily due to a vendor reimbursement payment.

Q: Please explain the variance between actual/estimated project expenditures and original projections for MATS – CR4&5 (Project 17) O&M for the period January 2015 through December 2015.

A: O&M expenditures for MATS – Crystal River Units 4&5 (CR4&5) are expected to be $153k higher than originally projected. This variance is primarily driven by the addition of a temporary chemical injection system to control mercury emissions, and the cancellation of preliminary engineering for a fuel additive system to improve mercury oxidation. This change in compliance strategy resulted from a mercury characterization study performed in December 2014 that identified mercury re-emission as the root cause of elevated emissions in 2014.

Q: Please explain the variance between actual/estimated project expenditures and original projections for MATS – CR4&5 (Project 17) capital for the period January 2015 through December 2015.

A: Capital expenditures for MATS – CR4&5 are expected to be $1.3 million higher than originally projected. This variance is driven by the installation of continuous emission monitoring systems (CEMS) for mercury monitoring, compliance demonstration and feedback to the re-emission control system. DEF determined that continuous monitoring was necessary following elevated emissions in the second half of 2014 and a characterization study completed in December 2014.

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 (FGD) 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 had 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) 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: The 316(b) rule became effective October 15, 2014 to minimize impingement and entrainment of fish and aquatic life drawn into cooling systems at power plants and factories. There are seven impingement options. Entrainment compliance is site specific (mesh screen or closed-cycle cooling). Litigation of the 316(b) rule is in process.

The regulation primarily applies to facilities that commenced construction on or before 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: Existing Units – The EPA plans to regulate CO_2 emissions from existing fossil fuel-fired units under the President's Climate Action Plan announced in June 2013. The EPA published proposed guidelines on June 18, 2014. The comment period ended December 1, 2014. The EPA is targeting mid-summer 2015 for a final rule.

Murray Energy and other parties challenged the EPA's authority to implement the proposed Clean Power Plan under the Clean Air Act. On June 9, 2015, the D.C. Circuit Court of Appeals dismissed the challenge on the grounds that the rule is not yet final. As a result, the EPA can proceed to finalize the rule, which is expected in August. The rule is currently under review by the Office of Management and Budget.

New Units – The EPA proposal establishes stringent CO_2 limits on new coal-fired units effectively eliminating them. The EPA expects to issue a final rule this summer.

DEF does not expect to incur ECRC costs in 2015 related to Carbon Regulations.

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

A: On October 23, 2014, the D.C. Circuit Court lifted the stay of the CSAPR which establishes state-level annual and seasonal SO_2 and NO_x emission allowance requirements. The CSAPR replaced the Clean Air Interstate Rule (CAIR) on January 1, 2015. Under the CSAPR, the State of Florida is no longer required to comply with annual emission requirements, only ozone seasonal limits. The CSAPR requirements took effect in Florida on May 1, 2015, the beginning of the ozone season.

As explained in my April 1, 2015 direct testimony, NO_x emission allowances under CAIR have no value; however, DEF will continue to use its SO_2 emission allowances to comply with the Acid Rain Program. As explained in Mr. Geoff Foster's April 1, 2015 direct testimony, DEF is treating its unused NO_x costs as a regulatory asset amortizing it over three years beginning January 1, 2015 through December 31, 2017, with a return on the unamortized investment, consistent with Order no. PSC-11-0553-FOF-EI.

Q: Please provide an update on the Coal Combustion Residual (CCR) Rule.

A: As explained further in the direct testimony of Mr. Garry Miller, the CCR rule was published in the Federal Register on April 17, 2015 and is effective on October 17, 2015. The rule has specific compliance impacts on the ash landfill, gypsum storage pad and FGD lined blowdown ponds at the Crystal River site. Although the full range of compliance activities and costs are still being evaluated, DEF's planned 2015 compliance activities and their associated cost projections are provided by Mr. Miller.

Q: Please provide an update on the Mercury and Air Toxics Standards (MATS) Rule.

A: On June 29, 2015, the U. S. Supreme Court ruled that it was unreasonable for EPA to refuse to consider costs in determining that regulation of electric generating units was "appropriate and necessary" under Clean Air Act section 112. The Court remanded the case back to the D.C. Circuit Court of Appeals for further proceedings consistent with its opinion. The MATS rule will remain in effect pending additional action by the D.C. Circuit; therefore, a decision is not expected to impact the implementation of DEF's MATS compliance plan until further proceedings are completed.

Q: Please provide an update on the National Ambient Air Quality Standards (NAAQS).

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 District 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. The EPA has proposed to revise the current standard of 75 parts per billion (ppb) to within a range of 65 to 70 ppb.

Q: Please provide an update on the Steam Effluent Limitation Guidelines (ELG).

A: On April 8, 2014, the EPA acknowledged the need to closely coordinate this rule, which regulates waste streams from power plants, with the CCR rule, which regulates landfills and ash basins. The deadline for the EPA to issue the final Steam Effluent Limitations Guidelines was extended to September 30, 2015.

Q: Please provide an update on the Waters of the United States (WOTUS) Rule.

A: On May 27, 2015, the EPA issued a final rule that defines the scope of waters protected under the Clean Water Act (CWA). The rule was published in the

Federal Register on June 29, 2015. Among other things, the WOTUS Rule clarifies the characteristics of water streams, wetlands and other waters to which the CWA applies. DEF is in the process of analyzing the new rule requirements and potential impacts and compliance options at its operational sites, and expects to incur compliance costs in 2015. However, the full extent of compliance activities and associated costs cannot be determined as DEF has not had sufficient opportunity to determine the rule's impacts on affected facilities and compliance alternatives. DEF will provide an update on its WOTUS program in the 2016 Projection Filing, and DEF will include any compliance costs incurred in 2015 in the 2015 Final True-Up balance.

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, LLC.

DOCKET NO. 150007-EI

August 31, 2015

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. 150007-EI?

A: Yes. I provided direct testimony on April 1, 2015 and July 31, 2015.

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 2016 for Duke Energy Florida LLC's ("DEF" or "Company") Substation Environmental Investigation, Remediation and Pollution Prevention

Program (Project 1 & 1a), Distribution Environmental Investigation, Remediation and Pollution Prevention Program (Project 2), Pipeline Integrity Management ("PIM") Program (Project 3), Above Ground Storage Tanks ("AST") Program (Project 4), Phase II Cooling Water Intake 316(b) Program (Project 6), CAIR/CAMR Continuous Mercury Monitoring System ("CMMS") Program (Projects 7.2 & 7.3), Best Available Retrofit Technology ("BART") Program (Project 7.5), Arsenic Groundwater Standard Program (Project 8), Sea Turtle – Coastal Street Lighting Program (Project 9), Underground Storage Tanks ("UST") Program (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge Permanent Compliance (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 1 of 22 – Substation Environmental Investigation, Remediation and Pollution Prevention Program

- 42-5P page 2 of 22 - Distribution System Environmental Investigation, Remediation and Pollution Prevention Program
- 42-5P page 3 of 22 – PIM
- 42-5P page 4 of 22 - AST
- 42-5P page 6 of 22 - Phase II Cooling Water Intake
- 42-5P page 7 of 22 – Clean Air Interstate Rule ("CAIR")
- 42-5P page 8 of 22 – BART
- 42-5P page 9 of 22 - Arsenic Groundwater Standard
- 42-5P page 10 of 22 – Sea Turtle – Coastal Street Lighting Program
- 42-5P page 11 of 22 - UST
- 42-5P page 12 of 22 - Modular Cooling Towers
- 42-5P page 13 of 22 - Thermal Discharge Permanent Cooling Tower
- 42-5P page 14 of 22 - Greenhouse Gas Inventory and Reporting
- 42-5P page 15 of 22 - Mercury TMDL
- 42-5P page 16 of 22 - HAPs ICR
- 42-5P page 17 of 22 - Effluent Limitation Guidelines ICR Program
- 42-5P page 18 of 22 - NPDES
- 42-5P page 19 of 22 - MATS – CR4&5

Q. What costs does DEF expect to incur in 2016 for the Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a)?

A. DEF estimates $1.1 million of O&M costs at 19 sites for the Substation Environmental Investigation, Remediation and Pollution Prevention Program. These costs also include institutional controls and report writing activities for various substations.

Q. What costs does DEF expect to incur in 2016 for the Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2)?

A. DEF estimates $3k of O&M costs to complete remediation of one remaining site for the Distribution System Investigation, Remediation, and Pollution Prevention Program (Project 2).

Q. What costs does DEF expect to incur in 2016 for the PIM Program (Project 3)?

A. DEF estimates $696k of O&M costs for the Pipeline Integrity Management Program to comply with 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 2016 for the AST Program (Project 4)?

A. DEF does not expect any costs. The Florida Department of Environmental Protection ("FDEP") is expected to issue amendments to its AST rule. DEF continues to engage with the FDEP in the rulemaking process, but it is unclear what potential impacts the proposed rule amendments will have on DEF's operational sites, and to what extent compliance options will be available and ultimately pursued. The FDEP expects to conduct a public workshop later this year, and final AST rule revisions could be adopted by the Summer of 2016. DEF cannot estimate its compliance costs until the AST revisions are final. DEF will provide the Commission with its estimated compliance costs in its next available filing once the rule is final.

Q. What costs does DEF expect to incur in 2016 for the Phase II Cooling Water Intake Program (Project 6)?

A. DEF estimates $440k of O&M costs for the Phase II Cooling Water Intake Program to evaluate compliance with the 316(b) rule.

Q. What costs does DEF expect to incur in 2016 for the CAIR/CAMR Program (Project 7.2)?

A. DEF estimates $134k of O&M costs 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.

Q: What costs does DEF expect to incur in 2016 for the BART Program (Project 7.5)?

A: DEF does not expect any costs.

Q. What costs does DEF expect to incur in 2016 for the Arsenic Groundwater Standard Program (Project 8)?

A. At present, DEF does not expect to incur any costs; however the regulatory path for the satisfactory conclusion of the Arsenic Groundwater Standard Program is still being negotiated with the FDEP. Any final agreements may include future additional work or components that are unknown at this time but may result in compliance costs in 2016.

Q. What costs does DEF expect to incur in 2016 for the Sea Turtle – Coastal Street Lighting Program (Project 9)?

A. DEF estimates $450 and $750 in O&M and capital costs, 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 costs does DEF expect to incur in 2016 for the Underground Storage Tanks Program (Project 10)?

A. DEF does not expect any costs. However, the FDEP continues to evaluate the EPA's federal UST revisions to ensure consistency with state and federal rules. It is unclear how long the FDEP will have its amended UST rule on hold. DEF cannot estimate its compliance costs until the UST revisions are final. DEF will provide the Commission with its estimated compliance costs in its next available filing once the rule is final.

Q. What costs does DEF expect to incur in 2016 for the Modular Cooling Tower (Project 11)?

A. DEF does not expect any costs.

Q. What costs does DEF expect to incur in 2016 for the Thermal Discharge Permanent Cooling Tower (Project 11.1)?

A. DEF does not expect any costs.

Q. What costs does DEF expect to incur in 2016 for the Greenhouse Gas Inventory and Reporting Program (Project 12)?

A. DEF does not expect any costs.

Q. What costs does DEF expect to incur in 2016 for the Mercury TMDL Program (Project 13)?

A. DEF does not expect any costs.

Q. What costs does DEF expect to incur in 2016 in for the HAPs ICR Program (Project No. 14)?

A. DEF does not expect any costs.

Q. What costs does DEF expect to incur in 2016 for the Effluent Limitation Guidelines ICR Program (Project No. 15)?

A. DEF does not expect any costs.

Q. What costs does DEF expect to incur in 2016 for the NPDES Program (Project No. 16)?

A. DEF estimates $60k of O&M costs for whole effluent toxicity (“WET”) testing at DEF stations with NPDES permits..

Q. What O&M costs does DEF expect to incur in 2016 for the MATS Program – CR4&5 (Project No. 17)?

A. DEF estimates O&M costs of approximately $529k for CR4&5 MATS compliance. This estimate includes contractor costs for maintenance and quality assurance of Appendix K sorbent trap monitoring systems, particulate matter (“PM”) continuous emissions monitoring systems (“CEMS”), and mercury CEMS, as well as chemical costs for the mercury re-emission control systems.

Q. What capital costs does DEF expect to incur in 2016 for the MATS Program – CR4&5 (Project No. 17)?

A. DEF does not expect any expenditures in 2016.

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

A. Yes. DEF seeks approval of its Coal Combustion Residual Program as discussed in my July 31, 2015 direct testimony, and direct testimonies of Geoff Foster and Garry Miller in this Docket.

Q. Please provide an update on the EPA's carbon dioxide regulations.

A: Existing Units – The EPA issued its final "Clean Power Plan" emission guidelines on August 3, 2015. The final rule contains significant changes from the proposed version, including a less-stringent emissions goal for Florida and a change in the start of the interim compliance period to 2022. In addition, the EPA issued a proposed federal implementation plan (FIP) for the Clean Power Plan, which EPA would impose on states that do not submit sufficient state plans. Initial state plans are due September 6, 2016, and states may request a 2-year extension to September 2018.

Murray Energy and other parties challenged the EPA's authority to implement the proposed Clean Power Plan under the Clean Air Act. On June 9, 2015, the D.C. Circuit Court of Appeals dismissed the challenge on the grounds that the rule was not yet final. The challenge is likely to be re-filed after the final Clean Power Plan is published in the *Federal Register*.

New Units – The final New Source Performance Standards (NSPS) for new, modified and reconstructed units were issued August 3, 2015. They contain a less-restrictive emission limit for coal-fired boilers, increasing to 1,400 lbs.

CO_2/MWh from the proposed level of 1,100 lbs. CO_2/MWh. The EPA assumed a lower level of carbon capture and storage (CCS) for the revised limit. In addition, the EPA asserts that the limit can be achieved without CCS by co-firing with natural gas. The final limit of 1,000 lbs. CO_2/MWh for natural gas-fired combustion turbines did not change from the proposal.

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. 150007-EI

April 1, 2015

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 or the Company) as 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 24 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 actual/estimated project expenditures for environmental compliance costs associated with DEF's Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Project 1 & 1a) for the period January 2014 - December 2014.

Q. How did actual O&M expenditures for January 2014 - December 2014 compare with DEF's actual/estimated projections for the Substation System Program (Project 1 & 1a)?

A. The Substation System Program variance is $897,068 or 31% lower than projected. This variance is primarily due to delays at Consolidated Rock, Holder, and Windermere transmission substations, and lower than estimated costs for remediation work at Central Florida. Consolidated Rock remediation is delayed due to restricted access by the property owner. Work will begin once this issue is resolved. Holder remediation is deferred to 2016 until breaker replacement work scheduled for October 2015 is complete. At Windermere, some regrading was anticipated in 2014, however, ongoing construction at that substation continues. This construction work is scheduled for completion at the end of March 2015 at which time remediation can resume.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150007-EI
FILED: 04/01/15

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 18 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 actual true-up amount for the Environmental Cost Recovery Clause ("Environmental Clause") and the calculations associated with the environmental compliance activities for the January 2014 through December 2014 period.

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

A. Yes. Exhibit No. _____ (PAR-1) consists of nine documents prepared under my direction and supervision.

- Form 42-1A, Document No. 1, provides the final true-up for the January 2014 through December 2014 period;
- Form 42-2A, Document No. 2, provides the detailed

calculation of the actual true-up for the period;

- Form 42-3A, Document No. 3, shows the interest provision calculation for the period;
- Form 42-4A, Document No. 4, provides the variances between actual and actual/estimated costs for O&M activities;
- Form 42-5A, Document No. 5, provides a summary of actual monthly O&M activity costs for the period;
- Form 42-6A, Document No. 6, provides the variances between actual and actual/estimated costs for capital investment projects;
- Form 42-7A, Document No. 7, presents a summary of actual monthly costs for capital investment projects for the period;
- Form 42-8A, Document No. 8, pages 1 through 25, illustrates the calculation of depreciation expenses and return on capital investment for each project recovered through the Environmental Clause.
- Form 42-9A, Document No. 9, details Tampa Electric's revenue requirement rate of return for capital projects recovered through the Environmental Clause.

Q. What is the source of the data presented in your testimony and exhibits?

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

Q. What is the final true-up amount for the Environmental Clause for the period January 2014 through December 2014?

A. The final true-up amount for the Environmental Clause for the period January 2014 through December 2014 is an under-recovery of $3,915,636. The actual environmental cost over-recovery, including interest, is $3,020,040 for the period January 2014 through December 2014, as identified in Form 42-1A. This amount, less the $6,935,676 over-recovery approved in Commission Order No. PSC-14-0643-FOF-EI, issued November 4, 2014, in Docket No. 140007-EI, results in a final under-recovery of $3,915,636, as shown on Form 42-1A. This under-recovery amount will be applied in the calculation of the environmental cost recovery factors for the period January 2016 through December 2016.

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

A. All costs listed in Forms 42-4A through 42-8A for which Tampa Electric is seeking recovery are incurred for environmental compliance projects approved by the Commission.

Q. Did Tampa Electric include costs in its 2014 final Environmental Clause true-up filing for any environmental projects that were not anticipated and included in its 2014 factors?

A. No.

Q. How do actual expenditures for the January 2014 through December 2014 period compare with Tampa Electric's actual/estimated projections as presented in previous testimony and exhibits?

A. As shown on Form 42-4A, total costs for O&M activities are $1,236,605, or 4.5 percent greater than the actual/estimated projection costs. Form 42-6A shows the total capital investment costs are $294,929, or 0.5 percent less than the actual/estimated projection costs.

Additional information regarding variances that exceed $50,000 is provided below.

O&M Project Variances

- **Big Bend Unit 3 Flue Gas Desulfurization Integration:** The Big Bend Unit 3 Flue Gas Desulfurization Integration project variance is $500,835, or 9.8 percent greater than projected, primarily driven by increases in the price for consumables.
- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is $330,062, or 12.5 percent greater than projected. This variance is due to an increase in ammonia flow to decrease ammonium bisulfate build-up in the stackers.
- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is $372,047, or 14.3 percent greater than projected. The variance is due to an increase in ammonia flow to decrease ammonium bisulfate build-up in the stackers.
- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is $131,157, or 15.4 percent greater than projected. This variance is due to an increase in ammonia flow to decrease ammonium bisulfate build-up in the stackers.

- **Mercury Air Toxics Standards:** The Mercury Air Toxics Standards ("MATS") project variance is $61,294, or 53.3 percent less than originally projected. The projected costs included equipment that was to be purchased in 2014; however, the purchase was delayed until 2015. Additionally, the projected costs include contractor labor expenses; however, the company was able to utilize internal labor rather than contractor labor. Internal labor costs are not recovered through the Environmental Clause.
- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility project variance is $273,358, or 34.4 percent less than projected. The facility in-service date was projected to be October 2014 but actually occurred in November 2014. Accordingly, cost recovery of O&M expenses was less than projected for 2014.

Capital Project Variances

- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility project variance is $271,867, or 48.6 percent less than projected. The facility in-service date was projected to be October 2014 but actually occurred in November 2014. Therefore, cost recovery of the project return on investment and depreciation were delayed, resulting in lower costs than projected for 2014.

Q. Does this conclude your testimony?

A. Yes, it does.

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. I have accumulated 18 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 2015 through December 2015 actual/estimated true-up amount to be refunded or recovered through the Environmental Cost Recovery Clause ("ECRC") during the period January 2016 through December 2016. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2015, 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 2016 through December 2016.

Q. Have you prepared an exhibit that shows the recoverable environmental costs for the actual/estimated period January 2015 through December 2015?

A. Yes. Exhibit No. _____ (PAR-2), 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 2016 through December 2016.

Q. What has Tampa Electric calculated as the actual/estimated true-up for the current period to be applied to the January 2016 through December 2016 ECRC factors?

A. The actual/estimated true-up applicable for the current period, January 2015 through December 2015, is an over-recovery of $4,535,273. 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 2015 ECRC factors?

A. No, Tampa Electric is not including costs for any new environmental projects that were not anticipated or included in its 2015 ECRC factors.

Q. What depreciation rates were utilized for the capital projects contained in the 2015 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 2015 through December 2015?

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. How did the actual/estimated project expenditures for the January 2015 through December 2015 period compare with the company's original projections?

A. As shown on Form 42-4E, total O&M costs are expected to be $3,304,559 less than the amount that was originally projected. The total capital expenditures itemized on Form 42-6E, are expected to be $627,932 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 $638,508 or 10.2 percent less than projected. This variance is due to a forced outage on Big Bend Unit 3 that resulted in a decrease in chemical consumption.

- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is estimated to be $10,930 or 41.8 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 Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance is estimated to be $1,399,241 or 13.7 percent less than projected. This variance is due to a forced outage on Big Bend Unit 2, which resulted in a decrease in chemical consumption.

- **Big Bend PM Minimization and Monitoring: The Big Bend PM** Minimization and Monitoring project variance is estimated to be $64,608 or 7.7 percent greater than projected. This variance is due to an increase in price for routine monthly Best Operating Practices ("BOP") inspections.

- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance is estimated to be $9,679 or 48.4 percent less than originally projected. This variance is due to an extended outage for Polk Unit 1. Due to the extended outage, there was minimal maintenance associated with this project.

- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance is estimated to be $24,000 or 50 percent less than projected. The actual/estimated maintenance cost associated with this project is less than what was originally projected because less maintenance work was needed than projected.

- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is estimated to be $24,000 or 50 percent less than projected. The actual/estimated maintenance costs associated with this project is less than what was originally projected because less maintenance work was needed than originally projected.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program variance is estimated to be $242,440 or 80.8 percent less than what was originally projected. This variance is due to ongoing negotiations with the FDEP regarding groundwater treatment at Bayside Station.

- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study variance is estimated to be $589,348 or 61.4 percent less than originally projected. This variance is due to ongoing negotiations regarding the use of existing 316(b) data. As a result, there is a delay in the timing of work to be done to meet the requirements of the May 2014 rule.

- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is estimated to be $182,976 or 8.5 greater than originally projected. This variance is 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 $620,936 or 24.8 percent less than originally projected due to an extended outage that decreased the amount of ammonia consumed.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is estimated to be $207,081 or 10.2 percent greater than originally projected. Greater ammonia consumption is expected because Big Bend Unit 3 is expected to operate for a greater number of hours than originally projected.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is estimated to be $60,715 or 5.5 percent greater than originally projected. The actual/estimated consumption of ammonia is expected to be greater than originally projected because Big Bend Unit 4 is expected to operate for a greater number of hours than originally projected.

- **Mercury Air Toxics Standards (“MATS”):** The MATS program variance is expected to be $46,608 or 20.3 percent less than originally projected. This variance is due to Tampa

Electric utilizing internal labor resources for stack testing. The original projection included costs for contractor labor to complete the testing.

- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility program variance is expected to be $211,895 or 16.5 percent less than originally projected. This variance is due to extended usage of the old storage facility, resulting in less utilization of this storage facility than originally projected.

Capital Investment Project Variances

- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility project variance is estimated to be $303,704 or 10.8 percent less than projected. The depreciation rate used to project depreciation amounts for this project, in the original projection, was inaccurate. The company assigned the correct depreciation rate, reducing the expected amount of cost recovery for this project for the actual/estimated period.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150007-EI
FILED: 08/31/2015

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.

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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 2016 through December 2016. 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 2016.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2016 through December 2016?

A. Yes. Exhibit No. ___ (PAR-3), 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 2016.

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-3), Document No. 7, on Form 42-7P. These annualized factors will apply for the period January through December 2016.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2016 through December 2016?

A. The net true-up applicable for this period is an over-recovery of $619,637. This consists of the final true-up under-recovery of $3,915,636 for the period of January 2014 through December 2014 and an estimated true-up over-recovery of $4,535,273 for the current period of January 2015 through December 2015. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-9E of Exhibit No. ___ (PAR-2) filed with the Commission on July 31, 2015.

Q. Did Tampa Electric include any new environmental compliance projects for ECRC cost recovery for the period from January 2016 through December 2016?

A. No, Tampa Electric is not including any new environmental compliance projects for ECRC cost recovery during 2016.

Q. What are the existing capital projects included in the calculation of the ECRC factors for 2016?

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 2016. 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 2016?

A. Yes. Form 42-3P contained in Exhibit No. ___ (PAR-3) summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 25, provides the calculations of the costs, which result in recoverable jurisdictional capital costs of $54,181,029.

Q. What are the existing O&M projects included in the calculation of the ECRC factors for 2016?

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 2016. 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 and 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 a schedule showing the calculation of the recoverable O&M project costs for 2016?

A. Yes. Form 42-2P contained in Exhibit No. ___ (PAR-2) summarizes the recoverable jurisdictional O&M costs for these projects which total $27,074,547 for 2016.

Q. Did you prepare 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 2016?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $81,255,576.

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 2016 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 2016 which Tampa Electric is seeking approval?

A. The computation of the billing factors is shown in Exhibit No. ___ (PAR-3) Document No. 7, Form 42-7P. In summary, the January through December 2016 proposed ECRC billing factors are as follows:

Rate Class	**Factor by Voltage Level(¢/kWh)**
RS Secondary	0.432
GS, TS Secondary	0.431

GSD, SBF	
Secondary	0.429
Primary	0.424
Transmission	0.420
IS	
Secondary	0.423
Primary	0.419
Transmission	0.414
LS1	0.427
Average Factor	0.430

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 2016.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2016 through December 2016?

A. Tampa Electric used 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 2016 through December 2016 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 0.430 cents per kWh. This includes the projected capital and O&M revenue requirements of $81,255,576 associated with a total of 31 environmental projects and a net true-up over-recovery provision of $619,637. My testimony also explains that the projected environmental expenditures for 2016 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150007-EI
FILED: 08/31/2015

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 2016 through December 2016 projection period are activities necessary for the company to comply with various environmental requirements. Specifically, I will describe the ongoing activities related to 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 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 ("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. Tampa Electric has implemented the requirements of the Orders, and now these agreements have been terminated by the corresponding court systems. The ongoing requirements of these projects, which are further described later in my testimony, are now part of the Big Bend Title V operating permit (0570039-072-AV). The projects that are now required under the operating permit are listed below.

- Big Bend Minimization Program
- Big Bend NOx Emission Reduction Program
- Big Bend Units 1 – 3 Pre–SCR Projects
- Big Bend Units 1 – 4 SCR Projects

Q. Does the termination of the Orders change any of the environmental compliance requirements applicable to the company's generating units?

A. No, the termination of the Orders does not change any of the environmental compliance requirements applicable to the company's generating units. They are now part of the Title V operating permit.

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 2016 through December 2016.

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. Tampa Electric does not anticipate any capital expenditures for this program during 2016; however, the O&M expenses associated with existing and recently installed BOP and BACT equipment and continued implementation of the BOP procedures are expected to be $924,000.

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 2016 through December 2016.

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 2016; however, the company will perform maintenance on the previously approved and installed NO_x reduction equipment. This activity is expected to result in approximately $130,000 of O&M expenses during 2016.

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 2016 through December 2016.

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 2016 through December 2016, 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 $42,000 for Big Bend Unit 1 Pre-SCR, $42,000 for Big Bend Unit 2 Pre-SCR and $42,000 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 2016 SCR O&M

expenses are projected to be $2,025,000 for Big Bend Unit 1 SCR, $1,613,000 for Big Bend Unit 2 SCR, $2,032,000 for Big Bend Unit 3 SCR and $2,070,000 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 2016 through December 2016.

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.

The company does not anticipate any capital expenditures during January 2016 through December 2016 for the Big Bend Unit 3 FGD Integration project; however, O&M expenses are projected to be $5,844,840 for consumables, primarily anhydrous ammonia, and ongoing maintenance. There are not any anticipated capital expenditures for the Big Bend Units 1 & 2 FGD project during January 2016 through December 2016. O&M expenses are projected to be $9,795,402 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 2016 through December 2016.

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 2016 through December 2016, 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. The company anticipates that an additional study will not be required.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated O&M expenditures for the period of January 2016 through December 2016.

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 2016 through December 2016, Tampa Electric projects O&M expenses associated with the consumable goods (primarily anhydrous ammonia) to be approximately $204,000 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 2016 through December 2016.

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. The final rule adopted under Section 316(b), the Cooling Water Intake Structures ("CWIS") Rule, became effective October 14, 2014. Tampa Electric is currently finalizing its compliance strategy for the CWIS Rule and is working with the regulating authority to determine the need and scheduling for biological, financial and technical study elements necessary to comply with the rule. These elements will ultimately be used by the regulating authority to determine the necessity of cooling water system retrofits for Big Bend and Bayside Power Stations. Retrofits could include the installation of cooling towers or screening facilities. Tampa Electric projects O&M expenditures to be $960,000 for the period January 2016 through December 2016 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 2016 through December 2016.

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 2016 through December 2016, 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 2016 through December 2016.

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 2016 through December 2016, Tampa Electric projects O&M expenses associated with the sampling activities to be approximately $25,000.

Q. Please describe the MATS program activities.

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 October 16, 2015 to show full compliance 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.

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 (the requirements now included in the Big Bend operating permit); 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 a new rule under National Emission Standards for Hazardous Air Pollutants pursuant to a court order referred to as the MATS rule. The proposed rules replace CAMR and are expected to reduce not only mercury but acid gas, organics and certain non-mercury metals emissions. The final MATS rule was released in February 2012 and required implementation by April 2015. Tampa Electric 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. The company's compliance with these standards for mercury, acid gases, and non–mercury metals began on April 16, 2015 at Big Bend Station and Polk Power Station. Full compliance with the rule is required by October 16, 2015, and Tampa Electric is on course to fully comply with the MATS rules by the compliance date.

Q. Please provide the MATS program estimated capital and O&M expenditures for the period January 2016 through December 2016.

A. For 2016, Tampa Electric does not anticipate any capital expenditures under the MATS program; however, O&M expenditures are projected to be $230,000 for testing requirements and maintenance of equipment.

Q. Please describe the GHG Reduction Program activities and provide the estimated capital and O&M expenditures for the period of January 2016 through December 2016.

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 2016. For 2016, this activity 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 2016 through December 2016.

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 project was placed in-service in November 2014. For 2016, Tampa Electric does not anticipate any capital expenditures; however, projected O&M expenses for this program during 2016 are $900,000.

Q. Please describe your company's plans for compliance with the recently finalized EPA Coal Combustion Residuals ("CCR") Rule and provide estimated expenses if available.

A. On April 17, 2015, EPA issued a final rule to regulate coal combustion residuals ("CCRs") as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). The rule, which becomes effective on October 19, 2015, covers all operational CCR disposal facilities, as well as inactive impoundments which contain CCRs and liquids. The Big Bend Unit 4 Economizer Ash Ponds and the East Coalfield Stormwater Pond (converted former slag fines pond), will be regulated under the rule, at a minimum. The applicability of the rule to other CCR management units at Big Bend is also being evaluated at this time. Initial compliance costs for structural integrity evaluations, groundwater monitoring well installation, dike inspections and other administrative requirements of this rule may be incurred during 2016. Tampa Electric did not project and include costs for this program in its 2016 ECRC factor due to the uncertainty surrounding the requirements. The company is continuing its evaluation and plans to petition the Commission for cost recovery for this program. Potential Commission-approved costs for this project will be proposed for cost recovery in Tampa Electric's 2016 actual-estimate filing.

Q. Please summarize your testimony.

A. Tampa Electric's settlement agreements with FDEP and EPA required significant reductions in emissions from Tampa Electric's Big Bend and Gannon Stations have been terminated due to the company having satisfied all requirements as set forth by the CFJ and CD. Ongoing requirements for projects originating with the Orders are included in the Big Bend operating permit and discussed throughout my testimony. 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 2016. The on-going requirements of these of the CFJ and CD have been incorporated into Big Bend's Title V Operating Permit (1050233 – 072 – AV). Additionally, my testimony identified other projects that are required for Tampa

Electric to meet environmental requirements, and I provided the associated 2016 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. 150007-EI
April 1, 2015

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 2014.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2014 through December 2014 with the approved estimated true-up amounts.

A. As reflected in Mr. Boyett's Schedule 6A, the actual recoverable capital costs were $118,824,740 as compared to $118,625,423 included in the Estimated True-up filing. This resulted in a net variance of $199,318 above 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 $210,262 or 0.2% in the Air Quality Compliance Program (Line item 1.26)

A. This variance is a result of several contributing factors. First, although Mercury CEMS equipment was installed on the scrubber stack during the period, Gulf delayed the installation of Mercury CEMS equipment on two other stacks at Plant Crist while related updates and corrections to the MATS rule are occurring. Second, some construction activities associated with the Plant Daniel Bromine Injection and Activated Carbon projects were moved from 2014 to 2015. Third, Gulf's Plant Crist Unit 6 SCR catalyst replacement was delayed while Gulf selected a new catalyst.

Q. How do the actual O&M expenses for the period January 2014 to December 2014 compare to the amounts included in the Estimated True-up filing?

A. Mr. Boyett's Schedule 4A reflects that Gulf's recoverable environmental O&M expenses for the current period were $29,192,476**,** as compared to the estimated true-up of $30,247,005. This resulted in a variance of ($1,054,529) or 3.5% below the estimated true-up. I will address ten O&M projects and/or programs that contribute to this variance: General Water Quality, 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, Annual NOx Allowances, and SO_2 Allowances.

Q. Please explain the variance of ($502,453) or (16.9%) in (Line Item 1.6), General Water Quality.

A. This line item includes expenses related to Plant Crist's industrial wastewater pond dredging project. Due to project efficiencies and there being less solids in the pond to remove, Plant Crist was able to return the pond to its original bottom elevation at a lower cost than originally projected.

Q. Please explain the variance of $755,110 or 17.3% in (Line Item 1.7), Groundwater Contamination Investigation.

A. This line item includes expenses related to substation investigation and remediation activities. This variance is due to additional work being required to complete soil and groundwater studies necessary to comply with the Florida Department of Environmental Protection established timeline. This variance is also due to an increase in the cost of the Holmes Creek Substation project. The cost increase is primarily from higher than expected excavation volumes of contaminated soil that resulted from Gulf encountering below-ground concrete footers that were deeper than expected.

Q. Please explain the variance of ($14,401) or (29.0%) 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 primarily a timing difference due to paying Plant Crist's five year permit renewal fee of $7,500 in March 2015 instead of November of 2014 as initially projected.

Q. Please explain the variance of $126,496 or 19.4% 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 ($47,905) or (32.8%) in (Line item 1.12), Above Ground Storage Tanks.

A. This variance is primarily due to postponing the district office storage tank integrity tests and delaying a portion of the Plant Smith aboveground storage tank maintenance work to early 2015. Plant Smith originally planned to coat the concrete secondary containment areas around several of the tanks in late 2014; however, the work was rescheduled for early 2015 due to rainfall events. The Plant Crist above ground storage maintenance expenses were also less than originally anticipated.

Q. Please explain the variance of ($19,374) or (48.3%) 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 ($1,143,245) or (43.2%) 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 and 5 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 an extension of the schedule for painting of structure steel associated with Plant Crist's Unit 7 SCR into 2015 and the job costing less than original projected.

Q. Please explain the O&M variance ($731,104) or (4.3%) 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, Plant Crist Unit 6 SCR and the Plant Smith Units 1 and 2 SNCRs. More specifically, this line item includes the cost of urea, limestone, and the general operation and maintenance activities associated with Gulf's Air Quality Compliance Program. This variance is primarily due to the Plant Crist units operating less than projected. Lower operation of the units results in less urea and limestone being needed, as well as less maintenance being required for the equipment.

Q. Please explain the variance of $400,136 or 172.2 % in Annual NOx Allowances (Line Item 1.24).

A. This variance is the result of Gulf expensing its remaining NOx CAIR allowances after the U.S. Court of Appeals lifted the court-imposed stay on EPA's implementation of the Cross-state Air Pollution Rule (CSAPR). That court action ended the CAIR program in December 2014. CAIR annual and seasonal emission allowances will not be transferrable to the CSAPR program.

Q. Please explain the variance of $44,194 or 7.2 % in SO2 Allowances (Line Item 1.26).

A. This variance is due to a scrubber outage during the month of October at Plant Crist. During that time, Crist units 4, 5, and 6 operated in the scrubber by-pass mode which resulted in the need to utilize more allowances than projected.

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

A. Yes.

ERRATA SHEET

Docket No. 150007-EI
Name: James O. Vick
Date: October 9, 2015

Page 4 Lines 3-6

"This variance is primarily due to a delay in replacing the FGAS fans in Plant Crist's Unit 7 SCR. In the 2014 fall outage, an inspection of the fans found that the fans had more remaining life than anticipated thus delaying the replacement of the fans."

should read:

"This variance is primarily due to two expenditures. First, in the 2014 fall outage, an inspection of the Plant Crist Unit 7SCR Flue Gas Sample (FGAS) fans found that the fans had more remaining life than anticipated thus delaying the replacement of the fans beyond 2015. Second, Gulf's Plant Crist Unit 6 flame scanners were not included in Gulf's 2015 Projection filing. The flame scanners are a necessary component of the Low NOx Burners and have reached the end of their useful life."

10-8-15
DATE

James O. Vick
James O. Vick

STATE OF FLORIDA
COUNTY OF ESCAMBIA

I, the undersigned authority, certify that personally appeared before me James O Vick and was duly sworn.

WITNESS my hand and official seal this 8th day of October, 2015.

Melissa A. Darnes
Notary Public, State of Florida

NOTARY PUBLIC STATE OF FLORIDA
MELISSA A. DARNES
MY COMMISSION # EE 150873
EXPIRES: December 17, 2015
Bonded Thru Budget Notary Services

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of James O. Vick
Docket No. 150007-EI
Date of Filing: July 31, 2015

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 2015. 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 2015 through December 2015 with the approved projected amounts.

A. As reflected in Mr. Boyett's Schedule 6E, the recoverable capital costs approved in the original projection total $119,597,918 as compared to the estimated true-up amount of $123,962,048. This results in a variance of $4,364,129 or 3.6%.

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 $4,364,129 more than the capital costs included in the 2015 Projection filing. One driver that impacts multiple capital projects is the difference between the weighted average cost of capital (WACC) used in the 2015 Projection filing versus the WACC applied to the July through December 2015 period in this 2015 Estimated/Actual True-up filing. In accordance with Commission Order No. PSC-12-0425-PAA-EU, the 2015 Projection filing used the WACC presented in Gulf's May 2014 Earnings Surveillance Report for January through December 2015. In this 2015 Estimated/Actual True-Up filing, the projected July through December 2015 period uses the WACC presented in Gulf's May 2015 Earnings Surveillance Report. After taking this item into consideration, there is a positive variance of approximately $5,107,570 that is largely attributed to three capital projects: 1) Smith Water conservation ($315,566); 2) Crist FDEP Agreement for Ozone Attainment $165,717; and 3) Air Quality Compliance Program $5,152,794. The variances attributed to these programs will be discussed below.

Q. Please explain the capital variance of ($315,566) or (20.4%) reflected in Smith Water Conservation (Line item 1.17).

A. The Smith Water Conservation variance is due to delays in equipment manufacturing which caused the contractor installation schedule to be delayed for the piping and a temporary pump station.

Q. Please explain the capital variance of $165,717 or 1.3% reflected in the Crist FDEP Agreement for Ozone Attainment Program (Line Item 1.19).

A. This variance is primarily due to a delay in replacing the FGAS fans in Plant Crist's Unit 7 SCR. In the 2014 fall outage, an inspection of the fans found that the fans had more remaining life than anticipated thus delaying the replacement of the fans.

Q. Please explain the capital variance of $5,152,794 or 5.7% reflected in the Air Quality Compliance Program (Line Item 1.26).

A. The line item variance is primarily due to two budget items. First, Plant Daniel anticipates bringing the Unit 1 scrubber and common scrubber equipment in-service in the month of October and the Unit 2 scrubber in-service in November. Both units and common equipment were projected to come in-service in December. Secondly, Plant Crist's modifications to Plant Crist's Gypsum Cell #2 are allowing the plant to extract more gypsum out of the pond and sell that gypsum. The modifications to cell #2 and the increase in demand for the gypsum have allowed the plant to delay construction of cell #1.

Q. How do the estimated/actual 2015 O&M expenses compare to the original 2015 projections?

A. Mr. Boyett's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated at $27,076,209 as compared to $28,103,327 the amount projected in the 2015 Projection Filing for a variance of ($1,027,118) or (3.7%). I will address eight O&M

projects and programs that mostly contribute to this variance: Emissions Monitoring, General Water Quality, Above Ground Storage Tanks, Sodium Injection, FDEP NOx Reduction Agreement, Air Quality Compliance Program, Crist Water Conservation, and SO2 Allowances.

Q. Please explain the O&M variance of ($86,864) or (10.8%) in (Line item 1.5), the Emissions Monitoring program.

A. The Emissions Monitoring variance is primarily due to Plant Daniel's emissions testing charges costing less than projected.

Q. Please explain the O&M variance of ($815,453) or (38.1%) in (Line item 1.6), the General Water Quality program.

A. The General Water Quality variance is primarily due to the discontinuing of some 316(b) biological evaluations at Plant Smith since the plant will cease operations with its coal-fired units in March 2016 and a delay in the 316(b) activities at Plant Crist until further discussions with DEP are completed.

Q. Please explain the O&M variance of $73,854 or 62.9% in (Line item 1.12) Above Ground Storage Tanks.

A. The Above Ground Storage Tanks variance is primarily due to work at Plant Smith related to coating of the concrete secondary containment areas around several tanks. The work was rescheduled to 2015 due to rainfall events in late 2014.

Q. Please explain the variance of ($41,607) or (39.3%) 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 Crist and Plant Smith. 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 operated and during this period these units have operated less than originally projected.

Q. Please explain the O&M variance of ($227,577) or (11.2%) 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 painting project of Plant Crist's Unit 7 SCR coming in under budget.

Q. Please explain the O&M variance $372,874 or 2.3% 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 limestone, ammonia, urea and general operation and maintenance activities included in Gulf's Air Quality Compliance Program. The line item variance is primarily due to $1,669,171 of MATS cost associated with Plant Smith. These costs were incurred by Gulf in determining its MATS compliance strategy for Plant Smith. Plant Crist scrubber limestone expenses are lower than projected due to lower utilization of Gulf's coal-fired units. Plant Daniels scrubber limestone expenses are higher than projected due to the units coming on-line and in-service earlier than projected.

Q. Please explain the variance of ($61,915) or (20.7%) in Crist Water Conservation (Line Item 1.22).

A. The Crist Water Conservation line item includes O&M expenses associated with the Plant Crist reclaimed water system. The line item variance is primarily due to lower utilization of Plant Crist's coal-fired units which in turn means lower demand for sulfuric acid.

Q. Please explain the variance of ($63,407) or (18.1%) in SO2 Allowances (Line Item 1.26).

A. Plant Crist and Plant Daniel operated less than projected and thus fewer allowances were utilized.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
James O. Vick
Docket No. 150007-EI
Date of Filing: August 31, 2015

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 2016 through December 2016, including two new environmental programs.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes, my exhibit consists of the Coal Combustion Residual (CCR) regulation, the draft Plant Scholz National Pollutant Discharge Elimination System (NPDES) industrial wastewater permit, and the proposed Steam Electric Power Effluent Limitations Guidelines and Standards (ELG) regulation.

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

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-3. 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 four programs that were previously approved by the Commission with activities that have projected capital expenditures during 2016. These programs include: Continuous Emission Monitoring Systems (CEMS) – Plants Crist, Scholz, Smith, and Daniel, Smith Water Conservation, Crist FDEP Agreement for Ozone Attainment, and the Air Quality Compliance program.

Q. Have all of the projects addressed in Gulf's testimony and exhibits been previously approved by the Commission?

A. No. Gulf is including two new Water Quality programs, the Coal Combustion Residual (CCR) program and the Steam Electric Power Effluent Limitations Guidelines (ELG) program, in addition to the programs previously approved by the Commission.

Q. Mr. Vick, please describe the Coal Combustion Residual program that Gulf seeks to recover through the ECRC.

A. The new program is related to the regulation of Coal Combustion Residuals by the United States Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FDEP). For Gulf's generating plants, these new regulatory compliance obligations are pursuant to either the new CCR rule adopted earlier this year or in new permit requirements added by FDEP; through National Pollutant Discharge Elimination System (NPDES) permits issued for each of Gulf's generating facilities pursuant to authority granted under the Clean Water Act.

On April 17, 2015 EPA published the final CCR rule in the Federal register regulating CCR disposal under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The CCR rule is located in Title 40 Code of Federal Regulations (CFR) Parts 257 and 261 (See Exhibit JOV-1). The CCR rule regulates the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste at active generating power plants. The CCR rule includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills (collectively referred to as "CCR Units"). Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. The new criteria will apply to CCR Units at Gulf's Plants Crist, Smith, and Daniel.

A draft NPDES renewal permit for Plant Scholz (FL0002283) was issued on August 24, 2015 and is expected to become final in the fourth quarter of

2015 (See Exhibit JOV-1). This permit renewal has new conditions requiring closure of the Plant Scholz CCR Unit. Pursuant to the permit, the closure plan is required to be submitted to the FDEP in 2016 for review and approval. Once approved, Gulf will move forward with activities required for closure. The expenses associated with the Plant Scholz CCR Unit will be reflected in Operation and Maintenance (O&M) Line Item 1.23.

Each plant will conduct engineering evaluations to meet the requirements for continued use of its CCR Units. By the effective date of the CCR rule, October 19, 2015, any CCR Unit subject to the EPA's new rule must have a publicly available website established, weekly and monthly inspections initiated, and a fugitive dust plan prepared. During 2015, Gulf is also required to install permanent markers at all CCR ponds and have annual inspections of the CCR impoundments and landfills performed by a professional engineer (PE). In 2016, Gulf will prepare closure and post-closure care plans for the CCR Units, conduct hydrologic and hydraulic capacity studies of the CCR ponds, compile a history of the structural integrity reports and design information for the CCR Units, prepare stormwater management plans, and conduct annual dust control and engineering inspections as well as groundwater monitoring. Costs associated with these activities are O&M expenses that are reflected on Line Item 1.23 of Mr. Boyett's Schedule 2P.

Gulf's projected 2015 CCR capital expenditures of $660,000 include installation of additional groundwater monitoring systems required for Plant

Crist, Plant Smith, and Plant Daniel. The proposed 2016 capital expenditures totaling $9,359,600 are associated with the installation of a new bottom ash handling system for Plant Crist, dust suppression control equipment for Plant Smith, as well as new CCR wastewater management systems for Plant Crist and Plant Smith (Line Item 1.28).

Q. Mr. Vick, please discuss the new Steam Electric Power Effluent Limitations Guidelines and Standards (ELG) program.

A. EPA is required to establish new ELG which are found in Title 40 of the Code of Federal Regulations, Part 423 (See Exhibit JOV-1). This regulation limits the discharge of pollutants into navigable waters and into publically owned treatment works by existing and new sources of steam electric power. The EPA is required to finalize revisions to the ELG by September 30, 2015. The proposed ELG regulations, as currently drafted, would require the installation of additional controls such as wastewater treatment systems and/or dry ash handling systems at Gulf's generating facilities. The ultimate impact of these proposed regulations will, however, depend on the specific requirements of the final rule, which could require short compliance timeframes to complete modifications.

During the 2015-2016 timeframe Gulf plans to complete water balance and engineering studies to evaluate further the impact of the proposed ELG regulatory options. The project costs will be recorded to a preliminary design and investigation account (deferred debit) until the rule is finalized and Gulf has determined the best option to comply with the regulation.

Q. Mr. Vick, please describe the projected 2016 capital expenditures for CEMS – Plants Crist, Scholz, Smith and Daniel (Line Item 1.5).

A. Gulf plans to relocate existing Plant Crist CEMS monitors that are currently located in bypass stacks to the individual unit's duct and to upgrade Plant Crist Unit 7 flue gas monitors. The CEMS monitors need to be relocated and upgraded due to the Mercury and Air Toxics Standards (MATS) rule requirements. Expenditures associated with these activities reflected in the 2016 projection filing are $3.1 million.

Q. Mr. Vick, please provide an update on the Smith Water Conservation project (Line Item 1.17).

A. As discussed in previous filings, Gulf has determined that it is feasible to inject reclaimed water into the Plant Smith deep injection well system. Gulf has installed three deep injection wells and will begin the process of installing piping and initial equipment for the pump station during the latter portion of 2015 and the first part of 2016. During 2016, Gulf will obtain additional operational data required to design the final pump station and wastewater treatment equipment as well as any additional piping. Expenditures associated with these activities reflected in the 2016 projection filing are $340,807.

Q. Mr. Vick, please describe the projects included in the 2016 projection for (Line Item 1.19) the Crist FDEP Agreement for Ozone Attainment.

A. Gulf plans to add or replace a layer of the Plant Crist Unit 7 SCR catalyst and install the Plant Crist Unit 6 flame scanner during 2016. In 2016, the effectiveness of the existing catalyst will have reached a point requiring either a replacement layer or the addition of another layer. Under either option, the replacement or additional layer will be a regenerated catalyst. The projected 2016 expenditures for this line item are $1,183,284.

Q. Mr. Vick, please describe the projected 2016 capital expenditures for the Air Quality Compliance program (Line Item 1.26).

A. The projected 2016 expenditures for this line item include completion of the work associated with the Plant Daniel scrubbers and CEMS equipment needed for Plant Crist and Plant Daniel to comply with the MATS regulation. Also, projected for this line item are capital retrofit projects for the Plant Crist scrubber. Gulf plans to replace Plant Crist's scrubber booster fan hubs, scrubber mist eliminator, and scrubber expansion joints, as well as increase the capacity of its scrubber wastewater treatment plant. The projected 2016 expenditures for this line item is $16,338,205.

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 the October to November 2015 time period. On August 19, 2015, the Plant Daniel Unit 1 scrubber had its initial gas flow. That activity initiated approximately 60 days of testing and optimization. The Unit 2 scrubber initial gas flow is planned for September, 2015. After the testing and optimization, the scrubbers will be drained and inspected prior to placing the scrubbers in-service. Other remaining major activities include commissioning all ancillary equipment, completing the waste water treatment system and finishing the liner at the gypsum storage area. The total projected amount for 2016 for Daniel scrubber expenditures is $8.5 million which is included in the $16.3 million of expenditures projected for the Air Quality Compliance Program, Line Item 1.26.

Q. Please discuss the status of the MATS rule and the controls and monitoring equipment needed to comply with the MATS regulations.

A. On June 29, 2015, the Supreme Court decided that the EPA interpreted the Clean Air Act unreasonably when it deemed cost irrelevant to the decision of whether regulation of power plants under section 112 of the Clean Air Act is “appropriate and necessary”. While the Court directed that the EPA must consider cost before deciding whether regulation of power plants is “appropriate and necessary”, the Court left it up to EPA to decide how to account for cost upon remand. The MATS regulations remain in effect and the EPA announced it intends to submit its cost analysis by spring 2016.

Gulf Power began installing MATS monitoring systems at Plant Crist in 2014 and Plant Daniel in 2015 in order to comply with the MATS rule. The Plant Crist MATS monitoring system will monitor mercury and particulate emissions. 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 2016 projected expenditures for the Plant Crist MATS monitoring systems are $3.2 million. The Plant Daniel MATS monitoring costs are included in the cost projection for the Plant Daniel scrubbers.

Q. Mr. Vick, are you including the purchase of allowances in your 2016 projection filing?

A. No, we are not currently projecting the need to purchase additional allowances during 2016.

Q. How do the projected Environmental O&M activities listed on Schedule 2P of Mr. Boyett's Exhibit CSB-3 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 other than the Coal Combustion Residual (CCR) program expenses (Line Item 1.23).

Q. Please describe the O&M activities included in the air quality category for 2016.

A. There are five O&M activities included in the air quality category that have projected expenses in 2016. 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 2016 recovery period total $560,352.

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 2016 estimated expenses for the Title V Program are $144,489.

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 $1,000.

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 2016 recovery period for these activities total $816,217.

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 2016 recovery period total $952,387.

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 $2,009,676.

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 $3,437,656 of incremental expenses for this line item during the 2016 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 $36,500 during the projected recovery period.

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 $16,974 during the 2016 projection period.

Line Item 1.23, is the new Coal Combustion Residual (CCR) program that was previously discussed on pages 4 through 6. Gulf is requesting ECRC recovery for certain CCR compliance activities that will be conducted beginning in 2015. The projected 2015 and 2016 CCR O&M expenses are $13.24 million.

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-3. 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 2016 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 $771,232 in 2016.

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 2016. 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 $164,181 are projected to be incurred during 2016.

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 $72,800 are projected to be incurred during 2016 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 2016 expenses for this line item total approximately $27.1 million which includes $9.5 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, valve maintenance and pump replacements. Expenses totaling $570,300 are projected to be incurred during 2016 for this line item.

Q. Please describe the emission allowance line item (Line Item 1.27).

A. This line item includes projected allowance expenses for Gulf's generation. Line Item 1.27 includes $226,209 of projected expenses for SO_2 allowances during 2016.

Q. Do each of the capital projects and O&M activities that have projected costs in 2016 meet the ECRC statutory guidelines?

A. Yes. The projects included in Gulf's 2016 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
C. Shane Boyett
Docket No. 150007-EI
Date of Filing: April 1, 2015

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520-0780. 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 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 final 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.

Counsel: We ask that Mr. Boyett's exhibit consisting of nine schedules be marked as Exhibit No. _____ (CSB-1).

Q. Are you familiar with the ECRC true-up calculation for the period January through December 2014 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 2016?
A. An amount to be collected of $912,783 was calculated, which is reflected on line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $912,783 to be collected was calculated by taking the difference between the estimated January 2014 through December 2014 under-recovery of $2,229,940 as approved in FPSC Order No. PSC-14-0643-FOF-EI, dated November 4, 2014, and the actual under-recovery of $3,142,723, 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 2014 through December 2014. 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 2014 through December 2014 with the estimated/actual O&M expenses approved in conjunction with the October 2014 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 2014 through December 2014 compares the actual recoverable costs related to investment with the estimated/actual amount approved in conjunction with the October 2014 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. Boyett, 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 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. 150007-EI
Date of Filing: July 31, 2015

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 of 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 2015 through December 2015 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-2).

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

A. Yes, I have.

Q. What has Gulf calculated as the estimated true-up for the January 2015 through December 2015 period to be refunded or collected in the period January 2016 through December 2016?

A. The estimated true-up for the current period is an under-recovery of $1,699,128 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 2014 final true-up under-recovery amount of $912,783. The sum of $2,611,911 will be collected from customers during the January 2016 through December 2016 period. The detailed calculations supporting the estimated true-up for 2015 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 2015 through December 2015. 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 2015 through December 2015 to the projected O&M expenses approved by the Commission in Docket No. 140007-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 estimated true-up testimony.

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

A. Schedule 6E for the period January 2015 through December 2015 compares the estimated/actual recoverable costs related to investment to the projected amount approved in Docket No. 140007-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 2015 through June 2015 is based on the weighted average cost of capital (WACC) presented in Gulf's May 2014 Earnings Surveillance Report. For July 2015 through December 2015 the rate of return used is the WACC presented in Gulf's May 2015 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. 150007-EI
Date of Filing: August 31, 2015

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 of 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 2016 through December 2016.

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-3).

Q. What environmental costs is Gulf requesting recovery of 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 2016 through December 2016. Schedule 2P of Exhibit CSB-3 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-3.

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 2015 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, 2016 through December 31, 2016.

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. 130007-EI, investment costs recoverable through ECRC were broken down within the retail jurisdiction based on the 12-MCP and 1/13th 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 2016 through December 2016?

A. The total projected jurisdictional recoverable costs for the period January 2016 through December 2016 is $197,765,402 as shown on line 1c of Schedule 1P of Exhibit CSB-3. This includes costs related to O&M activities of $48,094,205 and costs related to capital projects of $149,671,197 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 2016 through December 2016 and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $200,521,584 for the period January 2016 through December 2016 as shown on line 5 of Schedule 1P of Exhibit CSB-3. This amount includes the recoverable costs related to the projection period and the total true-up cost of $2,611,911 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-3.

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 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-3.

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-3 summarizes the energy and demand portions of the total requested revenue requirement. The energy-related recoverable revenue requirement of $41,172,439 for the period January 2016 through December 2016 was allocated using the energy allocator, as shown in column three on Schedule 7P of Exhibit CSB-3. The demand-related recoverable revenue requirement of $159,349,145 for the period January 2016 through December 2016 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 $21.09 monthly for the period January 2016 through December 2016.

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 2016 and will continue through the last billing cycle of December 2016.

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

A. Yes.

CHAIRMAN GRAHAM: Exhibits.

MR. MURPHY: Staff has compiled a stipulated Comprehensive Exhibit List which includes the prefiled exhibits attached to each witness's testimony in this case and staff's exhibits. The list has been provided to the parties, the Commissioners, and the court reporter. This list is marked as the first hearing exhibit, and the other exhibits should be marked as set forth in the chart.

My understanding is that OPC and Gulf would like to identify and add their agreement as an exhibit in the hearing.

CHAIRMAN GRAHAM: OPC.

MR. REHWINKEL: Yes. Thank you, Mr. Chairman. The Public Counsel and Gulf would ask that you -- we passed out an exhibit just now -- that you mark as an exhibit the deferral stipulation for Plant Scholz, CCR Unit 1, it be given an exhibit number.

CHAIRMAN GRAHAM: It looks like staff has assigned them Exhibit 46.

(Exhibit 46 marked for identification.)

MR. REHWINKEL: Okay. And this -- the staff has accurately characterized the stipulation in the Prehearing Order that you signed, but we ask just for completion of the record that the exact language of the stipulation and the transmittal be put into the record. So that's our motion.

CHAIRMAN GRAHAM: Any other comments? Okay. So, staff, am I just moving this exhibit into the record?

MR. MURPHY: I think you've identified it and he's moved it. You can move it in, but we would move it in with our whole list at your pleasure.

CHAIRMAN GRAHAM: We'll just move it in right now.

MR. MURPHY: Okay.

CHAIRMAN GRAHAM: So we'll move that into the record.

(Exhibit 46 admitted into the record.)

MR. REHWINKEL: Thank you.

MR. MOYLE: I just want to -- out of -- to make crystal clear, I mean, this is an issue that may be coming back at some point, and FIPUG has taken no position on it but reserve the right, you know, to get engaged on the issue if and when it comes back.

CHAIRMAN GRAHAM: Sure. Anyone else? Staff?

MR. MURPHY: At this time staff asks that the Comprehensive Exhibit List marked as Exhibit 1 be moved into the record.

CHAIRMAN GRAHAM: We will move Exhibit 1 into the record.)

(Exhibit 1 marked for identification and admitted into the record.)

MR. MURPHY: You've already moved 46 in, so staff asks that all exhibits be included in the record as set forth in the Comprehensive Exhibit List, Nos. 2 through 45.

CHAIRMAN GRAHAM: We will move Exhibits 2 through 45.

(Exhibits 2 through 45 marked for identification and admitted into the record.)

So does this conclude our hearing?

MR. MURPHY: Yes. I believe that no post-hearing filings are necessary and there's nothing further.

CHAIRMAN GRAHAM: All right. So we will adjourn docket 07.

(Hearing adjourned at 1:24 p.m.)

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 13th day of November, 2015.

Linda Boles

LINDA BOLES, CRR, RPR
FPSC Official Hearings Reporter
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