BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 160007-EI

ENVIRONMENTAL COST RECOVERY
CLAUSE.
________________________________/

Volume 1

Pages 1 through 232

PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN JULIE I. BROWN COMMISSIONER LISA POLAK EDGAR COMMISSIONER ART GRAHAM COMMISSIONER RONALD A. BRISÉ COMMISSIONER JIMMY PATRONIS
DATE:	Wednesday, November 2, 2016
TIME:	Commenced at 9:50 a.m. Concluded at 9:54 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, CRR, RPR Official FPSC Reporter (850) 413-6734

APPEARANCES:

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

JAMES D. BEASLEY, J. JEFFRY WAHLEN, and 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 and STEVEN R. GRIFFIN, ESQUIRES, Beggs & Lane, P.O. Box 12950, Pensacola, Florida 32591-2950, appearing on behalf of Gulf Power Company.

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

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:)

JAMES W. BREW and LAURA WYNN, ESQUIRES, Stone Mattheis 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.

J.R. KELLY, PUBLIC COUNSEL; CHARLES REHWINKEL; ERIK SAYLER; PATRICIA A. CHRISTENSEN; and STEPHANIE MORSE, ESQUIRES, Office of Public Counsel, c/o the Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

CHARLIE MURPHY and BIANCA LHERISSON, ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, Advisor to the Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850.

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.

No exhibits in this volume

P R O C E E D I N G S

CHAIRMAN BROWN: I'd like to -- there are five dockets, as you know, that we are going to address today, and we will be taking appearances all at once today. I know some folks have replaced other folks and made notices of appearances. But, please, when you enter your appearance, declare the dockets that you're entering the appearance for.

Also, I know that after the parties make their appearances, staff will be needing to make theirs. So we're going to start right now with Florida Power & Light.

MR. BUTLER: Thank you, Madam Chair.

John Butler appearing on behalf of Florida Power & Light Company in the 01, 02, and 07 dockets. I'd also like to enter an appearance for Wade Litchfield in those three dockets, for Ken Rubin in the 02 docket, and Maria Moncada in the 01 and 07 dockets. Thank you.

CHAIRMAN BROWN: Thank you.

Duke.

MR. BERNIER: Good morning, Madam Chair. Matt Bernier with Duke Energy. I'd like to enter an appearance in the 01, 02, and 07 dockets. I'd also like to enter an appearance for Dianne Triplett in those same three dockets, and for John Burnett in the 01 docket.

CHAIRMAN BROWN: Thank you.

Gulf.

MR. BADDERS: Good morning. Russell Badders on behalf of Gulf Power. With me I have Jeffrey A. Stone, and Steve Griffin is also in this docket in 02, 01, and 07.

CHAIRMAN BROWN: Thank you.

TECO.

MR. BEASLEY: Good morning, Madam Chair. Jim Beasley in the 01, 02, and 07 dockets on behalf of Tampa Electric Company. I'd also like to enter an appearance for J. Jeffry Wahlen and Ashley M. Daniels in the same dockets.

CHAIRMAN BROWN: Thank you.

Mr. Moyle.

MR. MOYLE: Good morning.

CHAIRMAN BROWN: Good morning.

MR. MOYLE: Jon Moyle on behalf of the Florida Industrial Power Users Group, FIPUG. And I'd also like to enter an appearance for Karen Putnal.

CHAIRMAN BROWN: Thank you. And the dockets that you will be --

MR. MOYLE: Oh, I'm sorry. 01, 02, and 07.

CHAIRMAN BROWN: Thank you.

MR. MOYLE: Thank you.

MS. SPARKMAN: Good morning. My name is Paula Sparkman, and I'm here on behalf of Sebring Gas in the 04 docket.

CHAIRMAN BROWN: Thank you.

Good morning.

MR. MUNSON: Good morning. I'm Greg Munson. I'm here on behalf of Florida City Gas in the 03 and 04 dockets. Also here on behalf of Florida Public Utilities in the 01 and 02 dockets; Florida Public Utilities, FPUC-Fort Meade in the 03 docket; Florida Public Utilities, FPUC-Fort Meade, FPUC-Indiantown District, Florida Division of Chesapeake Utilities Corporation in the 04 docket.

CHAIRMAN BROWN: Very complicated.

MR. MUNSON: I have notes.

CHAIRMAN BROWN: Thank you.

Good morning.

MR. BREW: Good morning. James Brew for White Springs Agricultural Chemical/PCS Phosphate appearing in the 01, 02, and 07 dockets. And I'd like to make an appearance for Laura Wynn.

CHAIRMAN BROWN: Thank you.

Good morning, Mr. Wright.

MR. WRIGHT: Good morning, Madam Chairman, Commissioners. Robert Scheffel Wright and John T.

LaVia, III, appearing on behalf of the Florida Retail Federation in the fuel docket, 0001. Thank you.

CHAIRMAN BROWN: Thank you.

Good morning, Ms. Christensen.

MS. CHRISTENSEN: Good morning. Patricia Christensen on behalf of the Office of Public Counsel. I'd also like to put in an appearance for J.R. Kelly, the Public Counsel; Charles Rehwinkel; Erik Sayler; and Stephanie Morse in the 01, 02, 03, 04, and 07 dockets.

CHAIRMAN BROWN: Thank you so much.

All right. Back to staff.

MS. TAN: Lee Eng Tan for the 02 docket, Margo Leathers and Wesley Taylor for the 03 docket, Kelley Corbari for the 04 docket, Charles Murphy and Bianca Lherisson for the 07 docket, and Danijela Janjic and Suzanne Brownless for the 01 docket.

CHAIRMAN BROWN: Thank you.

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

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CHAIRMAN BROWN: And we have different staff. Ms. Lherisson --

MS. LHERISSON: Yes.

CHAIRMAN BROWN: -- are there any preliminary matters that we need to address?

MS. LHERISSON: Yes, Madam Chair. There are proposed stipulations on all issues, and all parties either agree or take no position on the proposed stipulations that are before the Commission today.

In this respect, Issues No. 3, 4, and 7 are nuanced as they relate to FPL and contain fallout numbers from the FPL rate case. By approving the affected FPL stipulations, the Commission is flowing through to this docket the decision in the rate case regarding allocation of cost to rate groups. This is being done for consistency and to avoid confusion with respect to rates. Opening statements, if any, are limited to three minutes per party.

CHAIRMAN BROWN: Thank you, Ms. Lherisson.

It appears that there are no contested issues in this docket, so do any parties wish to make a statement?

Seeing none, we will move to the prefiled testimony.

MS. LHERISSON: Staff asks that the prefiled testimony of all witnesses be entered into the record at this time as though read.

CHAIRMAN BROWN: We will go ahead and enter into the record all of the prefiled testimony in this proceeding as though the read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 160007-EI

APRIL 1, 2016

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. Please state your education and business experience.

A. I graduated from North Carolina Agricultural & Technical State University with a Bachelor's degree in Accounting in 1977. I subsequently earned a Master of Business Administration degree from the University of Wisconsin in 1982. Prior to joining FPL in 2006, I held various accounting positions at Phillips Petroleum Company and later Centel Corporation. At FPL, I have held positions of increasing responsibility in the Accounting Department, including various supervision assignments relating to accounting research, financial reporting, development and application of overhead rates, and property accounting. I spent ten years in the Regulatory Affairs Department as Principal Regulatory Coordinator and later as Regulatory Issues Manager primarily responsible for managing and coordinating regulatory accounting and finance dockets. In 2008, I assumed my current position as Director, Cost Recovery Clauses, where I am responsible for providing direction as to cost recovery through cost recovery clauses and the overall preparation and filing of all cost recovery clause documents including testimony and discovery.

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 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-1 contained in Appendix I consists of nine forms.

- Form 42-1A reflects the final true-up for the period January 2015 through December 2015.
- 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 revenue requirements for Capital Investment Projects.
- Form 42-7A provides a summary of actual monthly revenue requirements 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 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 42-9A presents the capital structures, 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 2015 through December 2015, an over-recovery of $17,817,012, which FPL is requesting to be included in the calculation of the ECR factors for the January 2017 through December 2017 period.

The actual end-of-period under-recovery for the period January 2015 through December 2015 of $19,802,700 (shown on Form 42-1A, Line 3) minus the actual/estimated end-of-period under-recovery for the same period of $37,619,712 (shown on Form 42-1A, Line 6) results in the net true-up over-recovery for the period January 2015 through December 2015 (shown on Form 42-1A, Line 7) of $17,817,012.

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 2015 through December 2015. The end-of-period true-up shown on Form 42-2A, Lines 5 plus 6, is an under-recovery of $19,802,700. Additionally, Form 42-3A shows the calculation of the interest provision of $19,138, which is applicable to the end-of-period true-up over-recovery of $17,817,012.

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 recoverable project O&M and capital revenue requirements for January 2015 through December 2015 compare with FPL's actual/estimated amounts as presented in previous testimony and exhibits?

A. Form 42-4A shows that total project O&M was $15,565,417, or 23.2% lower than projected and Form 42-6A shows that total revenue requirements associated with project capital investments were $12,159 or 0.01% lower than projected. Individual project variances are provided on Forms 42-4A and 42-6A. Return on capital investments, depreciation and taxes for each capital project for the period January 2015 through December 2015 are provided on Form 42-8A, pages 12 through 38.

Q. Please explain the reasons for the significant variances in project O&M and revenue requirements associated with project capital investments.

A. FPL's variance explanations address variances of greater than $50,000 from actual/estimated amounts for a project, referring to these as "significant". There were no significant variances for capital investment projects. The significant variances in FPL's 2015 recoverable O&M expenses relate to the following projects:

O&M Variance Explanations

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

Project O&M was $68,467 or 9.3% higher than previously projected. The variance is primarily due to higher than projected costs for scaffolding required for the replacement of the CEMS sampling lines, known as Umbilicals, at the Ft. Myers plant. The project plan originally included the use of man lifts to replace the Umbilicals at Ft. Myers. However, during the final preparations for the project it was determined that scaffolding would be required due to access and safety concerns for the contractors performing the installation.

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

Project O&M was $567,754 or 25.1% lower than previously projected. The variance is primarily due to lower than projected costs resulting from favorable competitive bids associated with the painting of the tanks at Manatee Plant (Tank 1371A and 1371B) and Manatee Terminal (Tank 1271A and 1271B). In addition, the cost of Manatee Units 1 and 2 metering tank and light oil start up tank touch-up painting projects were less than projected, also due to favorable competitive bids.

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

Project O&M was $54,281 or 26.5% higher than previously projected. The variance is primarily due to costs associated with required HAZWOPER training for new employees that joined the Plant and Corporate response teams in 2015 as a result of turnover. Additionally, in response to unanticipated utilization of Oil Spill Response equipment, replacement materials had to be procured to return equipment inventories at each site to levels specified in the Facility Response Plans.

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

Project O&M was $220,846 or 8.8% lower than previously projected. The variance is primarily due to delays in obtaining equipment clearances (i.e., de-energize equipment) required for equipment repair, which resulted in a lower than projected number of transformers being repaired during 2015.

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

Project O&M was $162,656 or 12.5% lower than previously projected. The variance is primarily due to delays in obtaining equipment clearances (i.e., de-energize equipment) required for equipment repair, which resulted in a lower than projected number of transformers being repaired during 2015.

Project 22. Pipeline Integrity Management

Project O&M was $199,797 or 23.4% higher than previously projected. The variance is primarily due to unplanned inspection/repair digs that had to be performed after the detection of potential integrity anomalies identified during the scheduled pipeline inspection of the Martin Terminal 18-inch line. Regulations require that confirmatory digs and any needed repairs be performed expeditiously and no later than 180 days following detection of potential integrity anomalies.

Project 23. Spill Prevention, Control & Countermeasures (“SPCC”)

Project O&M was $165,181 or 17.8% lower than previously projected. The variance is primarily due to fewer spills than projected.

Project 28. CWA 316(b) Phase II Rule

Project O&M was $249,677 or 37.2% lower than previously projected. The variance is primarily due to the Florida Department of Environmental

Protection's ("FDEP") delaying required studies that FPL is planning to perform at applicable facilities to demonstrate compliance with the Rule. The FDEP has delayed the start dates for the studies until the effective date of each site's National Pollutant Discharge Elimination System ("NPDES") renewal permit. This resulted in much of the projected study cost being deferred to future years.

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

Project O&M was $355,528 or 7.6% higher than previously projected. The variance is primarily due to the installation of a limestone handling area windscreen, whose need was not known at the time of the actual/estimated filing. The variance was also due to higher than projected property insurance costs and higher than projected limestone consumption costs for operation of the Flue Gas Desulfurization system. These variances were partially offset by lower than projected ammonia consumption by the Scherer 4 Selective Catalyst Reduction unit.

Project 37. DeSoto Next Generation Solar Energy Center

Project O&M was $124,991 or 11.7% lower than previously projected. The variance is primarily due to lower than projected payroll expense that resulted from delays in filling a vacant position. The vacant position has now been filled. Additionally, lower than projected costs of materials resulting from favorable competitive bids also contributed to lower than projected project expenses.

Project 39. Martin Next Generation Solar Energy Center

Project O&M was $404,008 or 11.0% higher than previously projected. The variance is primarily due to accelerated purchases of Heat Transfer Fluid and parts required to conduct solar repairs during the January and February 2016 planned outages. Additional cost increases also occurred as a result of solar field Heat Collection Element tube weld repairs due to Fusion Weld failures during solar field operation, and from the unplanned installation of support brackets at the ball joint locations within the Solar Field Loops to reduce the stress on the joints, which reduces the occurrence of mechanical failures of the joints.

Project 40. Greenhouse Gas Reduction Program

Project O&M was $55,000 or 69.8% lower than previously projected. The variance is primarily due to lower than projected costs for participation in the FDEP stakeholder process for development of a State Implementation Plan ("SIP") for the U.S. Environmental Protection Agency's Clean Power Plan ("CPP"), which was anticipated to occur after the CPP became final. FPL projected a cost of $70,000 for consultant work to analyze the options and effects on customers that would be considered during the FDEP's development of the SIP. On August 13, 2015, a coalition of 15 Attorneys General that included Florida filed a petition in the U.S. Court of Appeals for the D.C. Circuit to postpone the CPP deadlines. In response to Florida's participation in the petition the FDEP suspended outreach efforts for development of the SIP. On February 15, 2016, the U.S. Supreme Court issued a stay on the effectiveness of the CPP until the D.C. Circuit issues an opinion on the CPP rule. The FDEP will likely suspend efforts on the development of the CPP SIP until the Court issues its opinion.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project O&M was $15,251,920 or 36.8% lower than previously projected. The primary cause of the variance was the identification and implementation of a more effective sediment removal methodology than FPL originally anticipated using.

Project 45. 800 MW Unit ESP

Project O&M was $280,392 or 26.0% lower than previously projected. The variance is primarily due to the Manatee Site operating fewer hours on fuel oil than projected. Lower operation on fuel oil resulted in reduced ESP maintenance requirements.

Project 46. St. Lucie Cooling Water Discharge Monitoring

Project O&M was $115,007 or 101.8% higher than previously projected. The variance is primarily due to the St. Lucie Plant having outstanding charges of $123,000 for 2014 expenses that were paid in July 2015.

Project 50. Steam Electric Effluent Guidelines Revised Rules

Project O&M was $119,528 or 30.2% higher than previously projected. The variance is primarily due to FPL's share of higher than projected costs associated with required studies to determine the Rule's impact on Plant Scherer.

Project 54. Coal Combustion Residuals ("CCR")

Project O&M was $109,417, whereas no expenditures were projected for 2015. The variance is due to accelerated implementation of St John's River Power Park's ("SJRPP") plan to ensure that compliance dates are met and that CCR rule application is restricted to applicable units. Costs were incurred for engineering evaluations and modifications to the settling basins at SJRPP, where ash contact water goes. Initially, the basins were thought to require either upgrades or closure. The engineering studies determined that these basins did not meet the CCR rule's definition of ash management units due to the de minimis quantity of ash concentration.

Costs were also incurred for engineering evaluations of the existing well network and installation of additional wells to meet the CCR rule's criteria and ensure the October 2017 deadline is met for completing and evaluating the required eight sampling events for continued use of the landfill.

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. 160007-EI

AUGUST 4, 2016

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 2016 through December 2016.

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 2016 through December 2016.
- 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 39) reflects return on capital investments and depreciation by project. Pages 40 through 43 provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each Capital Investment Project.
- Form 42-9E 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 2016 through December 2016.

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 2016 through December 2016 is an under-recovery, including interest, of $1,973,599 (Appendix I, Page 2, Line 5 plus Line 6). This Actual/Estimated True-up amount consists of actual data for January 2016 through June 2016 and revised estimates for July 2016 through December 2016, 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. Yes.

Q. How do the Actual/Estimated project expenditures for January 2016 through December 2016 compare with original projections?

A. Form 42-4E (Appendix I, Page 4) shows that total O&M project costs were $3,193,947 lower than projected, while Form 42-6E (Appendix I, Page 8) shows that total capital investment project costs were $86,876 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 2016 Actual/Estimated period are provided on Form 42-8E (Appendix I, Pages 12 through 39). Explanations for components of individual project variances are provided below.

O&M Project Variances

Project 1. Air Operating Permit Fees

Project expenditures were $58,799 or 21.5% higher than previously projected. The variance is primarily due to the inadvertent omission from the 2016 projections filing of air operating permit fee estimates for Plant Scherer. This increase is partially offset by lower than projected emissions, which are the basis for the fees calculation.

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

Project expenditures were $59,978 or 28.1% higher than previously projected. The variance is primarily related to accelerating into 2016 a required Internal API Inspection at the Lauderdale Jet A storage tank that was performed earlier than planned as a result of the Lauderdale Peaker Project. The Peaker project required the tank to be emptied in order to convert from Jet A to Ultra-Low Sulfur Diesel fuel, which allowed the Internal API Inspection to be most economically performed at that time. This increase was partly offset by deferral of the Martin plant start-up diesel tank coating touch-up project, which, due to the good condition of the coating, will not be needed at this time.

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

Project expenditures were $57,842 or 5.7% lower than previously projected. The variance is primarily due to delays in obtaining equipment clearances (i.e., de-energize equipment) required for equipment repair, which is resulting in a lower than projected number of transformers being repaired during 2016.

Project 22. Pipeline Integrity Management

Project expenditures were $86,413 or 44.0% higher than previously projected. The variance is primarily due to a change in excavation methodology used to perform pipeline repairs that were discovered by the In-Line Inspector vendor. In order to limit the size of the excavation to avoid potential undermining and impacts to the Highway US 1 roadbed, a vacuum excavation methodology (soft dig) was used (versus planned excavation by back-hoe), which allowed for a smaller affected area of excavation.

Project 23. SPCC – Spill Prevention, Control & Countermeasures

Project expenditures were $77,867 or 8.0% lower than previously projected. In April 2016, FPL identified that a portion of a contractor's charges should have been allocated to a non-ECRC account in 2015 and 2016. This resulted in incorrect charges to the ECRC account of $70,024 in 2015 and $25,366 in 2016. A Correction & Adjustment was completed in May 2016, and all charges are being properly allocated.

Project 24. Manatee Reburn

Project expenditures were $180,000 or 93.9% higher than previously projected. The variance is primarily related to the reclassification from Capital to O&M of costs associated with upgrading gas burner valves at Manatee Unit 2. The project to upgrade the valves was originally projected to be Capital, however it was subsequently determined that the small magnitude of the expenditure required expensing the cost.

Project 28. CWA 316(b) Phase II Rule (currently referred to as "316(b) Existing Facilities Rule")

Project expenditures were $363,382 or 69.8% higher than previously projected. The variance is primarily due to the need for more biological sampling than anticipated. Projections were based on conducting monthly sampling events, which was the minimum frequency required by the 316(b) Rule. However, negotiations with the FDEP that occurred after the projections were filed resulted in a revised requirement for two sampling events per month.

Project 31. CAIR (currently referred to as "CSAPR")

Project expenditures were $1,296,195 or 18.1% lower than previously projected. The variance is primarily due to lower than projected generation at Scherer and SJRPP as a result of lower than projected system dispatch of the coal units. This resulted in lower than projected consumption of ammonia required for NOx control at Scherer and SJRPP, and lower than projected consumption of limestone required for SO2 control at the Scherer FGD. In addition, there was a reduction in project expenses due to the change-over to a new demineralized water system at the Manatee Plant.

Project 33. MATS

Project expenditures were $537,271 or 17.8% lower than previously projected. The variance is primarily due to lower than projected consumption of powder activated carbon required for mercury (Hg) control at Plant Scherer as a result of lower than projected generation. In addition, at SJRPP there was lower than projected calcium bromide injection due to improved Hg removal efficiency in the FGD process associated with a change in limestone quality and pH management.

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

Project expenditures were $152,515 or 17.0% lower than previously projected. The variance is primarily due to the identification and implementation of a performance based vegetation management program resulting from Project Momentum.

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

Project expenditures were $91,218 or 31.6% lower than previously projected. The variance is primarily due to the identification and implementation of a performance based vegetation management program resulting from Project Momentum.

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

Project expenditures were $53,751 or 1.4% lower than previously projected. The variance is primarily due to lower contractor costs associated with routine maintenance of the solar facility. A new contractor was selected in June using the bidding process, which will lower costs through the end of the year.

Project 40. Greenhouse Gas Reduction Program

Project expenditures were $51,500 or 65.2% lower than previously projected. The variance is primarily due to lower than projected consultant and legal costs, which were anticipated to occur in response to the FDEP's development of Florida's State Implementation Plan ("SIP") to implement the EPA's Clean Power Plan ("CPP") Rule. However, development of the SIP has been delayed as a result of the United States Supreme Court's ruling to stay the final CPP pending completion of all legal proceedings related to challenges to the rule.

Project 41. Manatee Temporary Heating Systems

Project expenditures were $1,616,863 or 85.7% lower than previously projected. The variance is primarily due to a delay in the relocation of the Cape Canaveral Clean Energy Center ("CCEC") manatee heaters. The CCEC did not receive the necessary permits to conduct this work in 2016 so the project was delayed until 2017. In addition, the manatee heating system at Pt. Everglades was not operated as anticipated due to a mild winter; therefore O&M costs were lower than projected. The Pt. Everglades Clean Energy Center's temporary manatee heating system has been retired.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project expenditures were $281,322 or 1.0% lower than previously projected. The variance is primarily attributed to less sediment removal performed in 2016 than originally planned and not incurring costs for delivering storm water from the L-31 Canal. The variance is partially offset by the re-classification of Recovery Well System costs from Capital to O&M. These wells are required by the Miami Dade Consent Agreement and used to halt and reduce the size of the hypersaline plume to the limits of FPL Property. Additionally, costs were not included in the original projection to comply with the Miami Dade County Consent Agreement that is discussed further in FPL witness LaBauve's testimony.

Project 45. 800 MW Unit ESP

Project expenditures were $228,874 or 19.0% lower than previously projected. The variance is primarily due to the Manatee 800 MW units generating for fewer hours than projected on fuel oil this Spring. These changes resulted in reduced maintenance requirements and, therefore, lower than projected costs.

Project 50. Steam Electric Effluent Limitation ("ELG") Guidelines

Project expenditures were $514,566 higher than previously projected. The variance is primarily due to the engineering analysis of alternatives and the development of pilot systems for water treatment design criteria to comply with the ELG specifications at Plant Scherer. Subsequent to its projection filing, FPL was informed by the Scherer operating agent, Georgia Power Corporation, that additional expenses for development of the ELG compliance strategy would be incurred in 2016-2019.

Additionally, O&M costs associated with restoration of the FGD return water and reclaim slurry systems at SJRPP were incurred. Projections for this work were not available when the 2016 projections were filed last Fall.

Capital Project Variances

Project 21. St. Lucie Turtle Nets

Project depreciation and return on investment were $77,244 or 9.9% higher than previously projected. The variance is primarily attributed to vendor charges that were not anticipated at the time the original estimates were filed.

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

Project depreciation and return on investment were $296,197 or 16.1% lower than previously projected. The variance is primarily attributed to a delay in the 2015 in-service date of the Pt. Everglades Terminal Secondary Containment for Double Wall Piping Project until February of 2016. This Project also was completed at a cost that was lower than forecast.

Project 31. **CAIR (currently referred to as "CSAPR")**

Project depreciation and return on investment were $255,517 or 0.5% higher than previously projected. The variance is primarily attributed to higher than projected overhaul repair costs for FGD pumps, motors and gearboxes at Plant Scherer incurred during the 2016 planned Spring overhaul. Additionally, the operating agent reclassified common site restoration costs to unit specific charge locations as part of the final unitization process.

Project 33. **MATS**

Project depreciation and return on investment were $67,081 or 0.6% lower than previously projected. The variance is primarily attributed to the decision of the operating agent to suspend the installation of the Scherer Unit 4 calcium bromine injection system pending a re-evaluation of the compliance method.

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

Project depreciation and return on investment were $169,968 or 0.4% higher than previously projected. The variance is primarily attributed to higher than projected costs associated with the Solar Control System Upgrade Project. The original project scope was increased to improve heat rate and reliability and reduce startup fuel consumption. The variance is partially offset by the retirement of Martin Solar mirrors, heat collection elements and piping.

Project 41. **Manatee Temporary Heating System**

Project depreciation and return on investment were $205,291 or 45.8% lower than previously projected. The variance is primarily attributed to the retirement of the temporary manatee heaters at Pt. Everglades Clean Energy Center after it went into service.

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

Project depreciation and return on investment were $119,400 or 11.9% lower than previously projected. The variance is primarily attributed to the re-classification of Recovery Well System costs from Capital to O&M. These wells are required by the Miami Dade County Consent Agreement and are used to halt and reduce the size of the hypersaline plume to the limits of FPL Property. Additionally, there were lower costs than originally projected for the Upper Floridan Aquifer wells, and the in-service date for one Floridan well changed from December, 2016 to July, 2017.

Project 45. 800 MW ESP

Project depreciation and return on investment were $57,509 or 0.2% higher than previously projected. The variance is primarily attributed to a change in the in-service date for the Manatee Units 1 & 2 inverters and HMI interface, and the Service Air Water Line, from April, 2016 to October, 2015. This change increased the beginning plant in service balance for 2016. The variance was partially offset by the reclassification of the Manatee Unit 2 Gas Valves Project from Capital to O&M.

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. 160007-EI

SEPTEMBER 2, 2016

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 2017 through December 2017 period. My testimony also provides a revised 2016 actual/estimated true-up amount, which includes updated 2016 cost projections associated with FPL's existing Turkey Point Cooling Canal Monitoring Plan ("TPCCMP") project resulting from recent developments that have occurred since FPL's August 4, 2016 actual/estimated true-up filing. Finally, my testimony identifies issues from FPL's current base rate proceeding in Docket No. 160021-EI that may impact the ECRC beginning in 2017.

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 any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- Exhibit TJK-3 provides the calculation of the revised 2016 actual/estimated true-up amount. These schedules are included in Appendix I.
- Exhibit TJK-4 provides the calculation of FPL's proposed ECRC factors for the period January 2017 through December 2017. FPL's proposed factors are based on the change in cost allocation methodology that FPL has proposed in its current rate case proceeding in Docket No. 160021-EI. These schedules are included in Appendix II.
- Exhibit TJK-5 provides the calculation of 2017 ECRC factors based on the currently approved 12 CP and 1/13th cost allocation methodology. These schedules are included in Appendix III.

Q. Why has FPL revised its 2016 actual/estimated true-up amount that was filed on August 4, 2016?

A. As discussed in the direct testimony of FPL witness Randall LaBauve, FPL is updating its 2016 cost projections associated with its existing TPCCMP project to reflect significant developments that have occurred since FPL's August 4, 2016 filing with respect to the regulatory requirements that the project addresses. FPL is presenting these updated cost projections consistent with the Commission's direction that utilities present the most current information available for the purpose of determining adjustment clause factors each year.

Q. Please describe the schedules that are provided in Appendix I.

A. Appendix I contains the schedules from FPL's August 4, 2016 actual/estimated true-up filing that have been revised to include updated costs associated with FPL's TPCCMP project. Forms 42-1E through 42-3E provide the calculation and summary of the revised 2016 actual/estimated true-up under-recovery amount of $6,424,842 and associated interest. Form 42-4E provides a revised O&M variance schedule to reflect updated expenses for the TPCCMP project for the 2016 actual/estimated period. Form 42-5E provides monthly expenses for O&M projects and the calculation of the jurisdictional O&M amount for the actual/estimated period. This schedule has been revised to include updated TPCCMP project cost estimates for the period July 2016 through December 2016. Capital costs associated with the TPCCMP project for the 2016 period were not revised from those provided in the August 4, 2016 filing, as these costs are associated with the Floridan wells and were not impacted by recent developments.

Q. Please explain why the cost of the Recovery Well System is recorded as O&M.

A. Under ASC 410-30 – Environmental Obligations, the Recovery Well System is considered an environmental remediation cost. ASC 410-30 obligations typically are incurred in the conduct of remediation and are therefore generally expensed. Capitalization of the Recovery Well System or a portion of the system may be appropriate, but additional analysis of that activity as it relates to the capitalization threshold under this standard is required. At present, FPL has not conducted this analysis.

Q. Please describe the schedules that are provided in Appendix II.

A. Forms 42-1P through 42-8P provide the calculation of ECRC factors for the period January 2017 through December 2017 that FPL is requesting this Commission to approve. These factors were calculated based on FPL's proposed cost allocation methodology of 12 CP and 25%.

Form 42-1P (Appendix II, Page 1) provides a summary of projected environmental costs being requested for recovery for the period January 2017 through December 2017. Total environmental requirements, adjusted for revenue taxes, are $245,116,908 (Appendix II, Page 1, Line 5) and include $256,332,720 of environmental project jurisdictional revenue requirements for the January 2017 through December 2017 period (Appendix II, Page 1, Line 1c) increased by the revised actual/estimated true-up under-recovery of $6,424,842 for the January 2016 through December 2016 period (Appendix II, Page 1, Line 2), and decreased by the final true-up over-recovery of $17,817,012 for the January 2015 through December 2015 period (Appendix II, Page 1, Line 3).

Form 42-2P (Appendix II, 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 $101,558,567 for the period January 2017 through December 2017.

Form 42-3P (Appendix II, 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 $168,196,335 for the period January 2017 through December 2017.

Form 42-4P (Appendix II, Pages 6 through 38) presents the calculation of depreciation expense and return on capital investment for each project for the projected period.

Form 42-5P (Appendix II, Pages 39 through 123) provides the description and progress of approved environmental projects included in the projected period.

Form 42-6P (Appendix II, Page 124) 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.

Form 42-7P (Appendix II, Page 125) presents the calculation of the proposed 2017 ECRC factors by rate class based on the 12 CP and 25% cost allocation methodology.

Form 42-8P (Appendix II, Page 126) 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 2017 through December 2017. 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 2016 Earnings Surveillance Report.

Q. Please describe the schedules that you have provided in Appendix III.

A. Appendix III contains the calculation of 2017 ECRC factors based on the currently approved cost allocation methodology of 12 CP and 1/13th.

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

A. Yes.

PENDING BASE RATE CASE ISSUES IMPACTING THE ECRC CLAUSE

Q. Is FPL proposing an adjustment in its current base rate proceeding in Docket No. 160021-EI that would impact the allocation of 2017 ECRC cost projections to customer classes?

A. Yes. As explained in the direct testimony of Renae B. Deaton filed in Docket No. 160021-EI on March 15, 2016, FPL is proposing to utilize a 12 CP and 25% methodology for allocating production plant, rather than the 12 CP and 1/13th method used in prior rate cases. Transmission costs classified to demand are allocated based on their 12 CP contributions, adjusted for losses.

Q. Has FPL calculated 2017 ECRC factors based on the proposed change in allocation methodology?

A. Yes. FPL is requesting the Commission to approve its 2017 ECRC factors for customer classes that are based on allocating demand-related costs using the 12 CP and 25% methodology. The 2017 ECRC factors calculated based on this cost allocation methodology are included in Exhibit TJK-4, which is provided in Appendix II. In the alternative, FPL requests the Commission to approve 2017 ECRC factors based on the current 12 CP and 1/13th methodology. These factors are included in Exhibit TJK-5, which is provided in Appendix III.

Q. Is FPL proposing any new rate schedules in its current base rate proceeding?

A. Yes. As discussed in the direct testimony of Tiffany C. Cohen filed in Docket No.

160021-EI on March 15, 2016, FPL is proposing two new lighting rate schedules: Metered Customer-Owned Street Lights (SL-1M) and Metered Traffic Signals (SL-2M).

Q. Has FPL calculated ECRC factors for the proposed metered lighting rate schedules?

A. Yes. The ECRC factors for the proposed new metered lighting rate schedules are included in Forms 42-6P and 42-7P in Exhibits TJK-4 and TJK-5.

Q. Is FPL proposing an adjustment in its base rate proceeding to move costs currently in base rates to the ECRC clause?

A. Yes. As explained in the direct testimony of Kim Ousdahl, filed in Docket No. 160021-EI on March 15, 2016, presently, a small number of approved ECRC projects classified as in-construction or CWIP remain in base rates. FPL believes that moving these costs from base rates to the ECRC clause is appropriate in order to recover all ECRC related costs through the ECRC clause.

Q. Has FPL included this proposed adjustment in the calculation of its 2017 ECRC factors?

A. No. FPL has not included this adjustment in the calculation of its 2017 ECRC factors. Should the Commission approve this adjustment in Docket No. 160021-EI, FPL will reflect this adjustment in the true-up process for 2017.

Q. Is FPL proposing an adjustment in its base rate proceeding to implement a capital recovery schedule applicable to the ECRC clause?

A. Yes. As proposed in the direct testimony of Keith Ferguson, filed in Docket No.

160021-EI on March 15, 2016, FPL requested that the Commission approve recovery of certain ECRC project costs based on the capital recovery schedule filed in that docket.

Q. **Has FPL included the proposed capital recovery schedule in its 2017 projections?**

A. No. FPL has not included the proposed capital recovery schedule in the calculation of its 2017 ECRC factors. Should the Commission approve the proposed capital recovery schedule in Docket No. 160021-EI, FPL will reflect this adjustment in the routine true-up process for 2017.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

CHRISTOPHER MENENDEZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 160007-EI

April 1, 2016

Q. Please state your name and business address.

A. My name is Christopher Menendez. 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, LLC ("DEF" or the "Company"), as Rates and Regulatory Strategy Manager.

Q. What are your responsibilities in that position?

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

Q. Please describe your educational background and professional experience.

A. I joined the Company on April 7, 2008 as a Senior Financial Specialist in the Florida Planning & Strategy group. In that capacity, I supported the development of long-term financial forecasts and the development of current-year monthly earnings and cash flow projections. In 2011, I accepted a position as a Senior Business Financial Analyst in the Power Generation Florida Finance organization. In that capacity, I provided accounting and financial analysis support to various generation facilities in DEF's Fossil fleet. In 2013, I accepted a position as a Senior Regulatory Specialist. In that capacity, I supported the preparation of testimony and exhibits for the Fuel Docket as well as other Commission Dockets. In October 2014, I was promoted to my current position. Prior to working at DEF, I was the Manager of Inventory Accounting and Control for North American Operations at Cott Beverages. In this role, I was responsible for inventory-related accounting and inventory control functions for Cott-owned manufacturing plants in the United States and Canada. I received a Bachelor of Science degree in Accounting 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?

A. Yes, I have previously provided testimony in the Fuel and Capacity Cost Recovery Clause docket detailing DEF's True-up, Actual/Estimated, and Projected fuel and capacity costs.

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 2015 - December 2015.

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

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

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

- Form 42-1A: Final true-up for the period January 2015 - December 2015.
- 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 1-19: 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.___ CAM-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. The Company relies on the information included in this testimony in the conduct of its affairs.

Q. What is the final true-up amount DEF is requesting for the period January 2015 - December 2015?

A. DEF requests approval of an over-recovery amount of $1,171,886 for the year ending December 31, 2015. 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 2015 - December 2015 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 $1,951,488 reflected on Line 3 of Form 42-1A, as the adjusted net true-up amount for the period January 2015 - December 2015. This amount is the difference between an actual over-recovery amount of $1,171,886 and an actual/estimated under-recovery of $779,602 for the period January 2015 - December 2015, as approved in Order PSC-15-0536-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 2015 - December 2015 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 $1,874,578 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, Timothy Hill, and Patricia Q. West.

Q. How did actual capital recoverable expenditures for January 2015 - December 2015 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 $133,942 lower 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 1-19. Explanations associated with variances are contained in the direct testimonies of Michael Delowery, Timothy Hill, Jeffrey Swartz and Patricia West.

Q. Please explain the variance between actual project expenditures and the Actual/Estimated projections for the SO_2/NOx Emissions Allowance (Project 5).

A. The O&M variance is $286,265 higher than projected due to the purchase of seasonal NOx allowances.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

CHRISTOPHER A. MENENDEZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 160007-EI

August 4, 2016

Q. Please state your name and business address.

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

Q. Have you previously filed testimony before this Commission in Docket No. 160007-EI?

A. Yes, I provided direct testimony on April 1, 2016.

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 2016 through December 2016. I also explain the variance between 2016 actual/estimated cost projections versus original 2016 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. __CAM-3, which consists of PSC Forms 42-1E through 42-9E; and
2. Exhibit No. __CAM-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 2016 through December 2016.

Q. What is the actual/estimated true-up amount for which DEF is requesting recovery for the period of January 2016 through December 2016?

A. The 2016 actual/estimated true-up is an over-recovery, including interest, of $6,606,430 as shown on Form 42-1E, line 4. This amount is added to the final 2015 true-up over-recovery of $1,951,488 as shown on Form 42-2E, Line 7a, resulting in a net over-recovery of $8,557,918 as shown on Form 42-2E, Line 11. The calculations supporting the 2016 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 2016 through December 2016?

A. The capital structure, components and cost rates relied on to calculate the revenue requirement rate of return for the period January 2016 through December 2016 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 2016 through December 2016 compare with original projections?

A. Form 42-4E shows that total O&M project costs are estimated to be $3.4M lower than originally projected. This form also lists individual O&M project variances. Explanations for these variances are included in the direct testimonies of Timothy Hill, Jeffrey Swartz and Patricia Q. West, except for Emission Allowances which is below.

Q. Please explain the variance between actual/estimated project expenditures and original projections for SO2/NOx Program (Project 5) for the period January 2016 through December 2016?

A. SO2 and NOx expenses are estimated to be approximately $46k or 41% lower than originally projected due to lower than projected SO2 allowance expense.

Q. How do estimated/actual capital recoverable costs for January 2016 through December 2016 compare with DEF's original projections?

A. Form 42-6E shows that total recoverable capital costs are estimated to be approximately $458k or 2% lower than originally projected. This form also lists individual project variances. The return on investment, depreciation expense and property taxes for each project for the actual/estimated period are provided on Form 42-8E, pages 1 through 18. Explanations for these variances are included in the direct testimonies of Michael Delowery, Mr. Hill, Mr. Swartz and Ms. West.

Q. Is DEF retiring any ECRC projects?

A. Yes. DEF has retired the peaking units at the Turner CT plant. With this retirement, the Above Ground Tank Secondary Containment (Project 4.1a) and CAIR CT (Project 7.2g) assets are also retired, effective March 31, 2016. DEF will also be retiring the Anclote-Bartow Pipeline and with this retirement, the Pipeline Leak Detection (Project 3.1b), Pipeline Controls Upgrade (Project 3.1c) and Control Room Management (Project 3.1d) will also be retired, effective August 31, 2016. The Alderman Road Fence (Project 3.1a) will remain in-service to support ongoing monitoring activities; DEF expects this project to be retired in 2017.

Q. How does DEF propose to treat unrecovered ECRC costs of the Above Ground Tank Secondary Containment and CAIR CT projects?

A. Consistent with the Commission's treatment of the NOx Allowances, as approved in Commission Order No. PSC-11-0553-FOF-EI, in Docket No. 110007-EI and the Crystal River Thermal Discharge Compliance Project, as approved in Commission Order No. PSC-13-0381-PAA-EI, in Docket No. 130091-EI, DEF proposes that the Commission approve treating these costs as a regulatory asset as of April 1, 2016 and allow DEF to amortize them equally over approximately three years until fully recovered in 2019. The unamortized investment balance should earn a return at DEF's WACC until such time as the investment is fully recovered.

The proposed amortization of the Above Ground Secondary Containment and CAIR CT assets will have no effect on 2016 rates. Any over/under-recovery will be part of the normal true-up process in the annual ECRC proceedings. Unrecovered Above Ground Secondary Containment costs are approximately $1.6M as of March 31, 2016; unrecovered CAIR CT costs are approximately $116k as of March 31, 2016.

Q. How does DEF propose to treat unrecovered ECRC costs of the Pipeline Integrity Management Projects?

A. Consistent with the Commission's treatment of the NOx Allowances, as approved in Commission Order No. PSC-11-0553-FOF-EI, in Docket No. 110007-EI and the Crystal River Thermal Discharge Compliance Project, as approved in Commission Order No. PSC-13-0381-PAA-EI, in Docket No. 130091-EI, DEF proposes that the Commission approve treating these costs as a regulatory asset as of September 1, 2016 and allow DEF to amortize them equally over approximately three years until fully recovered in 2019. The unamortized investment balance should earn a return at DEF's WACC until such time as the investment is fully recovered.

The proposed amortization of the Pipeline Integrity Management assets will have no effect on 2016 rates. Any over/under-recovery will be part of the normal true-up process in the annual ECRC proceedings. Unrecovered Pipeline Leak Detection costs are projected to be approximately $939k as of August 31, 2016, unrecovered Pipeline Controls Upgrade costs are projected to be approximately $716k as of August 31, 2016 and Control Room Management costs are projected to be approximately $114k as of August 31, 2016.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

CHRISTOPHER A. MENENDEZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 160007-EI

August 31, 2016

Q. Please state your name and business address.

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

Q. Have you previously filed testimony before this Commission in Docket No. 160007-EI?

A: Yes. I provided direct testimony on April 1, 2016 and August 4, 2016.

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 2017 through December 2017. My testimony also addresses capital and O&M expenses for DEF's environmental compliance activities for the year 2017.

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

The individuals listed below are co-sponsors of Forms 42-5P pages 1-4 and 6-23 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 8-20.
- Mr. Swartz and Ms. West will co-sponsor Form 42-5P page 7.
- Mr. Swartz will co-sponsor Form 42-5P pages 21 and 22.
- Mr. Hill will co-sponsor Form 42-5P page 23.

Q. Please summarize your testimony.

A. My testimony supports the approval of an average ECRC billing factor of 0.147 cents per kWh which includes projected jurisdictional capital and O&M revenue requirements for the period January 2017 through December 2017 of approximately $66.2 million associated with a total of 18 environmental projects, and a true-up over-recovery provision of approximately $8.6 million from prior periods. My testimony also supports that projected environmental expenditures for 2017 are appropriate for recovery through the ECRC.

Q. What is the total recoverable revenue requirement for the period January 2017 through December 2017?

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is approximately $57.7 million as shown on Form 42-1P line 5 of Exhibit No. __(CAM-5).

Q. What is the total true-up to be applied for the period January 2017 through December 2017?

A. The total true-up applicable to this period is an over-recovery of approximately $8.6 million. This amount consists of the final true-up over-recovery of approximately $2.0 million for the period January 2015 through December 2015, and an estimated true-up over-recovery of approximately $6.6 million for the current period of January 2016 through December 2016. The detailed calculation supporting the 2016 estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. __ (CAM-3) filed with the Commission on August 4, 2016.

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

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

The Substation and Distribution System 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.

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 Effluent Limitations Guidelines Program (Project 15.1) was previously approved in Order No. PSC-13-0606-FOF-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.

The Coal Combustion Residual (CCR) Rule was previously approved in Order No. PSC-15-0536-FOF-EI.

Q. Is DEF projecting to retire any ECRC projects?

A. Yes. Consistent with my August 4, 2016 testimony, DEF expects to retire the Alderman Road Fence (Project 3.1a) in July 2017, thus completing the retirement of the Anclote-Bartow Pipeline projects. The unrecovered Alderman Road Fence costs are projected to be approximately $24k as of July 31, 2017.

Q. How does DEF propose to treat unrecovered ECRC costs of the Alderman Road Fence (Project 3.1a)?

A. Consistent with my August 4, 2016 testimony and the Commission's treatment of NOx Allowances and the Crystal River Thermal Discharge Compliance project approved in Commission Order Nos. PSC-11-553-FOF-EI and PSC-13-0381-PAA-EI, respectively, DEF proposes that the Commission approve treating these costs as a regulatory asset as of August 1, 2017 and allow DEF to amortize them equally over a 24-month period, which approximately corresponds with the remaining period of the Anclote-Bartow Pipeline projects; this is intended to align the amortization of all the Anclote-Bartow Pipeline projects. The unamortized balance should earn a return at DEF's WACC until such time as the investment is fully recovered. The proposed amortization is included in DEF's 2017 Projected rates.

Q. What capital structure, components and cost rates did DEF rely on to calculate the revenue requirement rate of return for the period January 2017 through December 2017?

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 2016 Earnings Surveillance Report Weighted Average Cost of Capital. These rates are shown on Form 42-8P, Exhibit No. ___(CAM-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 2017?

A. Yes. Form 42-2P of Exhibit No. __ (CAM-5) summarizes recoverable jurisdictional O&M cost estimates for these projects of approximately $40.9 million.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2017?

A. Yes. Form 42-3P of Exhibit No. __ (CAM-5) summarizes recoverable jurisdictional capital cost estimates for these projects of approximately $25.4 million. Form 42-4P pages 1 through 17 show 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 23 of Exhibit No. __ (CAM-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 2017?

A. The total jurisdictional capital and O&M costs to be recovered through the ECRC are approximately $66.2 million. The costs are calculated on Form 42-1P line 1c of Exhibit No. __ (CAM-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. __(CAM-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 2017 ECRC billing factors by the various rate classes and delivery voltages?

A. The calculation of DEF's proposed ECRC factors for 2017 customer billings is shown on Form 42-7P in Exhibit No. __(CAM-5) as follows:

RATE CLASS	ECRC FACTORS 12CP & 1/13AD
Residential	0.151 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.147 cents/kWh
@ Primary Voltage	0.146 cents/kWh
@ Transmission Voltage	0.144 cents/kWh
General Service 100% Load Factor	0.139 cents/kWh
General Service Demand	
@ Secondary Voltage	0.144 cents/kWh
@ Primary Voltage	0.143 cents/kWh
@ Transmission Voltage	0.141 cents/kWh
Curtailable	
@ Secondary Voltage	0.168 cents/kWh
@ Primary Voltage	0.166 cents/kWh
@ Transmission Voltage	0.165 cents/kWh
Interruptible	
@ Secondary Voltage	0.137 cents/kWh
@ Primary Voltage	0.136 cents/kWh
@ Transmission Voltage	0.134 cents/kWh
Lighting	0.144 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 2017 and continue through the last bill group for December 2017.

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. 160007-EI

April 1, 2016

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 Business Services 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 Duke Energy Florida's ("DEF") 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 24 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 2015 – December 2015.

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 fan modification work was completed on May 22, 2014 and November 17, 2014, respectively. Total actual project cost as of 2015 year end is approximately $134 million.

Q. How did actual project expenditures for January 2015 – December 2015 compare to actual/estimated projections for the Anclote Gas Conversion Project (Project 17.1)?

A. The Anclote Gas Conversion capital variance is $758,173 or 149% lower than projected due to a vendor billing adjustment and release of retention money.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>MICHAEL R. DELOWERY</u>

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 160007-EI

August 4, 2016

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. 160007-EI?

A: Yes, I provided direct testimony on April 1, 2016.

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 2016 actual/estimated cost projections and original 2016 cost projections for environmental compliance costs associated with DEF's Mercury and Air Toxics Standards (MATS) - Anclote Gas Conversion Project (Project 17.1).

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 2016 through December 2016.

A. There were no 2016 projected Capital or O&M costs for MATS – Anclote Gas Conversion Program. The Capital variance of $139k is due to retainage adjustments stemming from contractor retained payments charged to the project in 2016. No further charges are expected.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>TIMOTHY HILL</u>

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 160007-EI

April 1, 2016

Q. Please state your name and business address.

A. My name is Timothy Hill. My 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 Corporation ("Duke Energy") as Regional General Manager for the Coal Combustion Products ("CCP") Group - Operations & Maintenance. Duke Energy Florida, LLC ("DEF" or the "Company") is a fully owned subsidiary of Duke Energy.

Q: What are your responsibilities in that position?

A: I am responsible for oversight of the operation and maintenance of all CCP facilities in the Western Carolinas and Florida, including the CCP facility at the Crystal River Energy Center. This includes operating and maintaining all CCP facilities in compliance with state and federal regulations. The Operations and Maintenance group at each station maintains accountability for overall CCP facility performance which requires close collaboration with other Duke Energy CCP organizations such as Project Implementation, Engineering, and Facility Closure. The Company relies on my opinions and information I provide when making decisions regarding the CCP facilities under my supervision.

Q: Please describe your educational background and professional experience.

A: I have a Bachelor of Science degree in Nuclear Engineering from the University of Florida and a Master of Science degree from the University of Central Florida. I have 13 years of experience in the power generation industry including positons as an Engineering Manager, a Maintenance Manager, and a Plant Manager within Duke Energy's fossil fleet, and as Fleet and Harris Station Maintenance Manager in Duke Energy's nuclear fleet. Prior to joining Duke Energy I was employed by Delta Air Lines as a General Manager in Engineering and Maintenance and prior to that I served 21 years as a commissioned officer in the U.S. Navy, serving in the nuclear fleet. In November of 2014, I began my current role as CCP Regional General Manager.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an update on DEF's 2015 Coal Combustion Residual ("CCR") Rule compliance activities and associated 2015 compliance costs for which the Company seeks recovery through the Environmental Cost Recovery Clause ("ECRC").

Q. How did actual Capital project expenditures for the period January 2015 – December 2015 compare to actual/estimated Capital projections for the CCR Rule (Project 18)?

A. The CCR Rule capital variance is $1,535,570 or 96% lower than projected due to a change in DEF's expected 2015 CCR compliance activities associated with the Crystal River temporary gypsum pad and additional vegetation management requirements as explained in the August 31, 2015 Direct Testimony of Garry Miller in Docket No. 150007. DEF initially estimated $1.5M for a permanent fugitive dust control system at the temporary gypsum pad. After further analysis, DEF determined it would be unable to complete the project by the October 19, 2015 CCR compliance date and instead employed a temporary solution. DEF also determined that vegetation management compliance could be achieved without spending the $100k of capital included in the July 31, 2015 filing.

Q. How did actual O&M project expenditures for the period January 2015 – December 2015 compare to actual/estimated O&M projections for the CCR Rule (Project 18)?

A. The CCR O&M variance is $130,877 or 33% lower than projected. This is primarily due to lower than expected costs for engineering studies and vegetation management costs associated with the ash landfill and Flue Gas Desulfurization ("FGD") basins.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

TIMOTHY HILL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 160007-EI

August 4, 2016

Q. Please state your name and business address.

A. My name is Timothy Hill. My business address is 400 South Tryon Street, Charlotte, NC 28202.

Q. By whom are you employed?

A: I am employed by Duke Energy Corporation ("Duke Energy") as Regional General Manager for the Coal Combustion Products ("CCP") Group - Operations & Maintenance. Duke Energy Florida, LLC ("DEF" or the "Company") is a fully owned subsidiary of Duke Energy.

Q. Have you previously filed testimony before this Commission in Docket No. 160007-EI?

A: Yes, I provided direct testimony on April 1, 2016.

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 2016 actual/estimated cost projections and original 2016 cost projections for environmental compliance costs associated with DEF's Coal Combustion Residual ("CCR") Rule compliance project.

Q: Please explain the variance between actual/estimated project expenditures and original projections for CCR (Project 18) O&M for the period January 2016 through December 2016.

A: O&M expenditures for CCR are expected to be approximately $572k or 32% higher than originally projected due to increased cost based on competitive bidding for the dredging of the gypsum basin. There are also additional costs associated with developing a closure plan for the FGD blowdown ponds, as required for compliance with CCR rule.

Q: Please explain the variance between actual/estimated project expenditures and original projections for CCR (Project 18) capital for the period January 2016 through December 2016.

A: Capital expenditures for CCR are expected to be approximately $3.5M or 91% lower than originally projected because the temporary dust control measures were demonstrated to be appropriate to meet CCR Rule compliance and will be made permanent.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

TIMOTHY HILL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 160007-EI

August 31, 2016

Q. Please state your name and business address.

A. My name is Timothy Hill. My business address is 400 South Tryon Street, Charlotte, NC 28202.

Q. Have you previously filed testimony before this Commission in Docket No. 160007-EI?

A: Yes. I provided direct testimony on April 1, 2016 and August 4, 2016.

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 2017 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. __ (CAM-5) to Christopher A Menendez's direct testimony:

- 42-5P page 23 of 23 – Coal Combustion Residual Rule

Q: What are the CCR rule compliance activities and associated costs for which DEF is seeking recovery in 2017?

A: <u>Ash Landfill and Flue Gas Desulfurization Ponds O&M Costs</u>

Various maintenance and repair work is required for the CR ash landfill and FGD ponds to comply with the new rule. These include fixing ruts and animal burrows, vegetation management, erosion repairs, and inspections and maintenance to address accumulations in ash and gypsum handling/loading areas, including around silos, scales, and conveyors. Additionally the new rule requires annual inspections of the landfill and FGD ponds by qualified engineers. Total estimated O&M costs are $413k.

<u>Flue Gas Desulfurization (“FGD”) Blowdown Ponds</u>

DEF estimates $203k of capital expenditures to perform the required groundwater monitoring, which includes engineering, sampling, analysis, reporting, and drilling wells. Additionally, DEF will begin engineering, planning, and procurement in 2017 to prepare for closure of the FGD Blowdown Ponds starting in 2018.

Q. Are there any other CCR rule compliance activities and costs for which DEF expects to seek recovery in 2017?

A. DEF continues to evaluate the CCR rule to determine operating and cost impacts, and expects to incur costs in 2017 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, LLC

DOCKET NO. 160007-EI

April 1, 2016

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, LLC ("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 15 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 2015 - December 2015.

Q. How do actual O&M expenditures for January 2015 - December 2015 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 $1,685,589 or 6% lower than projected. This variance is primarily attributable to $427,978 lower than expected CAIR Crystal River Project 7.4 – Base costs, and $1,278,679 lower than expected CAIR-Crystal River Project 7.4 – Energy Costs.

Q: Please explain the variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Base for January 2015 - December 2015?

A: O&M costs for CAIR Crystal River Project – Base were $427,978 or 3% lower than projected primarily due to lower labor cost.

Q. Please explain the variance between actual project expenditures and the actual/estimated projections for CAIR Crystal River Project – Energy for the period January 2015 - December 2015?

A. O&M costs for CAIR Crystal River Project - Energy were $1,278,679 or 9% lower than forecasted primarily due to lower than projected generation, which resulted in reduced reagent expense of $522,250 for ammonia, $288,665 for limestone, and $481,423 for hydrated lime.

Q. How did actual O&M expenditures for January 2015 - December 2015 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 $460,083 or 12% higher than projected. The O&M variance is due primarily to an increase in the scope of performance testing. Test burns with alternative fuel were conducted in fall 2015 to confirm the expected benefits from Electrostatic Precipitator ("ESP") improvement projects and to evaluate unit performance in preparation for MATS compliance. Favorable 2015 test results allowed for the durations of the fuel burns to be extended in order to gain confidence in long-term operation with alternative fuel. The expanded scope completed in 2015 will be offset by a reduction in the costs for additional testing in 2016 by approximately 75%.

Q. How did actual capital expenditures for January 2015 - December 2015 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 $110,264 or 1% higher than projected due to an increase in scope of a Unit 2 ESP project. Hoppers in the "Old A/B

ESP" were replaced to provide structural stability for the mechanical stress associated with the hopper vibrators that were installed for MATS compliance in 2014.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 160007-EI

August 4, 2016

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. 160007-EI?

A: Yes, I provided direct testimony on April 1, 2016.

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 2016 actual/estimated cost projections and original 2016 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 2016 through December 2016?

A. O&M expenditures are expected to be $1.8 million or 5% lower than originally projected primarily driven by a $1.7 million decrease in CAIR/CAMR CR Project 7.4 – Energy.

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 2016 through December 2016.

A. The $1.7 million decrease is primarily attributable to lower than projected usage of Limestone and Hydrated Lime and reduced ammonia expense driven by a favorable pricing variance. This is partially offset by higher than projected gypsum expense driven by increased cost of sales supporting beneficial use and avoidance of disposal in landfills.

Q: Please explain the variance between actual/estimated O&M project expenditures and original projections for the MATS – CR 1&2 Program (Project 17.2) for the period January 2016 through December 2016.

A: O&M expenditures are expected to be $2 million or 52% lower than originally projected due to better than expected performance through June 2016.

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 2016 through December 2016.

A: Capital expenditures are expected to be $2.5M or 95% lower than originally projected. Based on test burns with western fuel, DEF believes the mechanical and electrical improvements made to the electrostatic precipitators ("ESPs") will be sufficient to improve particulate collection efficiency. Emissions testing has demonstrated sufficient control from the ESPs, such that the flue gas conditioning systems would not be required to comply with applicable opacity and particulate limits. As a result, DEF no longer expects to install the flue gas conditioning systems originally projected.

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

A: Yes. The MATS-CR1&2 Program was completed in April 2016 at a total cost of $31.5 million.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 160007-EI

August 31, 2016

Q. Please state your name and business address.

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

Q. Have you previously filed testimony before this Commission in Docket No. 160007-EI?

A: Yes. I provided direct testimony on April 1, 2016 and August 4, 2016.

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 2017 for Duke Energy Florida LLC's ("DEF" or "Company") Integrated Clean Air Compliance Program (Project 7.4), Mercury and Air

Toxics Standards (MATS) Program – Anclote Gas Conversion (Project 17.1), and Mercury and Air Toxics Standards (MATS) Program – Crystal River Units 1 & 2 (CR1&2) (Project 17.2).

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

A. Yes. I am sponsoring Exhibit No.__ (JS-1), which is an organization chart for DEF's Crystal River Clean Air Projects. I am also co-sponsoring the following portions of Exhibit No. __ (CAM-5) to Christopher A. Menendez's direct testimony:

- 42-5P page 7 of 23 – Clean Air Interstate Rule (CAIR)
- 42-5P page 21 of 23 – MATS Anclote Gas Conversion
- 42-5P page 22 of 23 – MATS Program – CR1&2

Q. What O&M costs does DEF expect to incur in 2017 for air emission controls at Crystal River Units 4 and 5 (CR4&5) as part of the Integrated Clean Air Compliance Program (Project 7.4)?

A. DEF estimates O&M costs of $34.6 million to support the operation and maintenance of air emissions controls that were installed at the CR Energy Complex ("CREC") as outlined in DEF's Integrated Clean Air Compliance Plan as follows:

- Labor costs are estimated at $6.7M based on current staffing levels.
- Contractor expenses are estimated at $4.3M for various services.
- Parts and materials are estimated at $2.2M.

- Other costs are estimated at $168k.
- Project expenses for a surge tank overflow prevention, agitator shaft replacement, AR pump reconditioning and absorber stack inspection are estimated at $543k.
- CR5 outage costs are estimated at $959k.
- Reagent and bi-product costs (ammonia, limestone, hydrated lime, caustic, dibasic acid and net gypsum sales/disposal) are estimated to total $19.6M.

Q. What capital costs does DEF expect to incur in 2017 for the implementation of the Integrated Clean Air Compliance Program (Project 7.4)?

A. CR4&5 coal-fired units generate blowdown wastewater that is discharged to a series of lined ponds for equalization and settling, then further discharged to unlined percolation ponds. In the Conditions of Certification dated August 1, 2012, the Florida Department of Environmental Protection ("FDEP") required DEF to evaluate an alternative disposal method based on results of groundwater monitoring near the percolation ponds. As explained in my August 31, 2015 testimony filed in Docket 150007-EI, DEF has evaluated several treatment options to comply with the FDEP permit requirements and selected a strategy that uses a physical/chemical treatment system with a bioreactor treatment system to treat Flue Gas Desulfurization ("FGD") blowdown wastewater with discharge to surface water or percolation ponds.

DEF estimates 2017 capital costs of $34M for the CR 4&5 FGD Blowdown wastewater project. These costs are for completion of the final design, procurement of processing equipment, completion of civil work scope, completion of piling and foundation work, construction of process tanks, and completion of the installation of the wastewater treatment process control room building.

The total estimated FGD blowdown wastewater project cost is $68.3 million. This is an updated estimate from the original estimate provided in my August 31, 2015 testimony, and the increase in the estimate is a result of further refinement of the project scope, schedule and cost estimates, which include incorporating updated bid information, necessary to meet the Conditions of Certification.

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

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

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

A. The Company established a dedicated unit to manage, operate and maintain the CAIR equipment as shown by the organization chart on Exhibit__(JS-1). This unit consists of 51 employees that report to the Crystal River North Station Manager and 1 employee who reports to the Director-Florida Fossil-Hydro-Finance. There are 7 managers and 44 maintenance, operations and support employees. The operators work rotating shifts in order to staff the operations of CREC 24 hours per day. The maintenance employees primarily work days, but shift employees are available to work when needed. In an effort to keep regular staffing levels low, contractors are used for specialized or lower-skilled work which minimizes overall operation and maintenance costs.

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

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

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

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

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

Equipment-specific training was conducted during the construction and start-up phase of the project and continues as major equipment overhauls are performed. This training included equipment walk-downs, discussions with vendor representatives and hands-on operating and maintenance work performed under the supervision of qualified individuals.

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

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

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

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

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

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

Q. What O&M costs does DEF expect to incur in 2017 for the MATS Program – Anclote Gas Conversion (Project 17.1)?

A. DEF does not expect any costs.

Q. What O&M costs does DEF expect to incur in 2017 for the MATS Program – CR1&2 (Project 17.2)?

A. DEF estimates O&M costs of $1.8 million for CR1&2 MATS compliance. This estimate includes support for reagent injection systems, fuel handling and equipment impacts from burning alternate fuels, and emissions monitoring and testing.

Q. What capital costs does DEF expect to incur in 2017 for the MATS Program – CR1&2 (Project 17.2)?

A. DEF does not anticipate capital costs in 2017.

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

A: Implementation of the CR1&2 MATS Compliance Plan is complete. CR1&2 have operated within compliance of all MATS requirements since the effective date of April 16, 2016.

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. 160007-EI

April 1, 2016

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 Business Services as Director Environmental Field Support – Florida.

Q. What are your responsibilities in that position?

A. 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 Duke Energy Florida's ("DEF") 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 Transmission and Distribution Substation Environmental Investigation, Remediation & Pollution Prevention (SARAP, Projects 1 & 1a), Distribution System Environmental Investigation, Remediation & Pollution Prevention (TRIP, Project 2), Pipeline Integrity Management (PIM) Program (Project 3), Cooling Water Intake – 316(b) (Project 6 & 6a), 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 2015 - December 2015. I also provide an update of the Cross State Air Pollution Rule ("CSAPR") and its impact on DEF's emission allowances, as well an update on the Steam Effluent Limitations Guidelines ("ELG"), Clean Water Rule and Above Ground Storage Tanks ("AST") and Underground Storage Tanks ("UST") amendments. 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. The Company relies on my opinions and information I provide when making decisions regarding these projects.

Q. How did actual O&M expenditures for January 2015 - December 2015 compare with DEF's actual/estimated projections for the Transmission & Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention Projects (Projects 1 & 1a)?

A. The Substation System Program variance is $507,405 or 46% lower than projected. This variance is primarily due to delays at Consolidated Rock distribution substation, and East Clearwater, Holder, Pasadena, and Winter Springs transmission substations. Consolidated Rock remediation is delayed due to restricted access by the property owner. Work will begin once this issue is resolved. East Clearwater repairs are scheduled for 2016. Holder remediation is deferred until the Fall of 2016 when breaker replacement work is completed.

Pasadena repairs were completed February 25, 2016. Winter Springs repairs are scheduled to start March 28, 2016.

Q. How did actual O&M expenditures for January 2015 - December 2015 compare with DEF's actual/estimated projections for the Distribution System Environmental Investigation, Remediation, and Pollution Prevention Project (Project 2)?

A. The Distribution System Environmental Investigation, Remediation, and Pollution Prevention Project variance is $37,666 or 65% lower than projected due to delays in source removal at two transformer sites in December 2015 and January 2016. These delays were due to site access issues at one location and structural engineering excavation drawing requirements by the local municipality at another.

Q. How did actual O&M expenditures for January 2015 - December 2015 compare with DEF's actual/estimated projections for the PIM Project (Project 3)?

A. The PIM O&M variance is $181,689 or 35% lower than projected. This variance is attributed to the cost of the Duke Energy Trail and FDOT Gandy projects being lower than anticipated and DEF being reimbursed in full for the FDOT Gandy project.

Q. How did actual O&M expenditures for January 2015 - December 2015 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 $30,659 or 11% lower than projected. Cooling Water Intake 316(b) (Project 6) – Base had a $16,912 or 12% lower than projected variance due to scheduled work delayed for the evaluation of a proposed site cooling water system at the Crystal River North station. Cooling Water Intake 316(b) – Intermediate (Project 6a) had a $13,747 or 11% lower than projected variance due to report preparation in support of Suwannee Station NPDES permit renewal being deferred until 2016.

Q. How did actual O&M expenditures for January 2015 - December 2015 compare with DEF's actual/estimated projections for the Arsenic Groundwater Standard Project (Project 8)?

A. The Arsenic Groundwater Monitoring variance is $9,476 or 24% higher than projected due to additional consultant costs to address an arsenic consent order issued by the FDEP.

Q. How did actual capital expenditures for January 2015 - December 2015 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 $284,479 or 10% lower than projected, due to commissioning activities being rescheduled from fourth quarter 2015 to first quarter 2016.

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 the Cross State Air Pollution Rule ("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 NO_x 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 NO_x 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 NO_x 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. On

July 28, 2015, the D.C. Circuit determined that EPA failed to cost justify a number of Phase 2 emission allowance budgets for certain states, including Florida, citing they were more stringent than necessary to achieve air compliance in downwind states, and held the Phase 2 NO_x allowance allocations invalid. Finally, on November 17, 2015, the EPA proposed a revised CSAPR. The EPA proposed to remove Florida from the CSAPR program, beginning with the 2017 ozone season; however, the EPA stated that it will perform additional modeling that could result in changing that proposal. A final revised CSAPR is expected in mid- to late-2016.

Q. What is the status of the ELG (Project 15)?

A. On November 23, 2015, the Environmental Protection Agency (EPA) published the final revision to the ELG establishing technology-based national standards for effluent waste streams. The rule went into effect on January 4, 2016 and applies to all steam electric generating stations. The new limits must be incorporated into affected stations' NPDES permits with a compliance timeframe between November 1, 2018 and December 31, 2023. DEF is currently working with the FDEP to address these ELG requirements in its Crystal River Units 4 and 5 NPDES permit that is now in the renewal process.

Q. **What is the status of the Clean Water Rule?**

A. On June 29, 2015 the EPA and the Army Corps of Engineers (Corps) published the final Clean Water Rule that significantly expands the definition of the Waters of the United States ("WOTUS"). On October 9, 2015 the U.S. Court of

Appeals for the Sixth Circuit granted a nationwide stay of the rule effective through the conclusion of the judicial review process. On February 22, 2016 the court issued an opinion that it has jurisdiction and is the appropriate venue to hear the merits of legal challenges to the rule; however, that decision is being contested, and the timeframe for resolution is unknown at this time. Until the new rule goes into effect, new WOTUS jurisdictional determinations will be made by the Corps using the previous WOTUS definition.

Q. What is the status of the FDEP's Underground Storage Tank (UST) Rule (Project 10)?

A. The FDEP's proceedings on rulemaking continue. The final public workshop was held on March 28, 2016. DEF continues to analyze the draft rule requirements and potential impacts at operational sites and compliance options for the affected unit. However, the full extent of compliance activities and associated expenditures cannot be determined at this time as the final rule has not been issued and is still subject to change.

Q. What is the status of FDEP's Aboveground Storage Tank (AST) Rule (Project 4)?

A. The FDEP's proceedings on rulemaking continue. The final public workshop was held on March 28, 2016. DEF continues to analyze the draft rule requirements and potential impacts at operational sites and compliance options for the affected units. However, the full extent of compliance activities and associated expenditures cannot be determined at this time as the final rule has not been issued and is still subject to change.

Q. Does this conclude your testimony?

A. Yes.

ERRATA SHEET

Docket No. 160007-EI
Witness: Patricia Q. West
Date: August 10, 2016

Page 4

Lines 16-17:

"…520.420(1), F.A.C.) to lower the arsenic maximum containment level from 50 ppb to 10 ppb."

Should read:

"…520.420(1), F.A.C.) to lower the arsenic maximum contaminant level from 50 ppb to 10 ppb."

STATE OF FLORIDA
COUNTY OF PINELLAS

8/10/16
Date

Patricia Q. West
Patricia Q. West

I, the undersigned authority, certify that Patricia Q. West personally appeared before me and was duly sworn.

Witness my hand and seal this 10th day of August, 2016.

Jennifer Garwood
Notary Public, State of Florida

NOTARY PUBLIC STATE OF FLORIDA
JENNIFER GARWOOD
MY COMMISSION # FF972067
EXPIRES: March 22, 2020

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>PATRICIA Q. WEST</u>

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 160007-EI

August 4, 2016

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. 160007-EI?

A: Yes, I provided direct testimony on April 1, 2016.

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 2016 actual/estimated cost projections and original 2016 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 Program (Project 15.1), 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 2016 through December 2016.

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 2016 through December 2016.

A: O&M expenditures for the substation system program are estimated to be $312k or 29% lower than originally projected. The variance is in part due to remediation delays at Consolidated Rock, Dunedin, East Clearwater, Holder, Kenneth City, Longwood, and Winter Springs substations. Consolidated Rock remediation is delayed due to restricted access by the property owner. Dunedin's three banks will now be replaced in Fall 2017 in lieu of repairing as initially scheduled. East Clearwater remediation is partially complete; the remaining remediation is being scheduled. Holder remediation is scheduled for November 2016. Kenneth substation is currently under construction, and remediation activities are tentatively scheduled for October 2016. Winter Springs remediation was delayed due to the need to complete emergent work at Winter Park East, and has been rescheduled for September 2016. Remediation activities at Wekiva substation commenced the first week of July 2016.

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 2016 through December 2016.

A: O&M expenditures for the distribution system program are estimated to be $101k higher than originally projected due to the timing of 2015 invoices that were received and paid in 2016 and a delay in a TRIP location originally planned to start and finish in 2015 but was not completed until early 2016.

Q: Please explain the variance between actual/estimated project expenditures and original projections for CAIR/CAMR - Peaking (Project 7.2) for the period January 2016 through December 2016.

A: O&M expenditures for CAIR/CAMR - Peaking are projected to be $32k or 24% lower than originally projected due to the retirement of the Turner Peaking Units thereby removing the need for Appendix E testing.

Q: Please explain the variance between actual/estimated project expenditures and original projections for Arsenic Groundwater Standard (Project 8) for the period January 2016 through December 2016.

A: O&M expenditures for Arsenic Groundwater Standard are expected to be $131k higher than originally projected due to consultant costs to evaluate the source of arsenic exceedances and issue a summary report in accordance to FDEP Consent Order No. 09-3463D executed on March 22, 2016. The summary report must be submitted to the FDEP no later than December 31, 2017, and the station must be in compliance with the arsenic groundwater limit by December 31, 2019. The Consent Order was issued by the FDEP for exceedance of the revised arsenic groundwater limit. In 2005, the FDEP revised the Ground Water Rule (65-520.420(1), F.A.C.) to lower 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 MATS – CR4&5 (Project 17) capital for the period January 2016 through December 2016.

A: Capital expenditures for MATS – CR4&5 are expected to be $310k higher than originally projected due to commissioning activities being rescheduled from fourth quarter 2015 to first quarter 2016.

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

A: In April 2013, the Environmental Protection Agency ("EPA") proposed revised effluent limitation guidelines and standards for the Steam Electric Generating Industry pursuant to the Clean Water Act. 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. On November 23, 2015, the EPA published the final revision to the ELG establishing technology-based national standards for effluent waste streams. The rule went into effect on January 4, 2016 and applies to all steam electric generating stations. The new limits must be incorporated into affected stations' NPDES permits with a compliance timeframe between November 1, 2018 and December 31, 2023. DEF is currently working with the FDEP to address these ELG requirements in its Crystal River Units 4 & 5 NPDES permit that is now in the renewal process.

Q: Please provide an update of DEF's Effluent Limitation Guidelines Program (Project 15.1).

A: In Order No. PSC-13-0606-FOF-EI, the Commission approved DEF's ELG compliance project as meeting the criteria for ECRC recovery. DEF's progress on this project was deferred as a result of EPA's decision to defer final guidelines. With the publication of the final Effluent Limitation Guidelines, DEF will begin initial engineering analysis in late-2016. DEF expects to incur costs of approximately $225k in 2016.

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 twenty-five percent (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 implementing initial rule requirements based on NPDES permit schedules at affected facilities which includes literature review and analysis, additional field study, and reporting requirements.

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. On October 23, 2015, EPA published the final New Source Performance Standards (NSPS) for CO_2 emissions from existing fossil fuel-fired electric generating units (also known as the Clean Power Plan or CPP). The final CPP establishes state-specific emission goals; for Florida, the goals begin a phased approach in 2022, ending with a rate goal of 919 lb. CO_2/MWh annual average for the period 2030 and beyond. Alternatively, the state can adopt a mass emissions approach culminating in a 2030 target of 105,094,704 tons (existing units) or 106,641,595 tons (existing plus new units). The final CPP has been challenged in the D.C. Circuit Court of Appeals by 27 states and a number of industry groups, oral argument is scheduled for September 27, 2016. In addition, on February 9, 2016, the U.S. Supreme Court placed a stay on the CPP until such time that all litigation is completed.

Also, on October 23, 2015, EPA published the final New Source Performance Standards (NSPS) for CO_2 emissions for new, modified, and reconstructed fossil fuel-fired EGUs. The rule includes emission limits of 1,400 lb. CO_2/MWh for new coal-fired units and 1,000 lb. CO_2/MWh for new natural gas combined-cycle units. This rule has also been challenged in the D.C. Circuit Court of Appeals.

DEF does not expect to incur ECRC costs in 2016 related to carbon regulations.

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

A: There have been no updates on the CSAPR since my April 1, 2016 testimony.

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

A: The CCR rule was published in the Federal Register on April 17, 2015, and became 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. DEF's planned 2016 compliance activities and their associated cost projections are provided by Mr. Timothy Hill.

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. In turn, on December 15, 2015 the D.C. Circuit Court of Appeals remanded the MATS rule to EPA without vacatur. On April 15, 2016 EPA issued the final "Supplemental Findings that it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units." Petitions have been filed with the Court challenging EPA's findings. In the interim, the MATS rule will remain in effect pending any additional action by the D.C. Circuit.

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

A: The EPA set new 1-hour health-based NO2 and SO2 standards in 2010. In mid-2013, the EPA finalized SO2 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 August 21, 2015, the EPA published a final "data requirements" rule that establishes requirements for additional ambient air quality monitoring and/or modeling that will be used for future area designations.

On October 26, 2015, the EPA published a revised ozone NAAQS, making the standard more stringent by changing it from 75 parts per billion (ppb) to 70 ppb. Currently the entire state of Florida is in compliance with this new standard.

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

A: On June 29, 2015 the EPA and the Army Corps of Engineers ("Corps") published the final Clean Water Rule that significantly expands the definition of the Waters of the United States ("WOTUS"). On October 9, 2015 the U.S. Court of Appeals for the Sixth Circuit granted a nationwide stay of the rule effective through the conclusion of the judicial review process. On February 22, 2016 the court issued an opinion that it has jurisdiction and is the appropriate venue to hear the merits of legal challenges to the rule; however, that decision is being contested, and the timeframe for resolution is unknown at this time. Until the new rule goes into effect, new WOTUS jurisdictional determinations will be made by the Corps using the previous WOTUS definition.

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. 160007-EI

August 31, 2016

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. 160007-EI?

A: Yes. I provided direct testimony on April 1, 2016 and August 4, 2016.

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 2017 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 15.1), 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. __(CAM-5) to Christopher A. Menendez's direct testimony:

- 42-5P page 1 of 23 – Substation Environmental Investigation, Remediation and Pollution Prevention Program

- 42-5P page 2 of 23 - Distribution System Environmental Investigation, Remediation and Pollution Prevention Program
- 42-5P page 3 of 23 – PIM
- 42-5P page 4 of 23 - AST
- 42-5P page 6 of 23 - Phase II Cooling Water Intake
- 42-5P page 7 of 23 – Clean Air Interstate Rule ("CAIR")
- 42-5P page 8 of 23 – BART
- 42-5P page 9 of 23 - Arsenic Groundwater Standard
- 42-5P page 10 of 23 – Sea Turtle – Coastal Street Lighting Program
- 42-5P page 11 of 23 - UST
- 42-5P page 12 of 23 - Modular Cooling Towers
- 42-5P page 13 of 23 - Thermal Discharge Permanent Cooling Tower
- 42-5P page 14 of 23 - Greenhouse Gas Inventory and Reporting
- 42-5P page 15 of 23 - Mercury TMDL
- 42-5P page 16 of 23 - HAPs ICR
- 42-5P page 17 of 23 - Effluent Limitation Guidelines ICR Program
- 42-5P page 18 of 23 - Effluent Limitation Guidelines CRN Program
- 42-5P page 19 of 23 - NPDES
- 42-5P page 20 of 23 - MATS – CR4&5

Q. What costs does DEF expect to incur in 2017 for the Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a)?

A. DEF estimates $999k of O&M costs at 11 sites for the Substation Environmental Investigation, Remediation and Pollution Prevention Program. These costs also include institutional controls and report writing activities for various substations in the program.

Q. What costs does DEF expect to incur in 2017 for the Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2)?

A. DEF is not projecting any charges for the Distribution System Investigation, Remediation, and Pollution Prevention Program (Project 2).

Q. What costs does DEF expect to incur in 2017 for the PIM Program (Project 3)?

A. DEF estimates $246k 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 2017 for the Aboveground Storage Tank ("AST") Program (Project 4)?

A. DEF does not expect any costs in 2017. The Florida Department of Environmental Protection ("FDEP") has noticed its proposed AST rule revisions in the Florida Administrative Register and such rules, once adopted by the agency, will undergo review by the Joint Administrative Procedures Committee as required by Chapter 120, Florida Statutes. The AST rule revisions are expected to be legally effective by the end of calendar year 2016.

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 2017 for the Phase II Cooling Water Intake Program (Project 6)?

A. DEF estimates $208k 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 2017 for the CAIR/CAMR Program (Project 7.2)?

A. DEF estimates $92k 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. This testing must be performed on all of its Predictive Emissions Monitoring Systems. Four stations will be tested in 2017.

Q: What costs does DEF expect to incur in 2017 for the BART Program (Project 7.5)?

A: DEF does not expect any costs.

Q. What costs does DEF expect to incur in 2017 for the Arsenic Groundwater Standard Program (Project 8)?

A. DEF estimates $120k in O&M costs for the Arsenic Groundwater Standard Program. In accordance to FDEP Consent Order No. 09-3463D executed on March 22, 2016 DEF continues its investigation to evaluate the potential source of arsenic groundwater exceedances. A summary report of findings will be submitted to the FDEP no later than December 31, 2017, and the Station must be in compliance with the arsenic groundwater limit by December 31, 2019 in accordance with the Consent Order. The original Consent Order was issued by the FDEP for exceedance of the arsenic groundwater limit following the 2005 revision of the state's groundwater standard that lowered the arsenic maximum contaminant level from 50 ppb to 10 ppb.

Q. What costs does DEF expect to incur in 2017 for the Sea Turtle – Coastal Street Lighting Program (Project 9)?

A. DEF estimates $450 and $500 in O&M and capital costs, respectively, for the Sea Turtle – Coastal Street Lighting Program. The O&M costs are to install mitigation on any existing street lights during nesting season that may interfere with sea turtle nesting for Gulf County, Mexico Beach, and Pinellas County. Capital costs are projected to install new street lights if required in Gulf County, Mexico Beach, and Pinellas County and any lighting required for the Don Cesar project in Pinellas County.

Q. What costs does DEF expect to incur in 2017 for the Underground Storage Tanks ("UST") Program (Project 10)?

A. DEF does not expect any costs in 2017. FDEP has noticed its proposed UST rule revisions in the Florida Administrative Register and such rules, once adopted by the agency, will undergo review by the Joint Administrative Procedures Committee as required by Chapter 120, Florida Statutes. The UST rule revisions are expected to be legally effective by the end of calendar year 2016.

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 2017 for the Modular Cooling Tower (Project 11)?

A. DEF does not expect any costs.

Q. What costs does DEF expect to incur in 2017 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 2017 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 2017 for the Mercury TMDL Program (Project 13)?

A. DEF does not expect any costs.

Q. What costs does DEF expect to incur in 2017 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 2017 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 2017 for the Effluent Limitation Guidelines CRN Program (Project No. 15.1)?

A. DEF is projecting $4.1M in capital costs for the ELG Crystal River North project. On September 30, 2015, U.S. Environmental Protection Agency finalized the Steam Electric Power Generating Effluent Guidelines, 40 CFR Part 423, imposing federal standards on several power plant streams that are discharged to surface water. In the final regulation, closed-loop systems or dry handling have been identified as the Best Available Technology ("BAT") for bottom ash transport water. Crystal River North Units 4 & 5 have a dry bottom ash system that utilizes dewatering bins for separation of bottom ash and water. However, the current configuration has the potential for bottom ash transport water to leave via overflows and drain into an NPDES internal outfall. The closed loop bottom ash compliance requirement must be achieved as soon as possible, beginning November 1, 2018 but no later than December 31, 2023. Renewal of the Crystal River Units 4 & 5 NPDES permit is in progress and addresses this requirement. Duke Energy is seeking a compliance date of February 1, 2020 to include modification of the existing system.

Q. What costs does DEF expect to incur in 2017 for the NPDES Program (Project No. 16)?

A. DEF estimates $81k 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 2017 for the MATS Program – CR4&5 (Project No. 17)?

A. DEF estimates O&M costs of approximately $598k for CR4&5 MATS compliance. This estimate includes emissions testing, burner inspections, maintenance of emissions monitoring and control technologies, and reagent costs.

Q. What capital costs does DEF expect to incur in 2017 for the MATS Program – CR4&5 (Project No. 17)?

A. DEF does not expect capital expenditures in 2017.

Q. Please provide an update on Carbon Regulations.

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. On October 23, 2015, EPA published the final New Source Performance Standards ("NSPS") for CO_2 emissions from existing fossil fuel-fired electric generating units (also known as the "Clean Power Plan" or "CPP"). The final CPP establishes state-specific emission goals; for Florida, the goals begin a phased approach in 2022, ending with a rate goal of 919 lb. CO_2/MWh annual average for the period 2030 and beyond. Alternatively, the state can adopt a mass emissions approach culminating in a 2030 target of 105,094,704 tons (existing units) or 106,641,595 tons (existing plus new units). The final CPP has been challenged in the D.C. Circuit by 27 states and a number of industry groups. Oral argument in the D.C. Circuit Court of Appeals is scheduled for September 27, 2016. In addition, on February 9, 2016, the U.S. Supreme Court placed a stay on the CPP until such time that all litigation is completed.

New Units - Also, on October 23, 2015, EPA published the final NSPS for CO_2 emissions for new, modified, and reconstructed fossil fuel-fired EGUs. The rule includes emission limits of 1,400 lb. CO_2/MWh for new coal-fired units and 1,000 lb. CO_2/MWh for new natural gas combined-cycle units. This rule has also been challenged in the D.C. Circuit.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

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

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

A. I hold a Bachelor of Arts degree in Economics from the University of New Orleans and a Master of Arts degree in Economics from the University of South Florida. 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 during my 19 years of electric utility experience, including load forecasting, managing cost recovery clauses, 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 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 2015 through December 2015 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 2015 through December 2015 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 2015 through December 2015?

A. The final true-up amount for the Environmental Clause for the period January 2015 through December 2015 is an over-recovery of $1,721,184. The actual environmental cost over-recovery, including interest, is $6,256,457 for the period January 2015 through December 2015, as identified in Form 42-1A. This amount, less the $4,535,273 over-recovery approved in Commission Order No. PSC-15-0536-FOF-EI, issued November 19, 2015, in Docket No. 150007-EI, results in a final over-recovery of $1,721,184, as shown on Form 42-1A. This over-recovery amount will be applied in the calculation of the environmental cost recovery factors for the period January 2017 through December 2017.

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 2015 final Environmental Clause true-up filing for any environmental projects that were not anticipated and included in its 2015 factors?

A. Yes, Tampa Electric included costs associated with Tampa Electric's Coal Combustion Residual ("CCR") project. These costs are outlined on forms 42-4A and 42-5A. This project was approved for cost recovery by Commission Order No. PSC-16-0068-PAA-EI, issued February 9, 2016.

Q. How do actual expenditures for the January 2015 through December 2015 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 $808,925, or 3.2 percent less than the actual/estimated projection costs. Form 42-6A shows the total capital investment costs are $7,981, or 0.01

percent less than the actual/estimated projection costs. Additional information regarding material variances is provided below.

O&M Project Variances

O&M expense projections related to planned maintenance work are typically spread across the period in question. However, the company always inspects the units to ensure that the maintenance is needed, before beginning the work. The need varies according to the actual usage and associated "wear and tear" on the units. If an inspection indicates that the maintenance is not yet needed, then the company will have a variance compared to the projection; and the maintenance expense will be incurred in a future period when warranted by the condition of the unit.

- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is $15,104 or 99.4 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 projected.
- **Big Bend NO_x Emission Reduction:** The Big Bend NO_x Emission Reduction project variance is $51,150, or 46.7 percent less than projected. The actual/estimated projection expenses include periodic testing or maintenance for this

equipment. Upon inspection, the company determined that it was not necessary to perform the maintenance during 2015.

- **Polk NO_x Emission Reduction:** The Polk NO_x Emission Reduction project variance is $2,015, or 19.5 percent less than projected. This variance is due to an outage for Polk Unit 1. Due to the extended outage, there was minimal maintenance needed for this project, resulting in a decrease when compared to the projected costs.
- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance is $53,899, or 35.8 percent greater than projected. This variance is due to an increase in the amount of time the unit ran, compared to the projection, resulting in a greater amount of consumables used.
- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance is $24,000, or 100 percent less than projected. The costs associated with this project are less than originally projected due to this unit not requiring the projected maintenance.
- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is $104,814, or 81.5 percent less than projected. This variance is due to maintenance work that was anticipated to occur but was not necessary during 2015.
- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR

project variance is $17,038, or 32.5 percent less than projected. The costs associated with this project are less than projected since the projected maintenance work was not required during 2015.

- **Bid Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is $6,457, or 26.9 percent less than projected. The costs associated with this project are less than projected because this unit did not require the projected maintenance work during 2015.
- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) project variance is $309,627, or 83.5 percent less than projected. This variance is due to delays caused by the uncertainty surrounding the cascading effect of the Clean Power Plan through other regulations.
- **Arsenic Groundwater Study Program:** The Arsenic Groundwater project variance is $39,347, or 68.4 percent less than projected. This variance is due to ongoing negotiations with the FDEP regarding groundwater treatment at Bayside Station.
- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is $404,013, or 17.2 percent less than projected. This variance is due to an outage that decreased the amount of ammonia consumed, compared to projections.

- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is $620,109, or 33 percent less than projected. This variance is due to an outage that decreased the amount of ammonia consumed, compared to projections. Additionally, less maintenance than projected was needed.
- **Mercury Air Toxics Standards:** The Mercury Air Toxics Standards (“MATS”) project variance is $99,263, or 54.1 percent less than originally projected. 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 $1,085,564, or 101.3 percent greater than projected. This variance is due to an error in the projection of costs associated with this project that caused the projected costs to be understated.

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 hold a Bachelor of Arts degree in Economics from the University of New Orleans and a Master of Arts degree in Economics from the University of South Florida. 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 during my 19 years of electric utility experience, including load forecasting, managing cost recovery clauses, project management, and rate

setting activities for wholesale and retail rate cases. My current duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and 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 2016 through December 2016 actual/estimated true-up amount to be refunded or recovered through the Environmental Cost Recovery Clause ("ECRC") during the period January 2017 through December 2017. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2016, 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 2017 through December 2017.

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

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 2017 through December 2017.

Q. What has Tampa Electric calculated as the actual/estimated true-up for the current period to be applied to the January 2017 through December 2017 ECRC factors?

A. The actual/estimated true-up applicable for the current period, January 2016 through December 2016, is an over-recovery of $5,755,973. 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 2016 ECRC factors?

A. Yes, Tampa Electric is including costs for projects that were approved after the 2016 ECRC factors were set. The new projects are the Coal Combustion Residuals project, approved by the Commission in Order No. PSC-16-0094-PAA-EI issued on February 9, 2016, in Docket No. 150223-EI, and the Effluent Limitation Guidelines project, approved by the Commission in Order No. PSC-16-0248-PAA-EI issued on June 28, 2016, in Docket No. 160027-EI. These two projects were not included in the company’s 2016 ECRC factors.

Q. What depreciation rates were utilized for the capital projects contained in the 2016 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 2016 through December 2016?

A. Tampa Electric’s revenue requirement rate of return for January 2016 through December 2016 is calculated based on the capital structure, components and cost rates approved in Order No. PSC-12-0425-PAA-EU, issued on August 16, 2012 in Docket No. 120007-EI. The calculation of the revenue requirement rate of return is shown on Form 42-9E.

Q. How did the actual/estimated project expenditures for the January 2016 through December 2016 period compare with the company's original projections?

A. As shown on Form 42-4E, total O&M costs are expected to be $4,588,481 less than the amount that was originally projected. The total capital expenditures itemized on Form 42-6E, are expected to be $253,819 less than originally projected. Significant variances for O&M and capital investment projects are explained below.

O&M Project Variances

- **Big Bend Units 1 & 2 FGD**: The Big Bend Units 1 & 2 FGD project variance is estimated to be $1,570,976 or 16 percent less than projected. The recent historically low prices of natural gas caused the company to dispatch natural gas-fired units as baseload units, displacing coal-fired generation for base load. This variance is due to Big Bend Units 1 and 2 burning more natural gas and less coal than projected earlier this year, which resulted in a reduction in the amount of consumables and maintenance needed.

- **Big Bend NOx Emissions Reduction:** The Big Bend NOx Emissions Reduction project variance is estimated to be $64,079 or 49.3 percent less than projected. This variance is due to the increased use of natural gas and reduced use of coal, resulting in less maintenance required.

- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance is estimated to be $42,000 or 100 percent less than projected. Since the company has burned less coal during 2016 than projected, there is not any expected maintenance associated with this project for 2016.

- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is estimated to be $26,757 or 63.7 percent less than projected. The company burned less coal at Big Bend Unit 1 than projected, eliminating the need for much of the maintenance on this unit.

- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR project variance is estimated to be $15,467 or 36.8 percent greater than projected. There was a need to replace an additional bearing on the unit that increased the actual costs of this project.

- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is estimated to be $40,460 or 96.3 percent less than projected. The company burned less coal at Big Bend Unit 3 than projected, eliminating the need for much of the maintenance on this unit.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program variance is estimated to be $10,278 or 41.1 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 $580,846 or 60.5 percent less than originally projected. This variance is due to uncertainty associated with the compliance strategy as a result of the stay of the Clean Power Plan.

- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is estimated to be $682,640 or 33.7 percent less than originally projected. This variance was caused by the company burning more natural gas and less coal than projected. The reduction in the amount of coal burned reduces costs since less consumables and maintenance are needed.

- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is estimated to be $481,572 or 29.9 percent less than originally projected. This variance is due to burning more natural gas and less coal than projected. The reduction in the amount of coal burned reduces the amount of consumables and maintenance needed.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is estimated to be $929,338 or 45.7 percent less than originally projected. The variance is due to burning more natural gas and less coal than projected. The reduction in the amount of coal burned reduces the amount of consumables and maintenance needed.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is estimated to be $859,573 or 41.5 percent less than originally projected. The variance is due to burning more natural gas and less coal than projected. The reduction in the amount of coal burned reduces the amount of consumables and maintenance needed.

- **Mercury Air Toxics Standards (“MATS”):** The MATS program variance is expected to be $100,534 or 43.7 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.

Capital Investment Project Variances

- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance is estimated to be $167,674 or 7.3 percent less than projected. This variance is due to the plant in-service amount being less than expected, resulting in a lower cost for the project depreciation and return.

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 hold a Bachelor of Arts degree in Economics from the University of New Orleans and a Master of Arts degree in Economics from the University of South Florida. 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 during my 19 years of electric utility experience, including load forecasting, managing cost recovery clauses, 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 approved environmental projects.

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

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the revenue requirements and the projected ECRC factors for the period of January 2017 through December 2017. 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 2017.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2017 through December 2017?

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 2017.

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 2017 through December 2017.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2017 through December 2017?

A. The net true-up applicable for this period is an over-recovery of $7,477,157. This consists of the final true-up over-recovery of $1,721,184 for the period of January 2015 through December 2015 and an estimated true-up over-recovery of $5,755,973 for the current period of January 2016 through December 2016. 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 August 4, 2016.

Q. Did Tampa Electric include any new environmental compliance projects for ECRC cost recovery for the period from January 2017 through December 2017?

A. No, Tampa Electric is not including any new environmental compliance projects for ECRC cost recovery during 2017.

Q. What are the existing capital projects included in the calculation of the ECRC factors for 2017?

A. Tampa Electric proposes to include for ECRC recovery the 26 previously approved capital projects and their projected costs in the calculation of the 2017 ECRC factors. 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 No. 1 Upgrade
5) Big Bend Fuel Oil Tank No. 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
26) Coal Combustion Residuals ("CCR") Rule

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

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2017?

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 26, provides the calculations of the costs, which result in recoverable jurisdictional capital costs of $52,435,114.

Q. What are the existing O&M projects included in the calculation of the ECRC factors for 2017?

A. Tampa Electric proposes to include for ECRC recovery the 25 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2017. 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
24) Coal Combustion Residuals ("CCR") Rule
25) Effluent Limitations Guidelines ("ELG")

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

Q. Have you prepared a schedule showing the calculation of the recoverable O&M project costs for 2017?

A. Yes. Form 42-2P contained in Exhibit No. PAR-3 summarizes the recoverable jurisdictional O&M costs for these projects which total $28,800,804 for 2017.

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 33.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2017?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $81,235,918.

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 2017 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 2017 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 2017 proposed ECRC billing factors are as follows:

Rate Class	**Factor by Voltage Level(¢/kWh)**
RS Secondary	0.389
GS, TS Secondary	0.388
GSD, SBF	
Secondary	0.386
Primary	0.382
Transmission	0.378

IS	
Secondary	0.379
Primary	0.375
Transmission	0.371
LS1	0.381
Average Factor	0.387

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 2017.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2017 through December 2017?

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 2017 through

December 2017 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 0.387 cents per kWh. This includes the projected capital and O&M revenue requirements of $81,235,918 associated with a total of 33 environmental projects and a net true-up over-recovery provision of $7,477,157. My testimony also explains that the projected environmental expenditures for 2017 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

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 2017 through December 2017 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 (0570039-083-AV). The projects that are now required under the operating permit are listed below.

- Big Bend PM Minimization Program
- Big Bend NOx Emission Reduction Program
- Big Bend Units 1 – 3 Pre-Selective Catalytic Reduction ("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. The requirements of the Orders 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 2017 through December 2017.

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 2017; 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 $611,283.

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 2017 through December 2017.

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 2017; however, the company will perform maintenance on the previously approved and installed NO_x reduction equipment. This activity is expected to result in approximately $100,000 of O&M expenses during 2017.

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 2017 through December 2017.

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 2017 through December 2017, 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 $37,200 for Big Bend Unit 1 Pre-SCR, $37,200 for Big Bend Unit 2 Pre-SCR and $37,200 for Big Bend Unit 3 Pre-SCR for equipment maintenance. There are not any anticipated capital expenditures for Big Bend Units 1, 2, and 4 SCRs. The capital expenditures for the Big Bend Unit 3 SCR are projected to be $800,382 for a catalyst replacement. Additionally, the 2017 SCR O&M expenses are projected to be $1,771,104 for Big Bend Unit 1 SCR, $2,076,788 for Big Bend Unit 2 SCR, $1,865,423 for Big Bend Unit 3 SCR and

$1,086,684 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 Flue Gas Desulfurization ("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
11) Coal Combustion Residuals ("CCR")
12) Effluent Limitation Guidelines ("ELG")

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 2017 through December 2017.

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 2017 through December 2017 for the Big Bend Unit 3 FGD Integration project; however, O&M expenses are projected to be $5,539,740 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 2017 through December 2017. O&M expenses are projected to be $9,108,893 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 2017 through December 2017.

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 2017 through December 2017, 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 2017 through December 2017.

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 2017 through December 2017, 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 2017 through December 2017.

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 $948,000 for the period January 2017 through December 2017 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 2017 through December 2017.

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 2017 through December 2017, 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 2017 through December 2017.

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 2017 through December 2017, 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. 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. Compliance with the rule began on April 16, 2015. Tampa Electric is currently meeting or exceeding the standards required by the MATS rule for mercury, particulate matter, and acid gases at Polk Power Station and Big Bend Power Station.

Q. Please provide the MATS program estimated capital and O&M expenditures for the period January 2017 through December 2017.

A. For 2017, Tampa Electric anticipates capital expenditures of $160,000 under the MATS program for monitoring equipment. O&M expenditures are projected to be $231,000 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 2017 through December 2017.

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 2017. For 2017, this activity is projected to result in approximately $90,000 of O&M expenditures.

Q. Please describe the Big Bend Gypsum Storage Facility activities and provide the estimated capital and O&M expenditures for the period of January 2017 through December 2017.

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 the ECRC. The project was placed in-service in November 2014. For 2017, Tampa Electric does not anticipate any capital expenditures; however, projected O&M expenses for this program during 2017 are $1,200,000.

Q. Please describe the EPA Coal Combustion Residuals ("CCR") Rule compliance activities and provide the estimated capital and O&M expenditures for the period of January 2017 through December 2017.

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 became 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 CCR program was approved by the Commission in Order No. PSC-16-0094-PAA-EI issued on February 9, 2016, in Docket No. 150223-EI. In that Order, the Commission found that the program meets the requirements for recovery through the ECRC. Incremental O&M expenses resulting from the groundwater monitoring program, ongoing inspections and general maintenance of regulated units will continue throughout 2017 and beyond. In order to determine the best option to comply with the new rule, the company evaluated whether to continue operation of the regulated impoundments or to close them.

The impoundments for which closure will commence in 2017 are the North and South Economizer Ash Impoundments and the Slag Pond, for which engineering and scope studies are in progress. These closure projects are now scheduled to begin concurrently in 2017 to avoid compliance-related O&M costs and to yield efficiencies in the engineering and construction of these projects. The cost estimates provided for the closures are based on the clean closure option allowed by the rule and therefore include O&M costs for disposal of CCRs excavated from these impoundments.

In addition, ongoing compliance evaluations of FGD operations at Big Bend Station have revealed that additional work must be done at the North Gypsum Stackout area, another area where CCRs are managed on site at the station. The supplemental work includes drainage improvements and secondary containment in the main storage area, as well as additional remediation and improvements to line the adjacent unlined ditches and ponds. This work is needed to make the FGD operations fully compliant with the CCR Rule requirements.

Tampa Electric anticipates $6,350,000 for capital expenditures and $3,700,000 for O&M expenditures for the projects described above. However, engineering of these projects will include more detailed cost evaluations, and these projections will be refined upon completion of the evaluations.

Q. Please describe Tampa Electric's Effluent Limitation Guidelines activities and provide the estimated O&M expenditures for the period January 2017 through December 2017.

A. On November 3, 2015 the EPA published the final Steam Electric Power Generating Effluent Limitations Guidelines, with an effective date of January 4, 2016. The ELG establish limits for wastewater discharges from FGD processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing CCR, gasification processes, and flue gas mercury controls. Big Bend Station's FGD system is affected by this rule. The blow-down stream from the FGD System is currently sent to a physical chemical treatment system to remove solids, some metals, ammonia and adjust pH prior to discharge to Tampa Bay via the once-through condenser cooling system water. This treatment system will need to be modified or replaced in order to achieve compliance with the new EPA regulations. The rule requires compliance after November 1, 2018, but no later than December 31, 2023.

The ELG project was approved by the Commission in Order No. PSC-16-0248-PAA-EI issued on June 28, 2016, in Docket No. 160027-EI. In that Order, the Commission found that the program meets the requirements for recovery through the ECRC. Tampa Electric projects O&M expenditures for the period January 2017 through December 2017 to be $50,000 for front-end engineering and design of the technology selected in the feasibility study.

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 CFJ and CD are have been incorporated into Big Bend's Title V Operating Permit (0570039-083-AV) and are 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 2017. Additionally, my testimony identified other projects that are required for Tampa Electric to meet environmental requirements, and I provided the associated 2017 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. 160007-EI
April 1, 2016

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 2015.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2015 through December 2015 with the approved estimated true-up amounts.

A. As reflected in Mr. Boyett's Schedule 6A, the actual recoverable capital costs were $121,846,050 as compared to $123,962,048 included in the Estimated True-up filing. This resulted in a net variance of $2,115,998 under 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 ($2,048,144) or (2.2%) in the Air Quality Compliance Program (Line item 1.26)

A. This variance is a result of the timing of Plant Daniel's Unit 1 and Unit 2 scrubbers and their common scrubber equipment all being placed in-service in November 2015. Unit 1 and the common equipment were projected to be placed in-service in October 2015 and Unit 2 in-service in November 2015.

Q. How do the actual O&M expenses for the period January 2015 to December 2015 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 $26,094,636**,** as compared to the estimated true-up of $27,076,210. This resulted in a variance of ($981,574) or 3.6% below the estimated true-up. I will address eight O&M projects and/or programs that contribute to this variance: Title V, General Water Quality, Groundwater Contamination Investigation, Above Ground Storage Tanks, Sodium Injection program, FDEP NOx Reduction Agreement, Air Quality Compliance Program, and SO_2 Allowances.

Q. Please explain the variance of $60,481 or 39.2% in (Line item 1.3), Title V.

A. This variance is primarily due to $41,063 of Plant Daniel air emissions fees being charged to the Title V Program instead of the Air Emissions Program. Gulf also incurred $14,760 related to SO2 modeling pursuant to an unanticipated request from the Florida Department of Environmental Protection (FDEP) last August.

Q. Please explain the variance of ($81,254) or (6.1%) in (Line item 1.6), General Water Quality.

A. This line item includes expenses related to Plant Crist's dam safety, ground water monitoring and treatment chemicals. This variance is due to dam safety expenses being less than projected and less sodium bisulfite needed to de-chlorinate cooling water due to the Crist units running less than projected.

Q. Please explain the variance of $366,228 or 8.8% in (Line item 1.7), Groundwater Contamination Investigation.

A. This line item includes expenses related to substation investigation and remediation activities. This variance is also due to additional work being required by the FDEP to complete soil and groundwater assessment studies necessary to comply with the FDEP established Consent Order and to comply with FDEP's established deadline. The cost increase is also from higher than expected excavation volumes of contaminated soil and its related disposal costs.

Q. Please explain the variance of ($76,219) or (39.9%) in (Line item 1.12), Above Ground Storage Tanks.

A. This variance is primarily due to the Plant Crist and Plant Smith petroleum storage tank maintenance work costing less than originally projected. Plant Crist containment cleaning and coating cost was less than originally projected and the plant delayed the installation of an additional containment area. Plant Smith was also able to postpone maintenance work associated with a concrete containment area until 2016.

Q. Please explain the variance of ($54,537) or (84.8%) 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 and during this period these units have been dispatched less than originally projected.

Q Please explain the variance of $215,469 or 12.0% 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 systems 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 required inspections of the SCR anhydrous ammonia piping.

Q. Please explain the O&M variance ($1,321,653) or (7.8%) 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 Daniel Units 1 and 2 scrubbers, 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 dispatching less than projected for the 4th quarter of 2015 and Plant Daniel's scrubbers being placed in-service on November 30th versus Unit 1 in October and Unit 2 earlier in the month of November. Lower operation of the units at Plant Smith resulted in less urea being needed, as well as less maintenance being required for the equipment.

Q. Please explain the variance of ($108,829) or (38.0) % in SO2 Allowances (Line item 1.27).

A. This variance is due to operations at Plant Crist and Plant Daniel being lower than projected.

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

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of Richard M. Markey
Docket No. 160007-EI
Date of Filing: August 4, 2016

Q. Please state your name and business address.

A. My name is Richard M. Markey, 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. Markey, will you please describe your education and experience?

A. I graduated from Oklahoma State University, Stillwater, Oklahoma, in 1983 with a Bachelor of Science degree in Geology and a minor in Petroleum Engineering Technology. I also hold a Master’s degree in Civil Engineering from Florida State University, Tallahassee, Florida. Prior to joining Gulf Power I worked in the Oil & Gas industry, Environmental Consulting and Florida Department of Environmental Regulation. In October 1994, I joined Gulf Power Company as a Geologist and have since held various positions with increasing responsibilities such as Air Quality Engineer, Supervisor of Land & Water Programs, and Manager of Land and Water Programs. In 2016, 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. Mr. Markey, 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 2016. This true-up is based on six months of actual data and six months of estimated data.

Q. Mr. Markey, please compare Gulf's recoverable environmental capital costs included in the estimated true-up calculation for the period January 2016 through December 2016 with the approved projected amounts.

A. As reflected in Mr. Boyett's Schedule 6E, the recoverable capital costs approved in the original projection total $154,168,452 as compared to the estimated true-up amount of $163,602,598. This results in a variance of $9,434,146 or 6.1%.

Q. Are there any factors that impact multiple capital projects?

A. Yes. The recoverable capital costs included in the estimated true-up calculation are approximately $9,434,146 more than the capital costs included in the 2016 Projection filing. One driver that impacts multiple capital projects is the difference between the weighted average cost of capital (WACC) used in the 2016 Projection filing versus the WACC applied to the July through December 2016 period in this 2016 Estimated/Actual True-up filing. In accordance with Commission Order No. PSC-12-0425-PAA-EU, the 2016 Projection filing used the WACC presented in Gulf's May 2015 Earnings Surveillance Report for January through December 2016. In this 2016 Estimated/Actual True-Up filing, the projected July through December 2016 period uses the WACC presented in Gulf's May 2016 Earnings Surveillance Report. After taking this item into consideration, there is a positive variance of approximately $10,683,224 that is largely attributed to six capital projects: 1) CEMS – Plants Crist, Scholz, Smith, & Daniel ($126,924); 2) Smith Water Conservation $127,401; 3) Crist FDEP Agreement for Ozone Attainment $468,939; 4) Air Quality Compliance Program $10,414,943; 5) Coal Combustion Residual ($358,885) and 6) Effluent Limitations Guidelines $101,669. The variances attributed to these programs will be discussed below.

Q. Please explain the capital variance of ($126,924) or (12.1%) reflected in CEMS – Plants Crist, Scholz, Smith, & Daniel (Line Item 1.5).

A. The line item variance is due to a CEMS upgrade scheduled to be in-service in July 2016 that has been cancelled. The MATS CEMS monitoring is a separate program in the Air Quality Compliance Program and is discussed later. On December 9, 2015 Gulf received approval from the Environmental Protection Agency (EPA) that allows Plant Crist to operate in bypass mode without the need for CEMS or MATS CEMS monitoring upgrades when combusting natural gas. The CEMS upgrade project that was cancelled would have installed SO2, NOx, CO2 and flow monitoring on each unit, therefore the CEMS upgrade costs of $3 million was not incurred.

Q. Please explain the capital variance of $127,401 or 9.1% reflected in the Smith Water Conservation Program (Line Item 1.17).

A. This variance is due to a calculation error in depreciation expense made in Gulf's projection filing in docket 150007-EI, offset by the delay of the in-service date for Plant Smith's Unit 3 Reclaimed Water Project. In Gulf's projection filing, the depreciation rate of 3.3% for PE 1601 – Smith Unit 3 Reclaimed Water Project, which had a projected in-service date of January 2016, was omitted. This error in the calculation of depreciation expense is offset by a reduction in expense resulting from the delay of the in-service date of the project to August 2016.

Q. Please explain the capital variance of $468,939 or 4.0% reflected in the Crist FDEP Agreement for Ozone Attainment Program (Line Item 1.19).

A. This variance is primarily due to underestimated depreciation expense for this program in Gulf's projection filing in docket 150007-EI. In Gulf's projection, the depreciation for PE 1287 - Plant Crist 4-6 NOx Reduction was inadvertently not captured in the revenue requirements calculation which accounts for $459,626 of the variance.

Q. Please explain the capital variance of $10,414,943 or 8.3% reflected in the Air Quality Compliance Program (Line Item 1.26).

A. The line item variance is primarily due to the rededication of Gulf's ownership in Plant Scherer Unit 3 to serve native load customers. For this true up filing, Gulf has included capital investment of $184,452,711 associated with a baghouse, MATS controls, Selective Catalytic Reduction (SCR), and scrubber installed at Plant Scherer Unit 3, none of which are currently being recovered through Gulf's base rates. These environmental activities are necessary for Plant Scherer Unit 3 to maintain compliance with applicable environmental requirements. Offsetting the Scherer investment are Plant Crist's MATS CEMS upgrade and Plant Daniel's scrubber capital expenditures. The Plant Crist MATS CEMS upgrade of $3.6 million was cancelled due to Gulf receiving an approval from EPA that allowed Gulf to operate in bypass mode without the need for MATS mercury or particulate monitoring in the bypass stacks or at the exit of the units while combusting natural gas. Plant Daniel's 2016 scrubber capital expenditures are currently estimated at $3.3 million versus the $8.5 million originally projected. The Plant Daniel scrubbers were placed in-service November 30, 2015 and subsequent 2016 capital start-up and final grading costs were less than originally anticipated.

Q. Please explain the capital variance of ($358,885) or (77.7%) reflected in the Coal Combustion Residual (CCR) (Line Item 1.28).

A. The line item variance is primarily due to a delay in the start of Plant Smith's CCR waste water management system. This CCR waste water management system in-service date has been delayed due to the delay in the closure of Plant Smith's ash pond. Engineering and construction on the CCR waste water management system will begin in late 2016. The start date of the construction activities for the closure of Plant Smith's ash pond is scheduled to be December 2017. Plant Scherer will have capital expenditures associated with CCR land acquisitions, CCR ash management system and CCR waste water management system in the amount of $636,494.

Q. Please explain the capital variance of $101,669 reflected in the Effluent Limitations Guidelines (ELG) (Line Item 1.29).

A. The variance in the ELG program is due to moving the 2016 projected costs for the Plant Crist bottom ash handling and wastewater treatment systems from the CCR Program to the ELG Program. On November 3, 2015 the Environmental Protection Agency (EPA) published the final Steam Electric Effluent Guidelines rule in the Federal register. For coal-fired units with a total nameplate generating capacity of greater than 50 MW, the rule limits the discharge of bottom ash transport water (BATW) to transport water used in a FGD scrubber and discharges from minor leaks and maintenance events. Gulf's 2016 projected expenditures for the Effluent Limitations Guidelines program are associated with the new Plant Crist bottom ash handling system and wastewater treatment system. Both projects are required to eliminate the discharge of bottom ash transport water at Plant Crist. The projected 2016 expenditures for both ELG projects were previously approved as part of Gulf's Coal Combustion

Residual program in Order No. PSC-15-0536-FOF-EI. After reviewing the final requirements of the ELG rule, Gulf believes the costs are more appropriately classified under the ELG program.

Q. How do the estimated/actual 2016 O&M expenses compare to the original 2016 projections?

A. Mr. Boyett's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated at $30,673,040 as compared to $49,495,405 the amount projected in the 2016 Projection Filing for a variance of ($18,822,364) or (38.0%). This variance is net after inclusion of recoverable environmental O&M expenses for the current period at Plant Scherer due to rededication of Gulf's ownership in this facility to serving the native load customers for whom it was originally purchased and built. I will address six O&M projects and programs that mostly contribute to this variance: Air Emission Fees, Emissions Monitoring, FDEP NOx Reduction Agreement, Air Quality Compliance Program, Coal Combustion Residual, and SO2 Allowances. I will note how the Scherer expenses impacted the variance in these programs where appropriate. Plant Scherer's Unit 3 also has annual costs associated with three other programs - General Water Quality in the amount of $1,504, Lead and Copper in the amount of $228, and General Solid and Hazardous Waste in the amount of $4,750. None of these three programs has a material variance with or without inclusion Plant Scherer's Unit 3 cost.

Q. Please explain the O&M variance of ($104,336) or (18.6%) in (Line Item 1.2), the Air Emission Fees.

A. The Air Emission Fees are based on actual emissions. The variance is primarily due to the units operating less than expected. Plant Scherer's Unit 3 Air Emission Fees represents $17,195 of the costs included in this line item.

Q. Please explain the O&M variance of ($111,760) or (13.7%) in (Line Item 1.5), the Emissions Monitoring program.

A. The Emissions Monitoring variance is primarily due to Plant Crist emissions testing charges costing less than projected. Plant Scherer's Unit 3 Emission Monitoring program represents $13,172 of the costs included in this line item.

Q. Please explain the O&M variance of $288,573 or 30.3% 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 reassigning $182,170 of outage cost from Plant Crist's Unit 6 SCR, which is in the Air Quality Compliance Program, to Plant Crist's Unit 7 SCR. The remainder of the variance is repairs of Plant Crist's Unit 7 SCR elevator.

Q. Please explain the O&M variance ($7,513,556) or (27.7%) 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, Plant Daniel scrubbers, the Smith Units 1 and 2 SNCRs, and Plant Scherer's baghouse, MATS controls, SCR, and scrubber. 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 three budget items. First, Plant Daniel's scrubber expenses are under budget by $6.5 million due to lower utilization of the coal units. Second, $1.7 million of expenses for Plant Smith were budgeted to this line item in Gulf's projection filing. The Plant Smith Units 1 and 2 were retired as of March 2016 and these cost will not be incurred. Partially offsetting these reductions are Plant Scherer's Unit 3 expenses for the Air Compliance Program projected to be $947,062.

Q. Please explain the variance of ($11,123,657) or (88.6%) in Coal Combustion Residual (Line Item 1.23).

A. The Coal Combustion Residual (CCR) line item includes O&M expenses 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 regulatory compliance obligations are pursuant to either the CCR rule adopted last year or in permit requirements added by the State 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. Approximately $12.2 million of the variance is due to delays in the Plant Scholz pond closure. The closure schedule shifted due to additional time needed for the FDEP to review and approve Gulf's proposed closure plan. Once FDEP approval is achieved, Gulf will move forward with pond closure activities. Plant Scherer's Unit 3 expenses for the CCR Program are projected to be $1,207.

Q. Please explain the variance of ($192,424) or (85.1%) in SO2 Allowances (Line Item 1.27).

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
Richard M. Markey
Docket No. 160007-EI
Date of Filing: September 1, 2016

Q. Please state your name and business address.

A. My name is Richard M. Markey, 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. Markey, will you please describe your education and experience?

A. I graduated from Oklahoma State University, Stillwater, Oklahoma, in 1983 with a Bachelor of Science degree in Geology and a minor in Petroleum Engineering Technology. I also hold a Master's degree in Civil Engineering from Florida State University, Tallahassee, Florida. Prior to joining Gulf Power I worked in the Oil & Gas industry, Environmental Consulting and Florida Department of Environmental Regulation. In October 1994, I joined Gulf Power Company as a Geologist and have since held various positions with increasing responsibilities such as Air Quality Engineer, Supervisor of Land & Water Programs, and Manager of Land and Water Programs. In 2016, 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 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. Mr. Markey, 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 2017 through December 2017, including environmental compliance costs for Gulf's ownership portion of Plant Scherer Unit 3 and related common facilities at Plant Scherer serving native load customers (collectively "Scherer" or "Scherer 3").

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

A. Yes, I have two exhibits. The first exhibit (RMM-1) includes Schedule 5P - Description and Progress Report of Environmental Compliance Activities and Projects. The second exhibit (RMM-2) consists of the following documents:

- Schedule 1- Plant Scherer Existing Air Quality Compliance projects

- o Georgia Multipollutant Control for Electric Utility Steam Generating Units
- o Plant Scherer Title V permit
- o Plant Scherer NPDES permit
- o Plant Scholz NPDES permit
- o Plant Scholz NPDES permit modification
- o Plant Scholz closure plan approval

Counsel: We ask that Mr. Markey's exhibit consisting of one schedule be marked as Exhibit No. _____ (RMM-1). We ask that Mr. Markey's exhibit consisting of one schedule and six documents be marked as Exhibit No. _____ (RMM-2).

CAPITAL

Q. Mr. Markey, 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 and 4P of Gulf Witness Boyett's Exhibit CSB-3 and my Schedule 5P included in my Exhibit RMM-1. 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 six programs that were previously approved by the

Commission with activities that have projected capital expenditures during 2017. These programs include: Continuous Emission Monitoring Systems (CEMS), Smith Water Conservation, Crist FDEP Agreement for Ozone Attainment, Air Quality Compliance Program, Coal Combustion Residuals, and Steam Electric Power Effluent Limitations Guidelines and Standards (ELG).

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

A. Yes, all of these programs have been approved. Gulf is now including environmental compliance costs associated with Scherer 3. The environmental capital expenditures for Scherer 3 are included in the Air Quality Compliance Program and the Coal Combustion Residuals line items and will be discussed as part of the description of these line items.

Q. Mr. Markey, please describe the projected 2017 capital expenditures for Continuous Emission Monitoring Systems (CEMS) (Line Item 1.5).

A. Gulf plans to replace the existing Plant Crist CEMS monitors that are located on the scrubber stack and upgrade Plant Crist Unit 7 flue gas monitors during 2017. The existing monitors are approaching the end of their projected useful life and need to be replaced. Expenditures associated with these activities reflected in the 2017 projection filing are $517,000.

Q. Mr. Markey, 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, piping, and initial equipment needed for the pump station. During the remainder of 2016 and 2017, Gulf will obtain additional operational data required to design the final pump station, wastewater treatment equipment, additional piping and associated storage capacity. Gulf also plans to begin construction of the final pump station and wastewater equipment during 2017. Expenditures associated with these activities reflected in the 2017 projection filing are $1.5 million.

Q. Mr. Markey, please describe the projects included in the 2017 projection for the Crist FDEP Agreement for Ozone Attainment (Line Item 1.19).

A. Gulf plans to replace the Plant Crist Unit 7 SCR silo unloader conveyor during 2017. This project includes maintenance and replacement for components on the silo unloader conveyor system. More specifically, this line item includes the replacement of internal parts of the conveyor system, the canvas liners, and the unloading chute braking cables. The projected 2017 expenditures for this line item are $362,250.

Q. Please describe the projected capital expenditures for the Air Quality Compliance program (Line Item 1.26).

A. Costs associated with the Scherer 3 baghouse, SCR, and scrubber projects as well as associated equipment have been included as part of Gulf's ECRC

Air Quality Compliance Program. A summary of the regulations that required these projects as well as the date each project was placed in-service is provided in Schedule 1 of my Exhibit RMM-2.

The 2017 projected expenditures for the Air Quality Compliance program include costs associated with the following: Plant Crist SCR ammonia system, Plant Crist and Plant Daniel scrubbers, the Plant Daniel activated carbon injection system, as well as the Plant Scherer 3 scrubber and SCR. More specifically, this line item includes upgrades to the control system for the Plant Crist SCR ammonia unloading system, installation of an inlet mercury monitor for the Plant Crist scrubber, replacement of the scrubber filter feedwater valve, and design costs to increase the capacity of the Plant Crist scrubber wastewater treatment plant. Plant Scherer plans to replace the Scherer 3 scrubber booster fan hub and a layer of the Scherer 3 SCR catalyst during 2017. The projected 2017 expenditures for this line item total $3,313,479.

Q. Mr. Markey, please describe the projects included in Gulf's 2017 projection for the Coal Combustion Residuals capital program (Line Item 1.28).

A. Line Item 1.28 is related to the regulation of Coal Combustion Residuals (CCR) by the United States Environmental Protection Agency ("EPA") and the Florida Department of Environmental Protection ("FDEP"). For Gulf's generating plants, these regulatory compliance obligations are pursuant to either the CCR rule adopted in April of 2015 or through new requirements added by FDEP to the National Pollutant Discharge Elimination System

(NPDES) permits issued for each of Gulf's Florida generating facilities pursuant to authority granted under the Clean Water Act. The CCR rule is located in Title 40 Code of Federal Regulations (CFR) Parts 257 and 261. The projected 2017 expenditures for this line item total $6,005,706.

During 2017, Gulf will complete engineering and design of the Plant Scherer and Plant Smith CCR wastewater treatment systems required for the ash pond closure projects. Plant Smith plans to begin construction of a CCR wastewater treatment system during 2017 to support the Plant Smith ash pond closure project that is scheduled to begin during fourth quarter 2017.

As discussed in Gulf's preliminary list of new projects filing, the Plant Scherer ash pond is scheduled to cease operations and stop receiving coal ash within the next three years. Ash pond closure will require several years of construction and related closure activities. During the 2016-2017 timeframe, Plant Scherer will acquire additional land to accommodate ash pond closure and will move forward with engineering in order to be able to utilize Cell 3 of the gypsum landfill area for ash storage. During 2017, Plant Scherer will finalize design of a project to convert Scherer 3 to a dry bottom ash handling system and plans to start construction of that project during the Fall of 2017.

Q. Mr. Markey, please provide an update of the 2017 activities planned for the Steam Electric Power Effluent Limitations Guidelines and Standards (ELG) program (Line Item 1.29).

A. On November 3, 2015 the Environmental Protection Agency (EPA) published the final Steam Electric Power Effluent Limitations Guidelines and Standards (ELG) rule in the Federal register. For coal-fired units with a total nameplate generating capacity of greater than 50 MW, the rule limits the discharge of bottom ash transport water (BATW), to transport water used in a Flue Gas Desulfurization (FGD) scrubber and discharges from minor leaks and maintenance events. All three of Gulf's active coal fired generating plants are subject to the new regulatory requirements.

Gulf's 2017 projected expenditures for the ELG program are associated with the new Plant Crist bottom ash handling system and wastewater treatment system. Both projects are required to eliminate the discharge of bottom ash transport water at Plant Crist. This project will also assist Gulf with meeting ELG compliance limits for other waste water streams. During 2017, Gulf will be completing construction of two underground injection wells at Crist that will be used for bottom ash wastewater disposal. Gulf will begin design work for expansion of the injection well pump station and continue engineering and design of the Plant Crist bottom ash handling system. The projected 2017 expenditures for this line item total $9,147,697.

Q. Mr. Markey, are you including the purchase of allowances in your 2017 projection filing?

A. No, we are not currently projecting the need to purchase additional allowances during 2017.

Operation and Maintenance (O&M)

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 programs listed on Schedule 2P have been approved for recovery through the ECRC in past proceedings other than the Plant Scholz CCR unit closure costs that were deferred in Order No. PSC-15-0536-FOF-EI. As noted in the Order, costs associated with the Scholz CCR unit closure were deferred until after Gulf submitted a closure plan to FDEP for review and approval. In addition, costs associated with Scherer 3 are requested in this proceeding and will be discussed as part of my responses regarding the associated ECRC O&M line items.

Q. Please provide an update on the status of the Plant Scholz CCR unit closure project?

A. The Plant Scholz CCR closure project covers activities and costs for the closure of the CCR pond at Plant Scholz. The FDEP issued NPDES permit No. FL0002283-004 for Plant Scholz on September 23, 2010. General Condition IX.15 of this permit required Gulf to provide written notice to the FDEP at least 60 days before inactivation or abandonment of a wastewater facility. Thus, on May 8, 2015 in accordance with this condition, Gulf gave notice to the FDEP of its plans to inactivate the CCR pond during the upcoming permit cycle. Gulf also requested the FDEP address the closure of the Plant Scholz CCR pond in the NPDES renewal permit for Plant Scholz which was then expected to be issued by the FDEP in the third quarter of 2015. The NPDES industrial wastewater renewal permit for Plant Scholz (FL0002283-005) was issued on October 20, 2015 (See Exhibit RMM-2) and required closure of the existing on-site ash pond during the 2015-2020 permit cycle. This permit also required Gulf to submit a closure plan to the FDEP for its approval.

During the time that Gulf and the FDEP were addressing the NPDES renewal permit conditions related to the closure of the Scholz CCR pond, Gulf was also involved in a lawsuit over the Scholz CCR pond. While not binding on the FDEP, Gulf was able to settle the lawsuit on terms that Gulf expected would satisfy FDEP requirements to close the Plant Scholz CCR pond. Gulf's expectations of how it would be required to close the CCR pond came from years of experience with the Plant Scholz CCR pond facilities as well as known NPDES legal/technical requirements and information learned from discussions with the FDEP on what might be needed to achieve their approval of a closure plan.

Gulf submitted the Plant Scholz closure plan to FDEP on May 26, 2016 and received approval of a closure plan on August 26, 2016. Gulf also received a draft NPDES permit modification on August 25, 2016, which addresses the wastewater portions of the closure project. This draft was noticed on August 30, 2016. Upon final issuance of the NPDES permit modification, Gulf will move forward with activities required for closure. These activities include the construction of an industrial wastewater pond, construction of groundwater control technologies (a groundwater cut-off wall), construction of a stormwater management system, removing CCR material from portions of the existing pond, transferring CCR material upland to a dry stack area primarily within the footprint of the pond, and installing a wastewater treatment system and new groundwater monitoring wells. The expenses associated with the Plant Scholz CCR pond will be reflected in Operation and Maintenance (O&M) Line Item 1.23 discussed below.

Q. Please describe the O&M activities included in the air quality category for 2017.

A. There are five O&M activities included in the air quality category that have projected expenses in 2017. 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, also known as Title V fees, that are payable to the FDEP, the Mississippi Department of Environmental Quality, and the Georgia Environmental Protection Division. The expenses projected for the 2017 recovery period total $257,118, which includes $22,800 for Scherer 3. Payment of the Plant Scherer Title V fees is required in the Plant Scherer Title V permit number 4911-207-0008-V-03-0, Condition 8.4.1 and Chapter 391-3-1-.03(9) of the Georgia Rules for Air Quality Control. The Title V permit is provided in my Exhibit RMM-2.

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 2017 estimated expenses for the Title V Program are $189,872.

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 $500.

Emission Monitoring (Line Item 1.5) on Schedule 2P reflects an ongoing O&M expense associated with the Continuous Emission Monitoring equipment as required by the CAAA. These expenses are incurred in response to EPA's requirements that the Company perform Quality Assurance/Quality Control (QA/QC) testing for the CEMS, including Relative Accuracy Test Audits (RATAs) and Linearity Tests. The expenses expected to be incurred during the 2017 recovery period for these activities total $816,178 which includes $33,301 associated with Scherer 3. Part 5 of the Plant Scherer Title V permit (Permit number 4911-207-0008-V-03-0) outlines the emission monitoring requirements which include continuous monitoring for NOx, SO_2, and opacity. Continuous monitoring for mercury is required by the MATS rule (40 CFR Part 63 Subpart UUUUU).The Title V permit is provided in my Exhibit RMM-2.

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 for ozone attainment. 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 2017 recovery period total $898,852.

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 and Assessment, Surface Water Studies, the Cooling Water Intake Program, the Impoundment Integrity Program, and Stormwater Maintenance. The expenses expected to be incurred during the projection period for this line item totals $2,852,222 which includes $36,952 for Gulf's ownership portion of Scherer 3. The Scherer 3 costs are for materials used as needed to meet the discharge limits included in the Plant Scherer NPDES industrial wastewater permit (Permit Number GA0035564). The NPDES wastewater permit is provided in my Exhibit RMM-2.

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 $3,241,599 of incremental expenses for this line item during the 2017 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 $39,500 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 $8,000 during the 2017 projection period.

Line Item 1.23, is the Coal Combustion Residuals (CCR) program that includes expenses related to the regulation of Coal Combustion Residuals by the United States Environmental Protection Agency ("EPA") and the Florida Department of Environmental Protection ("FDEP"). During 2017, the Plant Scholz and Plant Smith CCR closure projects will be under construction and Gulf will continue its ongoing CCR groundwater monitoring and engineering inspections. The 2017 expenses projected for the CCR line item total $27,418,426 which includes $ 1,401 for Plant Scherer CCR groundwater monitoring.

The Scholz CCR unit closure includes the construction of an industrial wastewater pond, construction of groundwater control technologies (a groundwater cut-off wall), construction of a stormwater management system, removing CCR material from portions of the existing pond, transferring CCR material upland to a dry stack area primarily within the footprint of the pond, and installing a wastewater treatment system and new groundwater monitoring wells. The 2017 expenses for the Plant Scholz CCR closure are projected to be $26,191,933.

The Smith pond closure project is scheduled to start construction in the last quarter of 2017. The Smith pond closure includes the construction of industrial wastewater ponds, a wastewater treatment system, groundwater control technologies, removal of CCR material from portions of the pond, transferring CCR material upland to a dry stack area within the footprint of pond and capping the dry stack area with closure turf material. The 2017 expenses associated with the Plant Smith CCR closure are projected to be $459,000.

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 2017 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 $1,142,225 in 2017.

Q. Are there any other O&M activities that have been approved for recovery that have projected expenses?

A. There are six other O&M activities that have been approved in past proceedings which have projected expenses during 2017. They are the Above Ground Storage Tanks program, the Sodium Injection System, the Air Quality Compliance Program, Smith Water Conservation, Emission Allowances, and Crist Water Conservation.

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 $80,204 are projected to be incurred during 2017.

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. Expenses totaling $75,494 are projected to be incurred during 2017 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 and expenses associated with Gulf's ownership portion of the Scherer 3 baghouse, SCR, and scrubber as well as associated equipment. A summary of the regulations that required each Plant Scherer Air Quality control project is provided on Schedule 1 which is included in my Exhibit RMM-2.

Anhydrous ammonia, hydrated lime, urea, limestone and general O&M expenses are included in the Air Quality Compliance Program line item. The projected 2017 expenses for this line item total $24,042,457 which includes $1,614,583 for expenses associated with Gulf's ownership portion of the Scherer 3 projects. The projected cost is $10,172,338 for limestone costs associated with operation of the Plant Crist, Plant Daniel, and Plant Scherer 3 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 systems, such as piping, valve maintenance and pump replacements. Expenses totaling $403,943 are projected to be incurred during 2017 for this line item.

Q. What activities are included in the Smith Water Conservation line item (Line Item 1.24)?

A. The Smith Water Conservation line item includes general O&M expenses associated with the Plant Smith deep injection well system that will be placed in-service during 2016 as part of the Plant Smith Reclaimed Water capital project. The projected costs include sampling and analytical charges, chemicals, and mechanical integrity testing expenses required by our FDEP permit. Gulf was granted approval for recovery of the Plant Smith Reclaimed Water project in FPSC Order No. PSC-09-0759-FIF-EI. Expenses totaling $234,000 are projected to be incurred during 2017 for this line item.

Q. Please describe the emission allowance line item (Line Item 1.28).

A. This line item includes projected allowance expenses for Gulf's generation. Line Item 1.28 includes $51,310 of projected expenses for SO_2 allowances during 2017 which includes $2,740 for Scherer 3.

Q. Do each of the capital projects and O&M activities that have projected costs in 2017 meet the ECRC statutory guidelines?

A. Yes. The projects included in Gulf's 2017 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. Markey, 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. 160007-EI
Date of Filing: April 1, 2016

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 of Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist. I worked in Forecasting 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 in 2014. My responsibilities include supervision of tariff administration, calculation of cost recovery factors, and oversight of 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 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.

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 2015 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 final ECRC true-up amount for the period ending December 31, 2015, to be refunded or collected in the recovery period beginning January 2017?
A. A refund in the amount of $3,061,120 was calculated, which is reflected on line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $3,061,120 to be refunded was calculated by taking the difference between the estimated January 2015 through December 2015 under-recovery of $1,699,128 as approved in FPSC Order No. PSC-15-0536-FOF-EI, dated November 19, 2015, and the actual over-recovery of $1,361,992, 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 over-recovery of environmental costs for the period January 2015 through December 2015. Schedule 3A of my exhibit is the calculation of the interest provision on the average true-up balance. This method 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 2015 through December 2015 with the estimated/actual O&M expenses approved in conjunction with the November 2015 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 2015 through December 2015 compares the actual recoverable costs related to investment with the estimated/actual amount approved in conjunction with the November 2015 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 32 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 28 of Schedule 8A show the investment and associated costs related to capital projects, while pages 29 through 32 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 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. 160007-EI
Date of Filing: August 4, 2016

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 2016 through December 2016 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 2016 through December 2016 period to be addressed in 2017 ECRC factors?

A. The estimated true-up for the current period is an over-recovery of $7,840,455 as shown on Schedule 1E. This is based on six months of actual data and six months of estimated data. The estimated true-up over-recovery includes the jurisdictional revenue requirements associated with the rededication of the portion of Scherer Unit 3 available to serve retail customers. This amount will be added to the 2015 final true-up over-recovery amount of $3,061,120. The total net true-up over-recovery of $10,901,575 will be addressed in Gulf's proposed 2017 ECRC factors. The detailed calculations supporting the estimated true-up for 2016 are contained in Schedules 2E through 8E. If this Commission allows for the recovery of Scherer Unit 3's environmental revenue requirements through some other cost recovery mechanism, the resulting estimated true-up amount for the current period 2016 is an over-recovery of $19,111,332.

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

A. Schedule 2E shows the calculation of the estimated over-recovery of environmental costs for the period January 2016 through December 2016. 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 2016 through December 2016 to the projected O&M expenses approved by the Commission in Docket No. 150007-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. Emission allowance expenses and the amortization of gains on emission allowances are included with O&M expenses. Mr. Markey 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 2016 through December 2016 compares the estimated/actual investment-related recoverable costs to the projected amount approved in Docket No. 150007-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. Markey 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 33 pages that provide the monthly calculations of recoverable costs associated with each capital project 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 29 of Schedule 8E show the investment and associated costs related to capital projects, while pages 30 through 33 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 2016 through June 2016 is based on the weighted average cost of capital (WACC) presented in Gulf's May 2015 Earnings Surveillance Report. For July 2016 through December 2016 the rate of return used is the WACC presented in Gulf's May 2016 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. 160007-EI
Date of Filing: September 1, 2016

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 2017 through December 2017.

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 9 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-3).

Q. What environmental costs is Gulf requesting recovery of through the Environmental Cost Recovery Clause (ECRC)?

A. As discussed in the testimony of Gulf Witness Richard M. Markey, 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 environmental compliance operating expenses and capital costs provided by Mr. Markey include the portion of Scherer Unit 3 environmental investment and related expenses that serves Gulf’s native load customers (Scherer 3). This portion includes 52 percent of the environmental costs of Gulf’s interest in Plant Scherer for the period January 1, 2016 through May 31, 2016, and 76 percent of those costs beginning June 1, 2016. The costs identified for recovery through the ECRC are not currently being recovered through base rates or any other cost recovery mechanism and, in the case of Scherer 3, exclude the amounts recovered through interim long-term wholesale contracts.

Q. How was the amount of projected Operations and Maintenance (O&M) expenses to be recovered through the ECRC calculated?

A. Mr. Markey has provided projected recoverable O&M expenses for January 2017 through December 2017, including the environmental expenses associated with Scherer 3. 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, 4P and 9P 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. Schedule 9P shows Scherer 3 projected plant-in-service, accumulated depreciation and the resulting net plant balances for the period ending 2017. Schedules 3P and 4P also include the calculation of the jurisdictional amount of recoverable revenue requirements, including the Scherer 3 capital investment at its depreciated net book value. To prepare these schedules, Mr. Markey provided 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, including Scherer 3, 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 projected applicable millage rate to the ECRC apportioned assessed value.

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 2016 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, 2017 through December 31, 2017.

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

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 $1/13^{th}$ energy allocator. The use of this allocator is consistent with cost-of-service studies approved in Gulf's prior base rate cases. The calculation of this breakdown is shown on Schedule 4P and summarized on Schedule 3P.

Q. What is the total amount of projected recoverable costs related to the period January 2017 through December 2017?

A. The total projected jurisdictional recoverable costs for the period January 2017 through December 2017 is $218,646,595 as shown on line 1c of Schedule 1P of Exhibit CSB-3. This amount includes costs related to O&M activities of $60,022,816 and costs related to capital projects of $158,623,778, 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 2017 through December 2017, and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $207,894,596 for the period January 2017 through December 2017, as shown on line 5 of Schedule 1P of Exhibit CSB-3. This amount includes the recoverable costs related to the projection period offset by the total over-recovery true-up amount of $10,901,575. 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 the supporting data presented in accordance with 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 2015 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C. 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 $35,806,588 for the period January 2017 through December 2017 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 $172,088,008 for the period January 2017 through December 2017 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 on Schedule 7P.

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 $21.58 monthly for the period January 2017 through December 2017.

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 2017 and will continue through the last billing cycle of December 2017.

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

A. Yes.

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 4th day of November, 2016.

Linda Boles

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