BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

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In the Matter of:

DOCKET NO. 20180007-EI

ENVIRONMENTAL COST
RECOVERY CLAUSE.
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VOLUME 1
PAGES 1 through 246

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER JULIE I. BROWN
COMMISSIONER DONALD J. POLMANN
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW G. FAY

DATE: Monday, November 5, 2018

TIME: Commenced: 2:01 P.M.
Concluded: 2:03 P.M.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
114 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
(850) 894-0828

APPEARANCES:

MARIA MONCADA and JOEL BAKER, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

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

RUSSELL A. BADDERS and STEVEN R. GRIFFIN, ESQUIRES, Beggs & Lane, P.O. Box 12950, Pensacola, Florida 32591-2950; JEFFREY A. STONE, ESQUIRE, One Energy Place, Pensacola, Florida 32320, appearing on behalf of Gulf Power Company.

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

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

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

APPEARANCES (CONTINUED):

Florida Industrial Power Users Group.

JAMES W. BREW, OWEN J. KOPON AND LAURA A. WYNN, ESQUIRES, Stone Matheis Xenopoulos & Brew PC, 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, DEPUTY PUBLIC COUNSEL; and PATRICIA A. CHRISTENSEN, ESQUIRE, 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.

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

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

I N D E X

WITNESSES

P R O C E E D I N G S

COMMISSIONER CLARK: All right. No other items, we will proceed to the 07 docket.

I would be really amazed if we make it through this one that fast. All right.

MR. MURPHY: Do you need to catch your breath?

COMMISSIONER CLARK: No, I'm great.

MR. MURPHY: Okay. Great.

There are proposed stipulations for all issues except generic Issues 1 through 4 and 7 for FPL, and company specific issues 10A through D, also for FPL.

The parties either agree or take no position on the proposed stipulations.

All witnesses have been excused except for FPL's Witness Sole.

COMMISSIONER CLARK: All right. Let's move into prefiled testimony.

MR. MURPHY: Staff asks that the prefiled testimony of witnesses Deaton, Menendez, Hill, Swartz, West, Rusk, Carpinone -- I am not sure -- Markey and Boyett be entered into the into the record as though read.

COMMISSIONER CLARK: All right. Prefiled testimony of the witnesses referenced will be inserted into the record as read.

(Prefiled testimony inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20180007-EI

APRIL 2, 2018

Q. Please state your name and address.

A. My name is Renae B. Deaton. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Director, Cost Recovery Clauses, in the Regulatory & State Governmental Affairs Department.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science in Business Administration and a Master of Business Administration from Charleston Southern University. Since joining FPL in 1998, I have held various positions in the rates and regulatory areas. Prior to my current position, I held the positions of Senior Manager of Cost of Service and Load Research and Senior Manager of Rate Design in the Rates and Tariffs Department. I am a member of the Edison Electric Institute ("EEI") Rates and Regulatory Affairs Committee, and I have completed the EEI Advanced Rate Design Course. I have been a guest speaker at Public Utility Research Center/World Bank International

Training Programs on Utility Regulation and Strategy. In 2016, I assumed my current position as Director, Cost Recovery Clauses, where I am responsible for providing direction as to the appropriateness of inclusion of costs through a cost recovery clause 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 ("ECRC") final true-up amount associated with FPL's environmental compliance activities for the period January 2017 through December 2017.

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 RBD-1 consists of nine forms.

- Form 42-1A reflects the final true-up for the period January 2017 through December 2017.
- 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 for the period.
- Form 42-5A provides a summary of actual monthly costs for O&M activities in the period.
- Form 42-6A provides the calculation of variances between actual and

actual/estimated revenue requirements for capital investment projects for the period.

- 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 43 through 45 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 for the period.
- 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 ECRC 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 2017 through December 2017, an over-recovery of $31,572,272, which FPL is requesting be included in the calculation of the ECRC factors for the January 2019 through December 2019 period.

The actual end-of-period over-recovery for the period January 2017 through December 2017 of $60,369,973 (shown on Form 42-1A, Line 3) minus the actual/estimated end-of-period over-recovery for the same period of $28,797,701 (shown on Form 42-1A, Line 6) results in the net true-up over-recovery for the period January 2017 through December 2017 (shown on Form 42-1A, Line 7) of $31,572,272.

Q. Have you provided a schedule showing the calculation of the end-of-period true-up amount?

A. Yes. Form 42-2A, entitled "Calculation of the Final True-up Amount," shows the calculation of the end-of-period true-up over-recovery amount of $60,369,973 for the period January 2017 through December 2017. The $59,791,888 shown on line 5 plus the interest provision of $578,084 shown on line 6, which is calculated on Form 42-3A, results in the final over-recovery of $60,369,973 shown on line 11.

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 2017 through December 2017 compare with FPL's actual/estimated amounts as presented in previous testimony and exhibits?

A. Form 42-4A shows that total actual project O&M was $26,969,636 or 43% lower than projected, and Form 42-6A shows that the total actual revenue requirements (return on capital investments, depreciation and taxes) associated with the project capital investments were $866,185 or 0.5% lower than projected. Individual project variances are provided on Forms 42-4A and 42-6A. Revenue requirements for each capital project for the period January 2017 through December 2017 are provided on Form 42-8A, pages 14 through 42.

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

A. The significant variances in FPL's 2017 recoverable O&M expenses and capital revenue requirements from actual/estimated amounts are associated with the following projects:

O&M Variance Explanations

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

Project expenditures were $322,098 or 20% higher than previously projected. The variance is primarily related to an increase of approximately $203,000 in Martin Plant fuel oil tank maintenance for the purchase of paint that was not included in the original budget. In addition, at Manatee Plant, approximately $92,000 was inadvertently charged to this project that should have been charged to base O&M. A correction was made in March of 2018. Finally, repairs on a tank at the Manatee Fuel Oil Terminal were required following an inspection, resulting in an additional cost of approximately $27,000.

Amortization of Gains on Sales of Emissions Allowances

Gains were $119,218 or 2,789% greater than previously projected. The variance is primarily the result of the sale of FPL's excess Cross State Air Pollution Rule ("CSAPR") Nitrogen Oxides ("NOx") ozone season allowances that was not planned for 2017. Following the conclusion of the CSAPR ozone season and determination of allowances needed for compliance, FPL identified an opportunity to sell excess allowances to a third party in December 2017.

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

Project expenditures were $687,272 or 25% 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 2017.

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

Project expenditures were $119,773 or 12% 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 2017.

Project 21. St. Lucie Turtle Nets

Project expenditures were $53,228 or 48% higher than previously projected. The primary cause of the variance was more algae and jellyfish intrusion than predicted, requiring additional net cleaning.

Project 22. Pipeline Integrity Management

Project expenditures were $229,908 or 57% lower than previously projected. The variance primarily reflects the postponement of a planned in-line inspection due to reduced residual fuel oil use at Martin Plant. This postponement along with confirmatory excavations allowed FPL to demonstrate adequate pipeline integrity to meet rule requirements without performing an in-line inspection in 2017.

Project 24. Manatee Plant Reburn

Project expenditures were $103,915 or 30% lower than previously projected. The variance is primarily due to the postponement of the Manatee Unit 1 overhaul. Inspections and repairs originally planned to occur during the overhaul were deferred to the next planned outage that is now scheduled to begin November 1, 2018.

Project 29. SCR Consumables

Project expenditures were $316,702 or 45% lower than previously projected. The variance is primarily related to reductions in unit operations and chemical costs at the Martin and Manatee combined cycle facilities.

Maintenance costs and reagent use for the Selective Catalytic Reduction ("SCR") at Martin Unit 8 were approximately $117,000 lower than projected due to lower than projected costs for ammonia and outside contractor services as a result of lower than projected actual unit operations.

Costs at Manatee Unit 3 were approximately $200,000 lower than projected due to lower than projected costs for ammonia and reagent system maintenance as a result of reduced unit operations. A required five-year inspection of the tank and piping associated with the SCR identified that no significant repairs were required and resulted in approximately $120,000 reduction from projected maintenance expenses. In addition, a Unit 3 scheduled outage resulted in reduced operation, which required less ammonia to be purchased than projected, resulting in an additional $80,000 savings.

Project 33. MATS Project

Project expenditures were $215,598 or 11% lower than previously projected. The variance is primarily due to reduced chemical consumption for mercury control that resulted from lower than projected actual unit operations at Scherer and St. Johns River Power Park.

Project 37. DeSoto Next Generation Solar Energy Center

Project expenditures were $202,229 or 28% lower than previously projected. The variance is primarily related to reduced payroll and associated employee costs and expenses that occurred from changes that were implemented to FPL's solar staffing model. The original projections were based on the historical staffing model that included separate staffing for the ECRC recoverable solar projects. The new staffing models allow for utilization of employees across several solar sites, such that employees at DeSoto are now shared with other solar sites and the attendant costs are allocated accordingly. Additional reductions were achieved through lower than projected costs for vegetation management contracts at the DeSoto site.

Project 39. Martin Next Generation Solar Energy Center

Project expenditures were $1,392,830 or 37% higher than previously projected. The variance is primarily due to higher than projected maintenance costs associated with solar field array piping and array support structures. As a result of a weld failure that occurred on the solar array heat collector piping, FPL implemented a full-scale countermeasure at a cost of approximately $950,000 for inspections of all welds in 500 acres of the solar field. The remaining $450,000 of increased cost was due to the discovery of a piping support pier issue in a section of the mirror framework. A systematic survey of all 52 miles of piping was completed to determine the extent of pier work that needed to be addressed. A consultant was subsequently hired and a countermeasure implemented at more than 13,000 pier locations.

Project 41. Manatee Temporary Heating System

Project expenditures were $371,365 or 16% lower than previously projected. The variance was primarily due to the following factors: (1) use of on-site dredge material resulted in a $150,000 savings over the original plan to haul dredge material from off-site, (2) costs for project management were shared with two other projects at Canaveral Clean Energy Center resulting in a total savings of $88,000, (3) implementation of improved processes and design changes resulted in a savings of approximately $50,000, (4) the elimination of a planned permit that resulted in a cost saving of approximately $12,000, and (5) a negotiated contractor settlement addressing project change orders resulted in a savings of approximately $52,000.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project expenditures were $26,499,882 or 70% lower than previously projected. As discussed in the testimony of FPL witness Sole, the primary cause of the variance was the deferral of certain activities to 2018 due to delays in the permitting process.

Project 45. 800 MW Unit ESP

Project expenditures were $115,626 or 15% lower than previously projected. The variance is primarily related to lower than expected Electrostatic Precipitators ("ESP") maintenance costs due to lower than projected actual plant operations at the Martin site.

Project 47. NPDES Permit Renewal Requirements

Project expenditures were $66,892 or 55% higher than previously projected. The variance was primarily due to an accelerated schedule for the St. Lucie Plant Chlorine Optimization Study. Approximately $75,000 associated with Phase 2 of the study originally projected for 2018 was incurred in 2017 due to the early completion of Phase 1 in 2017.

Project 50. Steam Electric Effluent Guidelines Revised Rules

Project expenditures were $198,803 or 121% higher than previously projected. The variance was primarily due to higher than forecasted expenditures associated with preliminary engineering studies and investigations necessary to evaluate options to achieve compliance with the current Steam Electric Effluent Guideline limits on fluidized gas desulfurization ("FGD") wastewater, which is associated with the Plant Scherer wet scrubber system. The main focus of these studies was evaluating potential compliance technologies including physical and chemical treatment systems, biological treatment and vapor compression evaporation.

Capital Variance Explanations

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project revenue requirements were $495,747 or 14% lower than previously projected. As discussed in the testimony of witness Sole, the variance is primarily due to deferrals in capital spending from 2017 to 2018 for the Recovery Well System and the Turning Basin and Turtle Point Backfill as a result of delays in the permitting process.

Project 54. Coal Combustion Residuals

Project revenue requirements were $242,966 or 26% lower than previously projected. The variance is due to a deferral of expenditures. The deferred activities included: design, procurement and construction of Scherer Unit 4's dry bottom ash system, rerouting of the waterway from the ash pond, and treatment and discharge of wastewater.

<u>Proposed Accounting for Cooling Tower Repacking Activity Costs</u>

Q. FPL filed a petition on March 5, 2018 requesting to modify the NPDES Permit Renewal Requirement Project to include cooling tower repacking and associated monitoring costs at Plant Scherer Unit 4. Please address how FPL proposes to treat the costs for this modification.

A. The NPDES permit renewal process for Plant Scherer is still in an early stage. Therefore, FPL is not seeking current ECRC recovery of the cooling tower repacking costs. Rather, FPL requests approval to recover those costs through the ECRC only after issuance of the renewed NPDES permit with a requirement to address copper discharges. Prior to that, FPL will exclude the costs incurred for the repacking activity at Plant Scherer Unit 4 from ECRC recoverable accounts and instead will record those costs in base capital accounts. Any associated expenses will likewise be recorded in base expense accounts.

If, as anticipated, the renewed NPDES permit for Plant Scherer includes a condition that requires a reduction in copper concentration (thus confirming the regulatory requirements for the repacking activity), FPL will transfer the balance of all reasonable and prudent costs for the repacking activity from the base capital accounts to ECRC recoverable accounts and begin the normal process of ECRC recovery for those and future reasonable and prudent associated capital costs and O&M expenses.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20180007-EI

July 25, 2018

Q. Please state your name and address.

A. My name is Renae B. Deaton. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Director, Cost Recovery Clauses, in the Regulatory & State Governmental Affairs Department.

Q. Have you previously filed testimony in this docket?

A. Yes.

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 2018 through December 2018. My testimony also provides a revised 2017 final net true-up amount that includes adjustments to the amount filed on April 2, 2018.

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 RBD-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 2018 through December 2018.
- 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 14 through 64) reflects return on capital investments and depreciation by project. Pages 65 through 67 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 rate of return applied to capital investment amounts included for recovery for the period January 2018 through December 2018.

Exhibit RBD-3 in Appendix II provides schedules reflecting the calculation of the revised 2017 final net true-up amount.

Q. Have you made any adjustments to the 2017 final net true-up amount that was filed in this docket on April 2, 2018?

A. Yes. FPL has made the following adjustments that have resulted in a net increase in 2017 jurisdictionalized revenue requirements of $12,163:

- Project 5b - Maintenance of Stationary Above Ground Fuel Storage Tanks – Capital investments of $371,085 associated with two Port Everglades tanks were incorrectly charged to base rates in August 2017. A correction was made to remove the amount from base rates and include in Project 5b. This adjustment resulted in an increase in jurisdictionalized revenue requirements of $12,163.
- Project 8b - Oil Spill Clean-up/Response Equipment – Capital investments of $178,013 associated with Project 23 – Spill Prevention, Controls and Countermeasures were incorrectly charged to Project 8b. A correction was made to remove the amount from Project 8b and include in Project 23. These adjustments did not impact revenue requirements.

These adjustments reduce the actual 2017 end-of-period over-recovery amount, including interest, from $60,369,973 to $60,357,782 and the 2017 final net true-up over-recovery amount, including interest, from $31,572,272 to $31,560,081. Exhibit RBD-3 in Appendix II of my testimony provides the schedules reflecting the calculation of the revised 2017 final net true-up over-recovery amount of $31,560,081.

Q. Please explain the calculation of the Environmental Cost Recovery Clause ("ECRC") Actual/Estimated True-Up amount FPL is requesting this Commission to approve.

A. The Actual/Estimated True-Up amount for the period January 2018 through December 2018 is an under-recovery, including interest, of $5,614,420 (Appendix I, page 1, line 4). This Actual/Estimated True-Up amount is calculated by comparing actual data for January 2018 through May 2018 and revised estimates for June 2018 through December 2018, to original projections for the same period. The under-recovery of $6,713,285 shown on Appendix I, page 2, line 5 plus the interest provision of $1,098,865 shown on line 6, which is calculated on Form 42-3E, results in the final under-recovery of $5,614,420 shown on line 11.

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

A. Yes, with the exception of the costs associated with the Modification to the Manatee Temporary Heating System ("MTHS") project and Approval of the Solar Site Avian Monitoring and Reporting project, for which FPL petitioned on February 12, 2018 and June 13, 2018, respectively.

Q. How do the actual/estimated project costs for January 2018 through December 2018 compare with original projections for the same period?

A. Form 42-4E (Appendix I, page 4) shows that total O&M project costs are $8,510,177 higher than projected, while Form 42-6E (Appendix I, page 9) shows that total capital investment project costs are $3,484,805 lower than projected. Individual project variances are provided on Forms 42-4E and 42-6E. Revenue requirements for each project for the 2018 actual/estimated period are provided on Form 42-8E (Appendix I, pages 14 through 64).

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

A. The significant variances in FPL's 2018 recoverable O&M expenses and capital revenue requirements from projection amounts are associated with the following projects:

O&M Variance Explanations

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

Project expenditures are $1.1 million or 61% lower than previously projected. The variance is primarily due to the planned retirement of Martin Units 1 and 2 by the end of 2018, which eliminated the need for project activities associated with those units that were included in the original 2018 projections.

Project 22. Pipeline Integrity Management

Project expenditures are $505 thousand or 86% lower than previously projected. The variance is primarily due to the planned retirement of Martin Units 1 and 2 by the end of 2018, which eliminated the need for project activities associated with those units that were included in the original 2018 projections.

Project 29. SCR Consumables

Project expenditures are $185 thousand or 26% lower than previously projected. The variance is primarily related to lower ammonia consumption associated with a reduction in unit operations. In addition, cost estimates for planned outage work, which include SCR annual inspections on Martin Units 8A, B & C, SCR 3-year inspection on Martin Unit 8D, and piping inspections in the fall of 2018 at the Martin site are now projected to be less than originally estimated.

Project 39. Martin Next Generation Solar Energy Center

Project expenditures are $838 thousand or 24% higher than previously projected. The variance is primarily due to the acceleration of the maintenance outage at Unit 8 from 2019 to the fourth quarter of 2018, which also accelerated the outage work.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project expenditures are $9.5 million or 50% higher than previously projected. The variance is primarily due to the deferral of certain activities from 2017 to 2018, as discussed in FPL witness Michael W. Sole’s testimony filed April 2, 2018.

Project 47. NPDES Permit Renewal Requirements

Project expenditures are $189 thousand or 64% higher than previously projected. The variance is primarily related to the installation of chlorine injection pump skids at the St. Lucie Plant. These pumps are projected to cost effectively optimize chlorine use in the intake cooling water system, which is a requirement of the facility's Florida Department of Environmental Protection Industrial Wastewater Facility Permit No. FL0002208. Study work on chlorine optimization of the remaining St. Lucie plant water systems is ongoing and additional activities will likely be identified and implemented prior to completion of the study.

Capital Variance Explanations

Project 3. Continuous Emission Monitoring Systems

Project revenue requirements are estimated to be $81 thousand or 12% lower than previously projected. The variance is primarily related to the replacement of a continuous emissions monitoring system ("CEMS") server at the Sanford Plant in 2017, which was originally projected to occur in 2018. In addition, the Martin Plant Nitrogen Oxide ("NOx") analyzers and CEMS servers on Units 1 & 2 were removed due to dismantlement. These decreases were partially offset by higher than projected costs of NOx analyzers at Martin Units 3 & 4 and the replacement of the CEMS umbilical between the analyzer and the stack at Martin Unit 1.

Project 28. CWA 316(b) Phase II Rule

Project revenue requirements are estimated to be $126 thousand or 61% lower than previously projected. The variance is primarily attributed to lower than estimated costs for construction of the horseshoe crab barrier in 2017, which impacted the beginning balance in 2018.

Project 34. St. Lucie Cooling Water System Inspection & Maintenance

Project revenue requirements are estimated to be $101 thousand or 23% lower than previously projected. The variance is primarily due to suspension of activity associated with the proposed turtle barrier pending receipt of comments from National Marine Fisheries Service and the Florida Fish and Wildlife Conservation Commission on possible alternatives. Test results of the proposed configuration of the turtle barrier showed possible injury to turtles.

Project 41. Manatee Temporary Heating System

Project revenue requirements are $210 thousand or 31% lower than previously projected. The variance is primarily due to the delay of capital spend and in-service dates for the Dania Beach MTHS, which resulted in a reduction in forecasted debt and equity return and depreciation expense. This decrease is partially offset by the addition of the Ft. Myers Plant MTHS as discussed in FPL's April 2, 2018 testimony.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project revenue requirements are $1.8 million or 28% lower than previously projected. As discussed in the testimony of witness Sole filed April 2, 2018, the variance is primarily due to deferrals in capital spending from 2017 to the later part of 2018 for the Turning Basin and Turtle Point Backfill projects as a result of delays in the permitting process.

Project 54. Coal Combustion Residuals

Project revenue requirements are $292 thousand or 10% higher than previously projected. The variance is primarily related to higher than projected engineering and construction costs associated with required wastewater treatment and higher than projected quantities of concrete, steel, piping and installation labor hours associated with ash management activities for Plant Scherer. These increases were partially offset by lower than projected costs associated with deferral of the landfill construction.

Q. Are costs associated with the cooling tower repacking and associated monitoring costs at Plant Scherer Unit 4 included in the NPDES Permit Renewal Requirements project?

A. No. As discussed in my testimony filed in this docket on April 2, 2018, the costs of the cooling tower repacking and associated monitoring costs at Plant Scherer Unit 4 will be excluded from the NPDES Permit Renewal Requirements Project and ECRC recovery until FPL receives the NPDES permit that includes a requirement to address copper discharges.

Q. Was the jurisdictional separation factor used for General Plant costs in this filing approved in Final Order No. PSC-2018-0014-FOF-EI issued on January 5, 2018?

A. No. The projections filed by FPL in Docket 20170007-EI did not include any costs for General Plant; therefore, the General Plant separation factor was not addressed in the order. However, FPL has incurred actual costs associated with General Plant in various ECRC projects during 2018. Therefore, FPL has utilized the General Plant separation factor that was shown on my Exhibit RBD-3, Appendix II "Calculation of the Stratified Separation Factors" filed in Docket No. 20170007-EI. This is consistent with the other separation factors approved for use in Order No. PSC-2018-0014-FOF-EI. The appropriate 2018 separation factor for General Plant (Demand) is 96.9449%.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20180007-EI

AUGUST 24, 2018

Q. Please state your name and address.

A. My name is Renae B. Deaton. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Director of Clause Recovery and Wholesale Rates in the Regulatory & State Governmental Affairs Department.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval FPL's Environmental Cost Recovery Clause ("ECRC") projections and factors for the January 2019 through December 2019 period.

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

A. Yes. The costs being submitted for the 2019 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 exhibit with two appendices:

- Exhibit RBD-4 provides the calculation of FPL's proposed ECRC factors for the period January 2019 through December 2019 and includes PSC Forms 42-1P through 42-8P, which are provided in Appendix I. Appendix II provides the calculation of the stratified separation factors.
    - FPL witness Michael W. Sole is co-sponsoring Form 42-5P (Project Progress Reports).

Q. Have you provided a schedule showing the calculation of projected environmental costs being requested for recovery for the period January 2019 through December 2019?

A. Yes. Form 42-1P (page 1) provides a summary of projected environmental costs being requested for recovery for the period January 2019 through December 2019. Total jurisdictional revenue requirements including true-up amounts and revenue taxes, are $161,536,472 (page 1, line 5). This amount includes the jurisdictional revenue requirements projected for the January 2019 through December 2019 period, which are $187,365,910 (page 1, line 1c), the actual/estimated true-up under-recovery of $5,614,420 for the January 2018 through December 2018 period (page 1, line 2) and the revised final true-up over-recovery of $31,560,081 for the January 2017 through December 2017 period (page 1, line 3). The detailed calculations supporting the 2018 actual/estimated and revised 2017 final true-ups were provided in Exhibit RBD-2 and Exhibit RBD-3 filed on July 25, 2018.

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

A. Forms 42-1P through 42-8P provide the calculation of ECRC factors for the period January 2019 through December 2019 that FPL is requesting this Commission to approve.

Form 42-1P (page 1) provides a summary of projected environmental costs being requested for recovery for the period January 2019 through December 2019.

Form 42-2P (pages 2 through 4) presents the O&M costs associated with FPL's environmental projects for the projected period along with the calculation of the total jurisdictional amount of $36,476,395 for these projects.

Form 42-3P (pages 5 through 7) presents the recoverable amounts associated with capital costs for FPL's environmental projects for the projected period, along with the calculation of the total jurisdictional recoverable amount of $150,889,515.

Form 42-4P (pages 8 through 59) presents the detailed calculation of these recoverable amounts by project for the projected period. Pages 60 through 62 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 42-5P (pages 63 through 129) provides the description and progress of approved environmental projects included in the projected period.

Form 42-6P (page 130) 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 (page 131) presents the calculation of the proposed 2019 ECRC factors by rate class.

Form 42-8P (page 132) presents the capital structure, components and cost rates relied upon to calculate the rate of return applied to capital investments included for recovery through the ECRC for the period January 2019 through December 2019. Pursuant to Order No. PSC-12-0425-PAA-EU issued on August 16, 2012, FPL is using the capital structure and cost rates from the May 2018 Earnings Surveillance Report.

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

A. Yes, with the exception of the costs associated with the Modification to the Manatee Temporary Heating System project and Approval of the Solar Site Avian Monitoring and Reporting project, for which FPL petitioned on February 12, 2018 and June 13, 2018, respectively.

Q. Has FPL accounted for stratified wholesale power sales contracts in the jurisdictional separation of the environmental costs?

A. Yes. FPL has separated the production-related environmental costs based on stratified separation factors that better reflect the types of generation required to serve load under stratified wholesale power sales contracts. The use of stratified separation factors thus results in a more accurate separation of environmental costs between the retail and wholesale jurisdictions.

FPL's sales forecast reflects two stratified wholesale power sales contracts in 2019: (1) a 200 MW intermediate contract with Seminole Electric Cooperative Inc., and (2) a combined intermediate / peaking contract with the Florida Public Utilities Company. The separation factors for the intermediate and peaking strata were calculated in a manner consistent with the separation factors used for the non-nuclear contracts (now expired) in prior base rate cases. The calculations of the stratified separation factors are provided in Appendix II.

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. 20180007-EI

April 2, 2018

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, Actual/Estimated 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 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 present for Commission review and approval DEF's actual true-up costs associated with environmental compliance activities for the period January 2017 - December 2017.

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 four capital projects by site.

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

- Form 42-1A: Final true-up for the period January 2017 - December 2017.
- Form 42-2A: Final true-up calculation for the period.
- Form 42-3A: Calculation of the interest provision for the period.
- Form 42-4A: Calculation of variances between actual and actual/estimated costs for O&M Activities.
- Form 42-5A: Summary of actual monthly costs for the period for O&M Activities.
- Form 42-6A: Calculation of variances between actual and actual/estimated costs for Capital Investment Projects.
- Form 42-7A: Summary of actual monthly costs for the period for Capital Investment Projects.
- Form 42-8A, pages 1-18: Calculation of return on capital investment, depreciation expense and property tax expense for each project recovered through the ECRC.

- Form 42-9A: DEF's capital structure and cost rates.

Exhibit No.___ 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)

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 2017 - December 2017?

A. DEF requests approval of an over-recovery amount of $6,565,806 for the year ending December 31, 2017. 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 2017 - December 2017 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 adjusted net true-up over-recovery amount of $4,814,791 for the period January 2017 - December 2017 reflected on Line 3 of Form 42-1A. This amount is the difference between an actual over-recovery amount of $6,565,806 and an actual/estimated over-recovery of $1,751,015 for the period January 2017 - December 2017, as approved in Order PSC-2018-0014-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 2017 - December 2017 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 $5,602,103 or 13% 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 2017 - December 2017 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 $61,800 or 0.2% 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 1-18. Explanations associated with variances are contained in the direct testimonies of 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 $6,263 or 31% lower than projected. This is primarily due to lower than expected SO_2 Allowance expense.

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. 20180007-EI

July 25, 2018

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. 20180007-EI?

A. Yes, I provided direct testimony on April 2, 2018.

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 2018 through December 2018. I also explain the variance between 2018 actual/estimated cost projections versus original 2018 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 2018 through December 2018.

Q. What is the actual/estimated true-up amount for which DEF is requesting recovery for the period of January 2018 through December 2018?

A. The 2018 actual/estimated true-up is an over-recovery, including interest, of $4,444,194 as shown on Form 42-1E, line 4. This amount is added to the final 2017 true-up over-recovery of $4,814,791 as shown on Form 42-2E, Line 7a, resulting in a net over-recovery of $9,258,985 as shown on Form 42-2E, Line 11. The calculations supporting the 2018 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 2018 through December 2018?

A. The capital structure, components and cost rates relied on to calculate the revenue requirement rate of return for the period January 2018 through December 2018 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 2018 through December 2018 compare with original projections?

A. Form 42-4E shows that total O&M project costs are estimated to be $1,015,382 or 3% higher 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.

Q. How do estimated/actual capital recoverable costs for January 2018 through December 2018 compare with DEF's original projections?

A. Form 42-6E shows that total recoverable capital costs are estimated to be $3,489,542 or 12% 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 Mr. Hill, Mr. Swartz and Ms. West.

Q. Please explain the O&M 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 $11,717 or 45% higher than projected due to higher than projected SO2 allowance expense.

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. 20180007-EI

August 24, 2018

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. 20180007-EI?

A. Yes. I provided direct testimony on April 2, 2018 and July 25, 2018.

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 2019 through December 2019. My testimony also addresses capital and O&M expenses for DEF's environmental compliance activities for the year 2019.

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 0.142 cents per kWh which includes projected jurisdictional capital and O&M revenue requirements for the period January 2019 through December 2019 of approximately $55.8 million associated with a total of 18 environmental projects, and a true-up over-recovery provision of approximately $9.3 million from prior periods. My testimony also supports that projected environmental expenditures for 2019 are appropriate for recovery through the ECRC.

Q. What is the total recoverable revenue requirement for the period January 2019 through December 2019?

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is approximately $55.8 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 2019 through December 2019?

A. The total true-up applicable to this period is an over-recovery of approximately $9.3 million. This amount consists of the final true-up over-recovery of approximately $4.8 million for the period January 2017 through December 2017, and an estimated true-up over-recovery of approximately $4.4 million for the current period of January 2018 through December 2018. The detailed calculation supporting the 2018 estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. __ (CAM-3) filed with the Commission on July 25, 2018.

Q. How will Flue Gas Desulfurization ("FGD") Blowdown Pond Closure costs (Coal Combustion Residual ("CCR") Project 18) be allocated to rate classes?

A. Consistent with CCR O&M costs approved in Order No. PSC-2015-0536-FOF-EI, DEF proposes that O&M costs associated with the FGD Blowdown Pond Closure be allocated to rate classes on an energy basis.

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-2002-1735-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-2003-1348-FOF-EI.

The recovery of sulfur dioxide (SO_2) Emission Allowances (Project 5) was previously approved in Order No. PSC-1995-0450-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, 2015. Consistent with Order No. PSC-2011-0553-FOF-EI, DEF treated the costs associated with unusable NOx emission allowances as a regulatory asset and amortized it over three (3) years, beginning January 1, 2015, until fully recovered 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-2004-0990-PAA-EI and PSC-2018-0014-FOF-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-2007-0922-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-2005-1251-FOF-EI.

The Modular Cooling Tower Project (Project 11) was previously approved in Order No. PSC-2007-0722-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-2008-0775-FOF-EI.

The Mercury Total Maximum Loads Monitoring Program (Project 13) was previously approved in Order No. PSC-2009-0759-FOF-EI.

The Hazardous Air Pollutants (HAPs) ICR Program (Project 14) was previously approved in Order No. PSC-2010-0099-PAA-EI.

The Effluent Limitations Guidelines ICR Program (Project 15) was previously approved in Order No. PSC-2010-0683-PAA-EI.

The Effluent Limitations Guidelines Program (Project 15.1) was previously approved in Order No. PSC-2013-0606-FOF-EI.

The National Pollutant Discharge Elimination System (NPDES) Program (Project 16) was previously approved in Order No. PSC-2011-0553-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-2011-0553-FOF-EI, PSC-2012-0432-PAA-EI and PSC-2014-0173-PAA-EI.

The Coal Combustion Residual (CCR) Rule was previously approved in Order No. PSC-2015-0536-FOF-EI.

Q. What capital structure, components and cost rates did DEF rely on to calculate the revenue requirement rate of return for the period January 2019 through December 2019?

A. DEF used the capital structure, components and cost rates consistent with the language in Order No. PSC-2012-0425-PAA-EU. As such, DEF used the rates contained in its May 2018 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. Does DEF's Weighted Average Cost of Capital ("WACC") comply with paragraph 19 of the 2017 Second Revised and Restated Stipulation and Settlement Agreement ("2017 Settlement")?

A. Yes. The WACC complies with paragraph 19 of the 2017 Settlement approved by the Commission in Order No. PSC-2017-0421-AS-EU.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2019?

A. Yes. Form 42-2P of Exhibit No. __ (CAM-5) summarizes recoverable jurisdictional O&M cost estimates for these projects of approximately $39.4 million.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2019?

A. Yes. Form 42-3P of Exhibit No. __ (CAM-5) summarizes recoverable jurisdictional capital cost estimates for these projects of approximately $25.6 million. Form 42-4P pages 1 through 18 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 2019?

A. The total jurisdictional capital and O&M costs to be recovered through the ECRC are approximately $65.0 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 2018. 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 2018 ECRC billing factors by the various rate classes and delivery voltages?

A. The calculation of DEF's proposed ECRC factors for 2019 customer billings is shown on Form 42-7P in Exhibit No. __(CAM-5) as follows:

RATE CLASS	ECRC FACTORS 12CP & 1/13AD
Residential	0.143 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.143 cents/kWh
@ Primary Voltage	0.142 cents/kWh
@ Transmission Voltage	0.140 cents/kWh
General Service 100% Load Factor	0.141 cents/kWh

General Service Demand	
@ Secondary Voltage	0.141 cents/kWh
@ Primary Voltage	0.140 cents/kWh
@ Transmission Voltage	0.138 cents/kWh
Curtailable	
@ Secondary Voltage	0.137 cents/kWh
@ Primary Voltage	0.136 cents/kWh
@ Transmission Voltage	0.134 cents/kWh
Interruptible	
@ Secondary Voltage	0.138 cents/kWh
@ Primary Voltage	0.137 cents/kWh
@ Transmission Voltage	0.135 cents/kWh
Lighting	0.138 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 2019 and continue through the last bill group for December 2019.

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. 20180007-EI

April 2, 2018

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 15 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 2017 Coal Combustion Residual ("CCR") Rule compliance activities and associated 2017 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 2017 – December 2017 compare to actual/estimated Capital projections for the CCR Rule (Project 18)?

A. The CCR Rule capital variance is $36,197 or 58% lower than projected due to fewer CCR wells required to complete initial groundwater sampling and statistical analysis.

Q. How did actual O&M project expenditures for the period January 2017 – December 2017 compare to actual/estimated O&M projections for the CCR Rule (Project 18)?

A. The CCR O&M variance is $88,951 or 19% lower than projected. This is primarily due to lower than projected actual costs for FGD Blowdown Pond closure plan development, vegetation management for CCR facilities, engineering inspections, and emergency action plan exercises.

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. 20180007-EI

July 25, 2018

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. 20180007-EI?

A. Yes, I provided direct testimony on April 2, 2018.

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 2018 actual/estimated cost projections and original 2018 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 2018 through December 2018.

A. O&M expenditures for CCR are expected to be $544,661 or 155% higher than projected. This is primarily due to the escalation of approximately $565k for flue gas desulfurization ("FGD") dewatering and solids removal, and $109k for groundwater studies into 2018. The FGD dewatering and solids removal support the closure of the FGD blowdown pond, as required under the CCR Rule and the Third Amendment to Consent Order OGC No. 09-3463D. The dewatering and solids removal costs were originally expected to be incurred in 2019 but have been moved into 2018 to help ensure the compliance date requirement is met. The groundwater studies cost is due to the groundwater assessment, which is being undertaken pursuant to the CCR Rule requirements. These were slightly offset by decreases in vegetation management expense during the first half of the year due to dryer than normal conditions.

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. 20180007-EI

August 24, 2018

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. 20180007-EI?

A. Yes. I provided direct testimony on April 2, 2018 and July 25, 2018.

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 2019 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 – Coal Combustion Residual Rule

Q. What are the CCR rule compliance activities and associated costs for which DEF is seeking recovery in 2019?

A. <u>Ash Landfill and Flue Gas Desulfurization ("FGD") Ponds O&M Costs</u>

Various maintenance and repair work is required for the CR ash landfill and FGD ponds to comply with the rule. These include fixing ruts and animal burrows, vegetation management, erosion repairs, fugitive dust mitigation, Emergency Action Plan exercises and updates, and routine weekly inspections. Additionally the rule requires annual inspections of the landfill and FGD ponds by qualified engineers. DEF will also continue to perform the required groundwater monitoring for ash management units, which includes engineering, sampling, analysis, and reporting. Groundwater monitoring in 2019 will also include costs for activities related to assessment of corrective measures and alternative source demonstrations to address groundwater quality exceedances.

Additionally DEF has begun dewatering and solids removal of the FGD ponds to support closure. Total O&M costs are forecasted to be approximately $4.1M.

Ash Landfill Capital Costs

DEF estimates approximately $168k of capital expenditures in 2019 for engineering for design and permitting associated with a potential new lined landfill unit as a possible corrective action measure to address groundwater quality impacts as required for compliance with the CCR Rule.

Q. Please provide an update on the Flue Gas Desulfurization ("FGD") Blowdown Pond Closure.

A. As filed in the Preliminary List of New Projects on July 2, 2018 in this docket, DEF will begin closure of the FGD Blowdown pond, as required under the CCR Rule and the Third Amendment to Consent Order OGC No. 09-3463D (“CO”). Under the CCR Rule, Code of Federal Regulations (CFR) Title 40, Chapter I, Part 257, Subpart D, Section 257.102(e)(3), “closure of the CCR unit has commenced if the owner or operator has ceased placing waste and completes any of the following actions or activities:

(i) Taken any steps necessary to implement the written closure plan required by paragraph (b) of this section;

(ii) Submitted a completed application for any required state or agency permit or permit modification; or

(iii) Taken any steps necessary to comply with any state or other agency standards that are a prerequisite, or are otherwise applicable, to initiating or completing the closure of a CCR unit.”

Initial dewatering and solids removal has started this year, and will be completed in 2019. The total expected cost of this project is forecasted to be approximately $3.7M. The 2019 portion of this project is forecasted to be $3.1M and is included in the $4.1M O&M total noted above. Per the CO, the removal of the CCR solids must begin within thirty days after ceasing flow to the FGD Blowdown pond and must be completed within eight months once the removal activities have been initiated. Once the CCR solids and pond liner are removed, DEF will complete closure of the FGD Blowdown ponds, as required under the CCR Rule. This includes breaching the dams and walls, and restoration of the grounds.

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

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

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

b) The activities are legally required to comply with a governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the Company's last test year upon which rates are based; and

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

Q. Are there any other CCR rule compliance activities and costs for which DEF expects to seek recovery in 2019?

A. DEF continues to evaluate the CCR rule to determine operating and cost impacts, and expects to incur costs in 2019 and beyond. In 2019, DEF will continue engineering for the design and permitting for a new lined landfill unit to dispose of CCRs as a corrective action for groundwater quality exceedances. However, the full extent of compliance activities, timing of these activities and associated costs cannot be determined until further analysis and assessment are complete, including CCR well data analysis and assessment of corrective measures for groundwater quality exceedances. 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. 20180007-EI

April 2, 2018

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 17 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), Mercury and Air Toxics Standards ("MATS") - Anclote Gas Conversion Project (Project 17.1), and Mercury & Air Toxics Standards (MATS) – CR 1&2 (Project 17.2) for the period January 2017 - December 2017.

Q. How do actual O&M expenditures for January 2017 - December 2017 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 $4,855,012 or 14% lower than projected. This variance is primarily attributable to $1.1M lower than expected CAIR Crystal River Project 7.4 – Base costs, and $3.8M 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 2017 - December 2017?

A: O&M costs for CAIR Crystal River Project – Base were $1,059,800 or 7% lower than projected. This was primarily due to approximately $0.7M in favorable labor costs and lower materials expense of approximately $0.4M.

Q. Please explain the variance between actual project expenditures and the actual/estimated projections for CAIR Crystal River Project – Energy for the period January 2017 - December 2017?

A. O&M costs for CAIR Crystal River Project - Energy were $3,782,500 or 20% lower than forecasted primarily due to variations in the reagent costs. Ammonia expense was approximately $1.0M favorable primarily due the urea markets declining since the beginning of 2017. Limestone and hydrated lime expense were approximately $1.6M and $0.5M favorable, respectively, primarily driven by lower than projected generation. Gypsum expense was approximately $0.8M favorable due to beneficial use sales pricing being higher than expected, and reduced production due to plant outages.

Q: Please explain the capital variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Conditions of Certification (Project 7.4q) for January 2017 - December 2017?

A: Capital costs for CAIR Crystal River Project – Conditions of Certification were $3,739,531 or15% higher than projected. Equipment procurement costs were ahead of schedule, which resulted in a variance of approximately $5.7M and Deep-Drill (Pilings) were approximately $2.9M higher than projected. This was partially offset by underground construction that was approximately $4.6M lower than forecasted due to planned 2017 work being re-scheduled to 2018.

Q. How did actual O&M expenditures for January 2017 - December 2017 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 $133,485 or 7% higher than projected. The O&M variance is primarily due to CR 1&2 higher than projected generation, resulting in additional maintenance of the MATS equipment.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>JEFFREY SWARTZ</u>

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20180007-EI

July 25, 2018

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. 20180007-EI?

A. Yes, I provided direct testimony on April 2, 2018.

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 2018 actual/estimated cost projections and original 2018 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 CR Program (Project 7.4) for the period January 2018 through December 2018?

A. O&M expenditures are expected to be $402,659 or 1% higher than originally projected primarily due to modifications of the hydrated lime system, which was partially offset by decreases in Limestone and Gypsum expenses.

Q. Please provide an update on the CAIR/CAMR CR Conditions of Certification Program (Project 7.4q).

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 20150007-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 expects this project to be placed in-service in or before February 2019.

DEF estimates 2018 capital costs of $45,000,558 for the CR4 & 5 FGD Blowdown wastewater project. These costs are for Mechanical-Electrical construction, including buildings and site work, remaining equipment procurement, remaining underground construction, start-up/commissioning, and construction oversight.

The 2018 estimate is approximately $3.4M or 8% higher than originally projected, and is primarily due to the grouting work and associated labor and equipment. The grouting was required due to extremely wet conditions exceeding the de-watering efforts at the site. There was an increased risk that further de-watering efforts, consisting of pumping water from the site, could result in the formation of sinkholes.

The total estimated FGD Blowdown wastewater project cost is $79.2M. This is an updated estimate from my September 1, 2016 testimony. The increase in the estimate is primarily driven by approximately $7.6M in additional work associated with surface conditions at the project site that were unknown at the time of the last estimate; these include sump grouting for foundation excavation work, deep foundation piling delays due to sinkholes and foundation work delays due to sinkholes. DEF also incurred additional equipment and engineering costs compared to the earlier projection of approximately $1.7M, as well as approximately $1.6M in weather-related work stoppages.

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. 20180007-EI

August 24, 2018

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. 20180007-EI?

A. Yes. I provided direct testimony on April 2, 2018 and July 25, 2018.

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 2019 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 2019 for air emission controls at Crystal River Units 4 and 5 (CR4&5) as part of the Integrated Clean Air Compliance Program (Project 7.4)?

A. DEF estimates O&M costs of approximately $35.8M 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 $9.0M based on current staffing levels, including labor for the CRN FGD Wastewater project.
- Contractor expenses are estimated at $5.8M for various services.

- Parts and materials are estimated at $2.6M.
- Other costs are estimated at $0.2M.
- CR5 outage costs are estimated at $1.1M.
- Reagent and bi-product costs (ammonia, limestone, hydrated lime, caustic, dibasic acid and net gypsum sales/disposal) are estimated to total $17.1M.

Q. What capital expenditures does DEF expect to incur in 2019 for the implementation of the Integrated Clean Air Compliance Program (Project 7.4q)?

A. DEF estimates 2019 capital expenditures of approximately $3.9M for the CR 4&5 FGD Blowdown wastewater project. This will complete the project, which is expected to go in-service in or before February 2019.

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. What 2018 O&M costs does DEF expect to incur for the CR 4&5 FGD Blowdown Wastewater Treatment project (Project 7.4q).

A. The 2019 O&M cost for the FGD WWT are projected to be approximately $2.9M. This includes costs associated with the initial training of the new employees as the plant becomes operational during the first quarter of 2019. The positions consist of Supervisors, Electricians, Control Technicians, and a Certified Welder/Mechanic. These are reflected in Exhibit__(JS-1).

Consistent with DEF's Response to question 14 in Staff's First Set of Interrogatories in Docket 20170007-EI, DEF is projecting ten new positions at the FGD WWT Plant. FGD WWT Operators will be required 24 hours per day to operate the system, provide basic maintenance, and conduct analytics required to operate the system.

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 61 employees that report to the Crystal River North Station Manager and 1 employee who reports to the Director-Florida Fossil-Hydro-Finance. There are 8 managers and 53 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 2019 for the MATS Program – CR1&2 (Project 17.2)?

A. DEF estimates O&M costs of approximately $60k for MATS CR 1&2. The CR 1&2 plants are being retired in 2018, and some final shutdown costs are expected in 2019.

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. 20180007-EI

April 2, 2018

Q. Please state your name and business address.

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

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") 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 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 FPSC-approved programs under my responsibility. These programs include the T&D 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) (Projects 6 & 6a), 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") Units 4&5 (Project 17) for the period January 2017 through December 2017.

Q. How did actual O&M expenditures for January 2017 - December 2017 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 $321,005 or 27% lower than projected. The Transmission portion (Project 1) is $212k or 37% lower than forecasted primarily due to repairs needed at Central Florida, East Clearwater, Holder, and Tarpon Springs substations which must be completed before remediation can continue. These repair schedules are currently projected for 2018 and 2019. The Distribution portion (Project 1a) is $109k or 17% lower than forecasted due to the re-scheduling of breaker house removal at Kenneth Substation to first quarter 2018. Removal of the building must be completed before remediation can begin again. Remediation at Wekiva substation resumed in December 2017; however, due to an ongoing circuit breaker replacement project, remediation activities were suspended until the breaker project is complete.

Q. How did actual O&M expenditures for January 2017 - December 2017 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 $31,048 or 86% lower than projected. There were two sampling events performed at the 7100 Sunset Way, St. Petersburg Beach location, and no remediation was required. Monitoring will continue.

Q. How did actual O&M expenditures for January 2017 - December 2017 compare with DEF's actual/estimated projections for the PIM Project (Project 3)?

A. The PIM O&M variance is $10,208 or 100% lower than projected. This variance is due to a contractor refund.

Q. How did actual O&M expenditures for January 2017 - December 2017 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) (Projects 6 & 6a) O&M variance is $102,194 or 45% higher than projected, driven primarily by Cooling Water Intake 316(b) – Base (Project 6), which had a $109k or 57% higher than projected variance primarily due to study costs related to Crystal River North ("CRN") evaluation of compliance options. This was slightly offset by a $7k favorable O&M variance for 316(b) – Intermediate (Project 6a).

Q. How did actual Capital expenditures for January 2017 - December 2017 compare with DEF's 2017 estimated expenditures for the Cooling Water Intake - 316(b) Project (Project 6)?

A. The Cooling Water Intake – 316(b) (Project 6) Capital variance is $1,036,693 or 61% lower than projected, driven primarily by planned 2017 work being re-scheduled to 2018.

Q. How did actual O&M expenditures for January 2017 - December 2017 compare with DEF's actual/estimated projections for the Arsenic Groundwater Standard Project (Project 8)?

A. The Arsenic Groundwater Monitoring variance is $17,504 or 15% lower than projected primarily due to a change in the sampling schedule.

Q. How did actual Capital expenditures for January 2017 - December 2017 compare with DEF's actual/estimated projections for the Effluent Limitations Guideline Project (Project 15.1)?

A. The ELG Capital variance is $16,145 or 15% lower than projected. This project is currently on hold pending issuance of the NPDES permit renewal for CR 4 & 5 following the September 18, 2017 EPA final rule postponing the compliance deadlines of FGD wastewater and bottom ash transport water for two (2) years.

Q. How did actual O&M expenditures for January 2017 - December 2017 compare with DEF's actual/estimated projections for the National Pollutant Discharge Elimination System ("NPDES") Project (Project 16)?

A. The NPDES Project O&M variance is $43,760 or 62% lower than forecasted, and is primarily attributed to removal of the Whole Effluent Toxicity ("WET") testing requirement at the Suwannee Station.

Q. How did actual O&M expenditures for January 2017 - December 2017 compare with DEF's actual/estimated projections for the MATS – CR 4&5 Project (Project 17)?

A. The MATS – CR 4&5 O&M variance is $464,030 or 78% lower than forecasted, primarily due to lower than expected purchases of mercury re-emissions chemical in 2017. The chemical is used during generator start-up to control mercury emissions, and kept on-site. No additional stock was purchased during the year.

Q. In Order No. PSC-2010-0683-FOF-EI issued in Docket No. 20100007-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.

Q. What is the status of the Cross State Air Pollution Rule ("CSAPR")?

A. 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. On September 7, 2016, EPA finalized its CSAPR Update rule, lowering the current CSAPR state ozone season NOx emission budgets for 22 Eastern states. EPA eliminated Florida, South Carolina, and North Carolina from the CSAPR ozone season program based on modeling which shows that NOx emissions from these states do not significantly contribute to ozone nonattainment in any downwind state. Duke Energy sources in Florida are no longer subject to any CSAPR NOx emission limitations as of the beginning of 2017.

Q. What is the status of the ELG (Project 15.1)?

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 were to have been incorporated into affected stations' NPDES permits with a compliance timeframe between November 1, 2018 and December 31, 2023; however, on September 18, 2017, EPA issued a final rule postponing the compliance deadlines of FGD wastewater and bottom ash transport water for two years. 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 expanded 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 Sixth Circuit 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 was contested, and on January 13, 2017 the U.S. Supreme Court decided to review the jurisdictional question. Oral arguments in the U.S. Supreme Court case were conducted in October 2017. On January 22, 2018, the U.S. Supreme Court issued its decision stating federal district courts, instead of federal appellate courts, have jurisdiction over challenges to the rule defining waters of the United States Consistent with the U.S. Supreme Court decision, the U.S. Court of Appeals for the Sixth Circuit lifted its nationwide stay on February 28, 2018. The stay issued by the North Dakota District Court remains in effect, but only within the thirteen states within the North Dakota District. On February 28, 2017, President Trump signed an executive order laying out a new policy direction for how "Waters of the United States" should be defined and directing EPA and the Corps to initiate a rulemaking to either rescind or revise the 2015 Clean Water Rule developed by the Obama administration. Subsequently, the EPA Administrator signed a pre-publication notice reflecting the intent to move forward with rulemaking in response to this directive. In addition, the executive order seeks to have the Department of

Justice determine the path forward on the Clean Water Rule litigation in light of the new policy direction.

On January 31, 2018, the EPA and Corps announced a final rule adding an applicability date to the 2015 rule defining "waters of the United States," thereby deferring implementation of the 2015 WOTUS Rule until early 2020. This rule has no immediate impact to Duke Energy, and the agencies will continue to apply the pre-existing WOTUS definition in place prior to the 2015 rule until 2020.

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. 20180007-EI

July 25, 2018

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. 20180007-EI?

A. Yes, I provided direct testimony on April 2, 2018.

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 2018 actual/estimated cost projections and original 2018 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 2017 through December 2017.

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 2018 through December 2018.

A. O&M expenditures for the substation system program are estimated to be $173,511 or 25% higher than originally projected. Project 1, Transmission Substation Remediation, is forecasted to be $87k, or 22% higher than originally projected. The variance is primarily due to higher than anticipated remediation costs at Central Florida Substation than initially projected. Project 1a, Distribution Substation Remediation, is forecasted to be $86k, or 30% higher than originally projected. The variance is primarily attributable to remediation work at the Kenneth City Substation coming in higher than originally estimated due to more contaminated soil excavated once the breaker/control house was removed. The work at this site is complete and the remediation report is being prepared to be sent to the Florida Department of Environmental Protection ("FDEP") for review.

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 2018 through December 2018.

A. O&M expenditures for the distribution system program are estimated to be $7,000 or 47% lower than originally forecasted. DEF has been conducting groundwater quality monitoring at the 7100 Sunset Way, St. Petersburg Beach location. All events have been showing as clean, so no remediation has yet been required for 2018. This is the final location being remediated and monitored under this program.

Q. Please explain the variance between actual/estimated Capital project expenditures and original projections for Phase II Cooling Water Intake 316(b) (Project 6) for the period January 2018 through December 2018.

A. Capital expenditures for Phase II Cooling Water Intake 316(b) are expected to be $1,070,592 or 63% lower than forecasted. This is primarily due to delays associated with ongoing discussions with the FDEP and Florida Fish and Wildlife Conservation Commission, and also construction work at the Citrus Combined Cycle project, which provides the source water for this project. This is not expected to impact the 2020 in-service date or the original estimate.

Q. Please explain the variance between actual/estimated project expenditures and original projections for the Arsenic Groundwater Standard (Project 8) for the period January 2018 through December 2018.

A. O&M expenditures for the Arsenic Groundwater Standard are expected to be $20,228 or 13% higher than forecasted. This is primarily due to the need to perform additional hydrological evaluation of monitoring well #32 to determine cause of elevated arsenic levels.

Q. Please explain the variance between actual/estimated project expenditures and original projections for Sea Turtle – Coastal Street Lighting (Project 9) for the period January 2018 through December 2018.

A. O&M expenditures for Sea Turtle – Coastal Street Lighting are expected to be $250 or 71% higher than forecasted. Capital is expected to be $200 or 50% higher than forecasted. Sea turtle season started May 1, 2018, and recently DEF was notified of possible street light issues in Clearwater, FL which may require amber lens installations and/or new lighting.

Q. Please explain the variance between actual/estimated project expenditures and original projections for the Effluent Limitation Guidelines CRN (Project 15.1) for the period January 2018 through December 2018.

A. Capital expenditures are forecasted to be $911,372 or 100% higher than originally forecasted. O&M expenditures are forecasted to be $40k. No capital or O&M expenditures were originally projected for 2018, as this project was placed on hold due to the September 18, 2017 EPA issuance of a final rule that deferred the compliance deadline of Flue Gas Desulfurization ("FGD") wastewater and bottom ash transport water ("BATW") for two years, as soon as November 1, 2020, but no later than December 31, 2023.

Q. Please explain the variance between actual/estimated project expenditures and original projections for MATS CR4&5 (Project 17) for the period January 2018 through December 2018.

A. O&M expenditures for MATS CR 4&5 are expected to be $139,539 or 23% lower than forecasted. This is primarily due to lower than planned mercury re-emission chemical usage, and burner inspections that were less than originally projected.

Q. Please provide an update on Effluent Limitation Guidelines ("ELG") and DEF's Effluent Limitation Guidelines Program (Project 15.1).

A. On November 23, 2015, 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. On September 18, 2017, EPA issued a final rule postponing the compliance deadline of FGD wastewater and bottom ash transport water for two years, between November 1, 2020 and December 31, 2023. ELG requirements for BATW are presently under administrative review by EPA, and final guidance is expected by the end of 2018. DEF is working with FDEP to address these requirements in the Crystal River Units 4 and 5 NPDES permit that is now in the renewal process.

DEF's compliance plan will be implemented in a two-phase approach to eliminate discharge of BATW to surface waters by June 30, 2019. The first phase of the plan will address requirements that are common between the renewed NPDES permit and the ELG: directing blowdown of BATW for reuse in the Crystal River Units 4 and 5 FGD scrubber; directing blowdown of BATW to the permitting percolation pond as a secondary discharge location; and, replacing wet pump seals with dry pump seals to minimize the amount of water introduced into the bottom ash handling system. These activities are consistent with the ELG project scope of work approved by the Commission in Order No. PSC-2013-0606-FOF-EI in Docket 20130007.

Plans for the second phase of the ELG compliance plan will be finalized and implemented once the EPA issues its final guidance. The second phase of the plan will include longer-term compliance strategies to allow for normal maintenance activities and water balance management. The specific schedule for completing this work will be dependent upon the final guidance issued by EPA, but is currently expected to be completed by December 31, 2023.

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 continues.

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. Both the Anclote and Bartow stations are within this schedule and the required information is being prepared for submittal with the renewal applications due July 2020 and August 2020, respectively. Certain 316(b) requirements are being evaluated for Crystal River Units 4 and 5 as part of the current permit renewal.

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.

Q. Please provide an update on Carbon Regulations.

A. For existing Units, 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 established state-specific emission goals; for Florida, the goals included a phased approach beginning in 2022, ending with a rate goal of 919 lb. CO_2/MWh annual average for the period 2030 and beyond. Alternatively, the state could 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 was challenged by 27 states and a number of industry groups, with oral arguments held before the D.C. Circuit Court of Appeals on September 27, 2016. In addition, on February 9, 2016, the U.S. Supreme Court placed a stay on the CPP until all litigation is completed.

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 and is currently on appeal to the D.C. Circuit Court of Appeals.

On March 28, 2017, President Trump signed an Executive Order ("EO") entitled "Promoting Energy Independence and Economic Growth." The EO directs federal agencies to "immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources." The EO specifically directs the EPA to review the following rules and determine whether to suspend, revise, or rescind those rules:

- The final CO2 emission standards for existing power plants (CPP);
- The final CO2 emission standards for new power plants (CO2 NSPS);
- The proposed Federal Plan and Model Trading Rules that accompanied the CPP.

In response to the EO, the Department of Justice filed motions with the D.C. Circuit Court to stay the litigation of both the CPP and the CO2 NSPS rules while each is reviewed by EPA. As a result, the D.C. Circuit has granted a number of 60-day extensions holding the CPP litigation in abeyance. The most recent extension was issued on June 26, 2018. Neither the EO nor the abeyance change the current status of the CPP which is under a legal hold by the U.S. Supreme Court. With regard to the CO2 NSPS, that rule will remain in effect pending the outcome of EPA's review.

On June 29, 2017, the U.S. Department of Justice provided a status report on EPA's regulatory review of the CPP to the D.C. Circuit. In the report, DOJ requested that the litigation remain in abeyance pending the conclusion of

EPA's anticipated rulemaking. Based on the most recent extension by the court, the litigation is expected to remain in abeyance or be dismissed by the court and remanded back to EPA.

DEF does not expect to incur ECRC costs in 2018 related to carbon regulations.

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. On March 1, 2018 EPA proposed amendments to the April 17, 2015 final rule. The proposal addresses four provisions in the final rule that were remanded back to EPA on June 14, 2016 by the U.S. Court of Appeals for the D.C. Circuit. DEF's planned 2018 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 D.C. Circuit Court challenging EPA's findings. These legal actions are currently being held in abeyance pending further EPA review of the rule. 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. FDEP modeled the area surrounding the Crystal River facility and determined that future operation will not cause a nonattainment issue. This finding was provided to EPA on January 13, 2017, as part of the FDEP's Data Requirements Rule package submittal. On July 3, 2017, EPA published a final rule approving attainment plans for the two non-attainment areas outside of DEF's service territory. In December 2017, EPA issued a final ruling for the area around the DEF's Crystal River station designating that area as unclassifiable, pending final certification of complete 2017 monitoring data. Based on the final 2017 data, EPA changed the designation to attainment in early 2018. Currently the entire DEF service area is in compliance with the SO_2 standard.

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 was contested, and on January 13, 2017 the U.S. Supreme Court decided to review the jurisdictional question. Oral arguments in the U.S. Supreme Court were conducted in October 2017. On January 22, 2018 the U.S. Supreme Court issued its decision stating federal courts, rather than federal appellate courts, have jurisdiction over challenges to the rule defining waters of the United States. Consistent with the U.S. Supreme Court decision, the U.S. Court of Appeals for the Sixth Circuit lifted its nationwide stay on February 28, 2018. The stay issued by the North Dakota District Court remains in effect, but only within the thirteen states within the North Dakota District. On June 8, 2018, the Southern District Georgia Court entered a Preliminary Injunction enjoining implementation of the WOTUS rule in eleven states including Florida.

On June 27, 2017, the EPA and the Corps published a proposed rule to repeal the 2015 WOTUS rule and re-codify the definition of WOTUS which is currently in place. On January 31, 2018 the EPA and Corps announced a final rule adding an applicability date to the 2015 rule, thereby deferring implementation to early 2020. This rule has no immediate impact to Duke Energy, and the agencies will continue to apply the pre-existing WOTUS definition that was in place prior to 2015 rule until 2020.

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. 20180007-EI

August 24, 2018

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. 20180007-EI?

A. Yes. I provided direct testimony on April 2, 2018 and July 25, 2018.

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 2019 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 CRN (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 2019 for the Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a)?

A. DEF estimates approximately $409k of O&M costs at 7 sites for the Substation Environmental Investigation, Remediation and Pollution Prevention Program. The Distribution portion of this program is expected to be complete in 2018, all remaining sites are Transmission only.

Q. What costs does DEF expect to incur in 2019 for the Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2)?

A. DEF is projecting approximately $8k in O&M for the Distribution System Investigation, Remediation, and Pollution Prevention Program (Project 2) for groundwater monitoring at the 7100 Sunset Way, St. Petersburg Beach location.

Q. What costs does DEF expect to incur in 2019 for the PIM Program (Project 3)?

A. The PIM Program assets retired September 2016 and June 2017. As approved in Order Nos. PSC-2016-0535-FOF-EI and PSC 2018-0014-FOF-EI, DEF is amortizing the net book value of the PIM Program assets over three years. DEF is projecting approximately $411k of amortization in 2019, and all assets will be fully amortized as of September 2019.

Q. What costs does DEF expect to incur in 2019 for the Aboveground Storage Tank ("AST") Program (Project 4)?

A. DEF does not expect to incur any capital expenditures or O&M costs in 2019.

Q. What costs does DEF expect to incur in 2017 for the Phase II Cooling Water Intake Program (Project 6)?

A. Site specific strategic plans, studies, and implementation plans are under development to ensure compliance with all applicable requirements of the rule. DEF expects to incur $298k in O&M costs in 2019, which includes 122.21(r) reports for Anclote and Bartow stations in order to assess 316(b) compliance, and programmatic costs for all stations with NPDES permits. DEF will submit study results to FDEP for Anclote July 2020 and Bartow August 2020.

DEF expects 2019 capital expenditures to be approximately $4.4 million for the Crystal River North 316(b) compliance project.

Q. What costs does DEF expect to incur in 2019 for the CAIR/CAMR Program (Project 7.2)?

A. DEF does not expect to incur any capital expenditures or O&M costs in 2019.

Q. What costs does DEF expect to incur in 2019 for the BART Program (Project 7.5)?

A. DEF does not expect to incur any costs in 2019.

Q. What costs does DEF expect to incur in 2019 for the Arsenic Groundwater Standard Program (Project 8)?

A. DEF estimates approximately $150k in O&M costs for the Arsenic Groundwater Standard Program, primarily to perform hydrological evaluation of Monitoring

Well #32 to determine potential sources of elevated arsenic levels and support site assessment evaluation of the former north ash pond. 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.

Q. What costs does DEF expect to incur in 2019 for the Sea Turtle – Coastal Street Lighting Program (Project 9)?

A. DEF estimates $350 and $400 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 2019 for the Underground Storage Tanks ("UST") Program (Project 10)?

A. DEF does not expect to incur any capital expenditures or O&M costs in 2019.

Q. What costs does DEF expect to incur in 2019 for the Modular Cooling Tower (Project 11)?

A. DEF does not expect to incur any costs in 2019.

Q. What costs does DEF expect to incur in 2019 for the Thermal Discharge Permanent Cooling Tower (Project 11.1)?

A. DEF does not expect to incur any costs in 2019.

Q. What costs does DEF expect to incur in 2019 for the Greenhouse Gas Inventory and Reporting Program (Project 12)?

A. DEF does not expect to incur any costs in 2019.

Q. What costs does DEF expect to incur in 2019 for the Mercury TMDL Program (Project 13)?

A. DEF does not expect to incur any costs in 2019.

Q. What costs does DEF expect to incur in 2019 in for the HAPs ICR Program (Project No. 14)?

A. DEF does not expect to incur any costs in 2019.

Q. What costs does DEF expect to incur in 2019 for the Effluent Limitation Guidelines ICR Program (Project No. 15)?

A. DEF does not expect to incur any costs in 2019.

Q. What costs does DEF expect to incur in 2019 for the Effluent Limitation Guidelines CRN Program (Project No. 15.1)?

A. DEF does not expect to incur any 2019 capital or O&M costs for the ELG Crystal River North project.

Q. What costs does DEF expect to incur in 2019 for the NPDES Program (Project No. 16)?

A. DEF estimates approximately $26k of O&M costs for Whole Effluent Toxicity ("WET") testing as required at DEF stations with NPDES permits.

Q. What O&M costs does DEF expect to incur in 2019 for the MATS Program – CR 4&5 (Project No. 17)?

A. DEF estimates O&M costs of approximately $598k for CR 4&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 2019 for the MATS Program – CR 4&5 (Project No. 17)?

A. DEF does not expect capital expenditures in 2019.

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, and during my tenure I assumed positions of increasing responsibility. I have over 20 years of electric utility experience, including load forecasting, managing cost recovery clauses, project management, and rate setting activities for cost recovery clauses and 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 2017 through December 2017 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 2017 through December 2017 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 26, 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 2017 through December 2017?

A. The final true-up amount for the Environmental Clause for the period January 2017 through December 2017 is an over-recovery of $1,498,666. The actual environmental cost over-recovery, including interest, is $8,258,090 for the period January 2017 through December 2017, as identified in Form 42-1A. This amount, less the $6,759,424 over-recovery approved in Commission Order No. PSC-2018-0014-FOF-EI, issued January 5, 2018, in Docket No. 20180007-EI, results in a final over-recovery of $1,498,666, 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 2019 through December 2019.

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. How do actual expenditures for the January 2017 through December 2017 period compare with Tampa Electric's actual/estimated projections as presented in previous testimony and exhibits?

A. As shown on Form 42-4A, total costs for O&M activities are $1,595,678, or 7.0 percent less than the actual/estimated projection costs. Form 42-6A shows the total capital investment costs are $21,547, or less than 0.1 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 or if additional work is needed, then the company will have a variance when actual amounts expended are compared to the projection. When inspections indicate that work is not needed now, that maintenance expense will be incurred in a future period when warranted by the condition of the unit.

- **Big Bend Unit 3 Flue Gas Desulfurization Integration:** The Big Bend Unit 3 Flue Gas Desulfurization Integration project variance is $192,685 or 3.8 percent greater than projected. The variance is due to greater than projected maintenance expenses related to ductwork and cooling towers.

- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is $4,616 or 106.4 percent less than projected. The variance is due to less cogeneration purchases than projected and the application of a lower SO_2 emissions allowance rate than projected.

- **Big Bend Units 1 and 2 Flue Gas Desulfurization ("FGD"):** The Big Bend Units 1 and 2 FGD project variance is $1,373,172 or 30.3 percent greater than projected. The variance is due to greater than expected maintenance costs for structural steel repairs to ductwork and towers, as well as greater than projected limestone consumption.

- **Big Bend NO_x Emission Reduction:** The Big Bend NO_x Emission Reduction project variance is $97,791 or 23.5 percent greater than projected. The variance is due to greater than expected maintenance costs associated with the repair of air dampers.

- **Polk NO_x Emission Reduction:** The Polk NO_x Emission Reduction project variance is a credit of $2,758, or 11.4 percent less than projected. This variance is due to the Polk gasifier running less than projected because of outages and hurricane related start-up delays.

- **Big Bend Unit 4 Separated Overfire Air ("SOFA"):** The Big Bend Unit 4 SOFA project variance is $6,000, or 100.0 percent less than projected. This variance occurred because less work was needed than projected.

- **Big Bend Unit 2 Pre-Selective Catalytic Reduction ("SCR"):** The Big Bend Unit 2 Pre-SCR project variance is $440,878, or 2,028.6 percent greater than projected. The variance is associated with work performed on secondary air dampers not anticipated in the projection.

- **Bid Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is $11,167, or 148.1 percent greater than projected. The variance was driven by unanticipated costs to replace bearings on secondary air dampers.

- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) project variance is $60,794, or 13.3 percent greater than projected. This variance is due to the netting of higher than anticipated expenditures for the Bayside Station external peer review process and lower than anticipated expenditures for Big Bend Station.

The external peer review process is a requirement under Rule 316(b), in accordance with Environmental Protection Agency ("EPA") guidance, for studies to comply with §122.21(r)(10) through (r)(12). The external peer review process began in 2016 and was completed for Bayside Station, with a final Rule 316(b) report submitted to the FDEP in February 2018. Bayside Station peer review expenses were greater than expected because some sections of the draft report required more work than initially anticipated to address peer reviewer comments. Ongoing negotiations with Florida Department of Environmental Protection ("FDEP") regarding renewal of the Big Bend Station National Pollutant Discharge Elimination System ("NPDES") permit have had an impact on the compliance schedule. As a result, some expected expenses will be deferred to future periods.

- **Arsenic Groundwater Study Program:** The Arsenic Groundwater project variance is $22,572, or 39.4 percent more than projected. This variance is primarily due to greater than expected costs for removal and abandonment of wells and injection equipment at Bayside Station, as required by the FDEP Site Rehabilitation Completion Order. Costs for Big Bend Station arsenic program monitoring and testing were also higher than expected during 2017.

- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is $344,899, or 35.5 percent less than projected. Less maintenance activity was required than projected during 2017. In addition, the SCR ran less than expected, so the cost for consumables was less than projected.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is $148,145, or 12.1 percent greater than projected. This variance is due to increased maintenance costs associated with clearing ash build-up. In addition, the SCR ran more than expected, so the cost for consumables was greater than projected.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is $62,081, or 7.4 percent less than projected. The costs associated with this project are less than projected because less maintenance work was needed than projected.

- **Mercury Air Toxics Standards:** The Mercury Air Toxics Standards ("MATS") project variance is $54,696, or 79.9 percent less than projected. The projected costs included O&M costs for mercury Continuous Emission Monitors ("CEM"). Because Polk Station and Big Bend Station achieved Low Emitting Electric Generating Unit ("EGU") status in 2017, mercury CEM were not required, and costs were less than projected.

- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility project variance is $273,888, or 11.9 percent less than projected due to reduced storage yard activity due to lower volume of gypsum produced.

- **Big Bend Coal Combustion Residuals Rule:** The Big Bend Coal Combustion Residuals ("CCR") Rule project variance is $2,947,341, or 81.3 percent less than projected. This variance is due to the start date for CCR disposal, approved as part of the company's second phase of CCR Rule compliance, occurring later than projected. As a result, the costs will be deferred to a future period.

- **Big Bend Effluent Limitations Guidelines:** The Big Bend Effluent Limitations Guidelines ("ELG") project variance is $177,848, or 90.3 percent less than projected. This variance is caused by delays in determining final ELG compliance dates and the issuance of the NPDES permit identifying compliance activities and timeline.

Capital Investment Project Variances

- **Big Bend Coal Combustion Residuals Rule:** The Big Bend CCR Rule capital project variance is $8,365, or 14.0 percent less than projected. This is primarily due to projected costs to engineer the Economizer Ash & Pyrites Ponds Closure as part of the company's second phase of CCR Rule that were expected during 2017; however, the work was postponed until 2018. The engineering work was not required prior to beginning the CCR disposal efforts.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180007-EI
FILED: 07/25/2018
REVISED: 07/27/2018

BEFORE THE FLORIDA 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. Have you previously filed testimony in Docket No. 20180007-EI?

A. Yes, I submitted direct testimony on April 2, 2018.

Q. Has your job description, education, or professional experience changed since then?

A. No.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2018 through December 2018 actual/estimated true-up amount to be refunded or recovered through the Environmental Cost Recovery Clause ("ECRC") during the period January 2019 through December 2019. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2018, 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 2019 through December 2019.

Q. Have you prepared exhibits that show the recoverable environmental costs for the actual/estimated period of January 2018 through December 2018?

A. Yes, I prepared two exhibits. 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 2019 through December 2019. Exhibit No. PAR-3, which contains seven documents, includes selected schedules without the costs of Tampa Electric's two new proposed ECRC projects for compliance with the Effluent Limitations Guidelines ("ELG") Rule and Section 316(b) of the Clean Water Act.

Q. What has Tampa Electric calculated as the actual/estimated true-up for the current period to be applied.

A. The actual/estimated true-up applicable for the current period, January 2018 through December 2018, is an over-recovery of $13,472,483. A detailed calculation supporting the true-up amount 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 2018 ECRC factors?

A. Yes, Tampa Electric included costs associated with the company's compliance with Section 316(b) of the Clean Water Act. The company's petition for approval to recover such costs through the ECRC was filed on April 26, 2018. In addition, new costs for compliance with the ELG Rule are included. The company's petition for approval to recover such costs through the ECRC was filed on May 9, 2018. The respective petitions explain the need for the projects and the regulations requiring those activities. The testimony of Tampa Electric witness Paul L. Carpinone submitted concurrently in this docket also supports these projects.

Q. What depreciation rates were utilized for the capital projects contained in the 2018 actual/estimated true-up?

A. Tampa Electric utilized the depreciation rates approved in Order No. PSC-2012-0175-PAA-EI, issued on April 3, 2012, in Docket No. 20110131-EI, with two exceptions. For the Big Bend Fuel Oil Tank No. 1 Upgrade and Big Bend Fuel Oil Tank No. 2 Upgrade projects, the company has utilized depreciation rates calculated to recover the remaining net investment balances of these now-retired assets from July 2018 through December 2021, which represents a five-year period from the date of their retirement on December 31, 2016. Tampa Electric requests approval for this treatment as it is consistent with Commission-approved treatment for other assets retired before the end of their projected depreciable life over a five-year period from the date of retirement. For example, the accelerated recovery of the remaining net investment balance of the Gannon Ignition Oil Tank project over a five-year period was authorized by Commission Order No. PSC-2000-2391-FOF-EI, issued December 13, 2000 in Docket No. 20000007-EI.

Q. Why were the assets of the Big Bend Fuel Oil Tank No. 1 Upgrade and Big Bend Fuel Oil Tank No. 2 Upgrade projects retired earlier than expected?

A. The assets were retired December 31, 2016 after an analysis of the expenses to maintain them and consideration of the low utilization of oil at the station after the Big Bend igniters on Units 1 through 4 were converted to natural gas operation. In 2016, the maintenance cost to bring the 4.5 million-gallon tank system to current standards was estimated at $1.5 million. Annual monitoring and reporting costs were approximately $50,000 to $75,000. In light of these substantial costs and the fact that oil use at the station was greatly reduced after the igniters conversion in 2015, so that a large amount of oil storage was no longer needed, Tampa Electric retired the assets. With the retirement, Tampa Electric was no longer required to fill the tank with now-unneeded amounts of No. 2 fuel oil at the start of each hurricane season to prevent the tank from floating in the event of storm related flooding. Finally, retiring the tank avoided the continued environmental costs and risks of managing a tank of this size in proximity to the waters of the State.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2018 through December 2018?

A. Tampa Electric's revenue requirement rate of return for January 2018 through December 2018 is calculated based on the capital structure, components and current period cost rates as approved in Order No. PSC-2012-0425-PAA-EU, issued on August 16, 2012 in Docket No. 20120007-EI. The calculation of the revenue requirement rate of return is shown on Form 42-9E.

Q. Has Tampa Electric adjusted the revenue requirements of its ECRC capital projects to reflect the lower tax rate of 21 percent in the Tax Cuts and Jobs Act of 2017 ("TCJA")?

A. Yes, the company updated the tax multiplier utilized in the determination of the equity component of the revenue requirement rate of return, shown on Form 42-9E, Document

No. 9 of my Exhibit No. PAR-2.

Q. Did the company apply the lower tax rate in the calculation of revenue requirements for its ECRC capital projects for the period January 2018 through December 2018?

A. Yes. Tampa Electric calculated the new tax multiplier and revised rate of return in early 2018 and began applying the rate to the monthly ECRC net investment balances in May 2018. The company calculated an adjustment to reflect revenue requirements with the lower tax rate for the months of January 2018 through April 2018 and booked the adjustment, including interest, in May 2018. This tax adjustment effectively identified and recorded the difference in the amount of allowed cost recovery for environmental projects due to the lower tax rate as an over-recovery for the first four months of 2018 that will be considered as part of the company's projected overall over- or under-recovery for the year.

Form 42-8E, which is included as Document No. 8 of Exhibit No. PAR-2, shows the calculation of the adjusted monthly revenue requirements for capital projects using the lower tax rate and revised rate of return for the January through December 2018 period.

Q. Will the company account for the flowback of excess accumulated deferred income taxes associated with environmental projects in this docket or as part of Docket No. 20180045-EI, which addresses the overall impact of the TCJA on the company?

A. The flowback of excess accumulated deferred income taxes associated with environmental projects recovered through the environmental cost recovery clause is being addressed in Docket No. 20180045-EI and does not need to be considered in this docket.

Q. How did the actual/estimated project expenditures for the January 2018 through December 2018 period compare with the company's original projections?

A. As shown on Form 42-4E, total O&M costs are expected to be $9,400,732 less than the amount that was originally projected. The total capital expenditures itemized on Form 42-6E, are expected to be $4,523,890 less than originally projected. Significant variances for O&M costs and capital project amounts are explained 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 work. The need varies according to the actual usage and associated "wear and tear" on the units. If inspection indicates that the maintenance is not yet needed or if additional work is needed, then the company will have a variance compared to the projection. When inspections indicate that work is not needed now, that maintenance expense will be incurred in a future period when warranted by the condition of the unit.

- **Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration:** The Bend Unit 3 FGD Integration Project variance is estimated to be $2,529,108 or 57.2 percent less than projected due to greater operation on natural gas, compared to the original projection. This reduces the expected need for consumables and maintenance.

- **Big Bend Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance is estimated to be $1,629,196 or 74.1 percent less than projected. The variance is due to lower costs for consumables and maintenance than expected as the units burned natural gas.

- **Big Bend PM Minimization & Monitoring:** The Big Bend PM Minimization & Monitoring Project variance is estimated to be $204,721 or 33.5 percent lower than projected. This variance is due to less maintenance being required than expected, after inspection.

- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance is $60,263 or 43.4 percent less than projected. This variance is due to the operation of Big Bend Units 1 & 2 on natural gas.

- **Bayside Selective Catalytic Reduction ("SCR") Consumables:** The Bayside SCR Consumables project variance is estimated to be $92,779 or 45.5 percent less than projected. This variance is due to less total run time estimated for Bayside Station units, compared to the original projection, resulting in less ammonia consumption.

- **Clean Water Act Section 316(b) Phase II Study Program:** The Clean Water Act Section 316(b) Phase II Study Program project variance is $246,842 or 76.9 percent less than projected. The National Pollutant Discharge

Elimination System ("NPDES") permit renewal for Big Bend Station has not yet been finalized. The variance is related to uncertainty regarding the timing of the final requirements and reporting that must be submitted once the permit is finalized.

- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is $1,147,483 or 76.6 percent less than originally projected. This variance is due to operation of the unit on natural gas, which reduced the unit's need for consumables and maintenance work, compared to the original projection.

- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is $1,268,864 or 77.8 percent less than originally projected. This variance is due to operation of the unit on natural gas, which reduced the use of consumables and need for maintenance work, compared to the original projection.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is $141,390 or 8.3 percent less than projected. This variance is due to greater operation on natural gas, compared to the original projection.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is $410,017 or 38.6 percent less than projected. This variance is due to less total run time estimated when compared to the original projection.

- **Mercury Air Toxics Standards:** The Mercury Air Toxics Standards project variance is $206,622 or 89.4 percent less than projected. Both Polk and Big Bend Power Stations achieved Low Emitting Electric Generating Unit status in 2017. As a result, monitoring is not required at this time, only periodic testing, and the costs were lower than originally projected.

- **Big Bend ELG Rule Study:** The Big Bend ELG Study project variance is $54,007 greater than projected. This variance is due to a delay in completing the study, compared to the original projection. The study has now been completed.

- **CCR Rule – Phase II:** The Big Bend Coal Combustion Residual ("CCR") Rule Phase II project variance is $1,367,762 or 22.3 percent less than projected. This variance is due to timing differences in the project schedule when compared to the original projection. Dewatering activities, which must occur before the CCR disposal, have occurred more slowly than originally projected. The project expenditures are still needed and will be incurred in the future.

Capital Project Variances

There were significant capital variances for the projects listed below, each of which was due to the TCJA tax rate change from 35 percent to 21 percent.

- Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration
- Big Bend Units 1 & 2 FGD
- BIG Bend FGD Optimization and Utilization
- Big Bend NOx Emissions Reduction
- Big Bend Particulate Matter Minimization
- Big Bend Unit 1 SCR
- Big Bend Unit 2 SCR
- Big Bend Unit 3 SCR
- Big Bend Unit 4 SCR
- Big Bend FGD System Reliability
- Mercury Air Toxics Standards
- Big Bend Gypsum Storage Facility
- CCR Rule – Phase I

As I stated earlier, Tampa Electric updated the tax multiplier utilized in the determination of the equity component of the revenue requirement rate of return and applied the lower tax rate in the calculation of revenue requirements for the ECRC capital projects for the period January 2018 through December 2018.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180007-EI
FILED: 08/24/2018

BEFORE THE FLORIDA 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. Have you previously filed testimony in Docket No. 20180007-EI?

A. Yes, I submitted direct testimony on April 2, 2018 and July 25, 2018.

Q. Has your job description, education, or professional experience changed since then?

A. No, it has not.

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 Environmental Cost Recovery Clause ("ECRC") factors for the period of January 2019 through December 2019. 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 & maintenance ("O&M") costs associated with environmental compliance activities for the year 2019.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2019 through December 2019?

A. Yes. Exhibit No. PAR-4, 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 the O&M and capital expenditures that support the development of the environmental cost recovery factors for 2019. I have also provided Exhibit No. PAR-5, which contains four documents, including selected schedules without the costs of Tampa Electric's two new proposed ECRC projects for compliance with the Effluent Limitations Guidelines

("ELG") Rule and Section 316(b) of the Clean Water Act.

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

A. Yes. The company requests approval of the ECRC factors provided in Exhibit No. PAR-4, Document No. 7, on Form 42-7P. The factors were prepared under my direction and supervision. These annualized factors will apply for the period January 2019 through December 2019.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2019 to December 2019?

A. The net true-up applicable for this period is an over-recovery of $14,971,149. This consists of a final true-up over-recovery of $1,498,666 for the period of January 2017 through December 2017 and an estimated true-up over-recovery of $13,472,483 for the current period of January 2018 through December 2018. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-9E of Exhibit No. PAR-2 filed with the Commission on July 25, 2018.

Q. Did Tampa Electric include any new environmental compliance projects for ECRC cost recovery for the period from January 2019 through December 2019?

A. Yes, Tampa Electric included costs associated with the company's compliance with Section 316(b) of the Clean Water Act. The company's petition for approval to recover such costs through the ECRC was filed with the Commission on April 26, 2018. In addition, costs associated with compliance with the company's Effluent Limitations Guidelines Program ("ELG") have been included. The company's petition for approval to recover such costs through the ECRC was filed with the Commission on May 9, 2018. Tampa Electric's witness Paul L. Carpinone supports the need for the projects, as detailed in his direct testimony submitted on July 25, 2018 in this docket.

Q. What are the capital projects included in the calculation of the ECRC factors for 2019?

A. Tampa Electric proposes to include for ECRC recovery costs for the 27 previously approved capital projects along with the two new projects in the calculation of the 2019 ECRC factors. These projects are listed below.

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 NOx 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) Big Bend Coal Combustion Residuals (“CCR”) Rule – Phase I

27) Big Bend CCR Rule - Phase II

28) Big Bend Unit 1 Section 316(b)Impingement Mortality

29) Big Bend Effluent Limitations Guidelines (“ELG”) Rule Compliance

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2019?

A. Yes. Form 42-3P contained in Exhibit No. PAR-4 summarizes the cost estimates for these projects. Form 42-4P, pages 1 through 29, provides the calculations resulting in recoverable jurisdictional capital costs of $45,357,454.

Q. What are the O&M projects included in the calculation of the ECRC factors for 2019?

A. Tampa Electric proposes to include for ECRC recovery O&M costs for 25 previously approved O&M projects and two new projects in the calculation of the ECRC factors for 2019. These projects are listed below.

1) Big Bend Unit 3 FGD Integration

2) Big Bend Units 1 and 2 Flue Gas Conditioning

3) SO_2 Emission Allowances
4) Big Bend Units 1 and 2 FGD
5) Big Bend PM Minimization and Monitoring
6) Big Bend NO_x Emissions Reduction
7) National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees
8) Gannon Thermal Discharge Study
9) Polk NO_x Emissions Reduction
10) Bayside SCR Consumables
11) Big Bend Unit 4 Separated Overfired Air ("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) Big Bend CCR Rule Phase I
24) Big Bend CCR Rule Phase II25) Big Bend Unit 1 Section 316(b) Impingement Mortality

26) Big Bend ELG Rule Compliance

Q. Have you prepared a schedule showing the calculation of the recoverable O&M project costs for 2019?

A. Yes. Form 42-2P contained in Exhibit No. PAR-4 presents the recoverable jurisdictional O&M costs for these projects, which total $12,562,528 for 2019.

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 are provided in Form 42-5P, pages 1 through 34.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2019?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P of Exhibit No. PAR-4. These expenditures total $57,919,982.

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 and energy allocation factors were determined by calculating the percentage that each rate class contributes to the total demand or energy and then adjusted for line losses for each rate class. This information was calculated by applying historical rate class load research to 2019 projected 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 January 2019 through December 2019 which Tampa Electric is seeking approval?

A. The computation of billing factors is shown in Exhibit No. PAR-4, Document No. 7, Form 42-7P. The proposed ECRC billing factors are summarized below.

Rate Class	Factors by Voltage Level (¢/kWh)
RS Secondary	0.222
GS, CS Secondary	0.221
GSD, SBF	
Secondary	0.220
Primary	0.218

Rate Class	**Factors by Voltage Level (¢/kWh)**
GSD, SBF, continued	
Transmission	0.216
IS	
Secondary	0.217
Primary	0.214
Transmission	0.212
LS1	0.217
Average Factor	0.221

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 2019.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2019 through December 2019?

A. Tampa Electric used the weighted average cost of capital methodology approved by the Commission in Order Nos. PSC-2012-0425-PAA-EU and PSC-2017-0456-S-EI to calculate the revenue requirement rate of return found on Form 42-8P.

Q. Have you incorporated the tax rate change from the Tax Cut and Job Act of 2017 into the company’s calculated revenue requirement rate of return effective January 1, 2018?

A. Yes.

Q. Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2019 through December 2019 consistent with the criteria established for ECRC recovery in Order No. PSC-1994-0044-FOF-EI?

A. Yes. The costs for which ECRC recovery 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 were based; and,
3) Such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. Please summarize your direct testimony.

A. My testimony supports the approval of a final average ECRC billing factor of 0.221 cents per kWh. This includes the projected capital and O&M revenue requirements of $57,919,982 associated with the company’s 36 ECRC projects and a net true-up over-recovery provision of $14,971,149. My testimony also explains that the projected environmental expenditures for 2019 are appropriate for recovery through the ECRC.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PAUL L. 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 Services in the Environmental Services 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. In 2006, I became Director of Environmental Services. My responsibilities include the development and administration of the company's environmental policies and goals. I am also responsible for ensuring resources, procedures and programs meet or surpass compliance with applicable environmental requirements, and that rules and polices are in place and functioning appropriately and consistently throughout the company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide record support for the Commission's approval of two environmental programs for cost recovery through the Environmental Cost Recovery Clause ("ECRC"). Those projects include the company's Big Bend Unit 1 Section 316(b) Impingement Mortality Project ("Impingement Mortality Project") and the company's Big Bend Station Effluent Limitations Guidelines Rule Compliance Program ("Big Bend ELG Rule Compliance Program").

Impingement Mortality Project

Q. Please describe the environmental requirements necessitating the Impingement Mortality Project?

A. In August 2014 the Environmental Protection Agency ("EPA") published their final rule regarding Section 316(b) of the Clean Water Act. The rule became effective in October 2014. The rule establishes requirements for cooling water intake structures ("CWIS") at existing facilities. Section 316(b) requires that the location, design, construction and capacity of CWIS reflect the best technology available ("BTA") for minimizing adverse environmental impacts.

The rule addresses impacts to aquatic life resulting from operation of cooling water systems in the U.S. from either impingement or entrainment. Impingement mortality occurs when fish and shellfish are pinned against the intake system screens and unable to get free. Entrainment mortality occurs when small fish, eggs, and larvae pass through the protective screens and into the cooling system. The rule allows for seven different approaches to impingement mortality reduction at affected facilities, each of which, if it meets the goals defined for the approach by the rule, would be considered fully compliant. These approaches are

a. closed-cycle cooling tower;
b. 0.5 feet per second ("fps") through-screen design velocity;
c. 0.5 fps through-screen actual velocity;
d. existing offshore velocity cap;

e. modified traveling screens;

f. system of technologies as the BTA for impingement mortality; and,

g. meet impingement mortality performance standard.

For entrainment compliance, the rule requires the evaluation of closed-cycle cooling, alternative water supplies, and fine mesh screens in terms of feasibility, cost, and effectiveness for a site-specific determination by the Florida Department of Environmental Protection ("FDEP") Director. With respect to Big Bend Station, the FDEP Director will make this determination by reviewing the following study elements which are required to be submitted with the National Pollutant Discharge Elimination System ("NPDES") permit renewal application. These elements are:

a. 40 CFR 122.21(r)(2), Source Water Physical Data;

b. 40 CFR 122.21(r)(3), Cooling Water Intake Structure Data;

c. 40 CFR 122.21(r)(4), Baseline Biological Characterization;

d. 40 CFR 122.21(r)(5), Cooling Water System Data;

e. 40 CFR 122.21(r)(6), Chosen Method of Compliance with Impingement Mortality Standard;

f. 40 CFR 122.21(r)(7) Entrainment Performance Studies; and,

g. 40 CFR 122.21(r)(8) Operational Status.

h. 40 CFR 122.21(r)(9), Entrainment Characterization Study;

i. 40 CFR 122.21(r)(10), Feasibility and Cost Study;

j. 40 CFR 122.21(r)(11), Benefits Valuation Study;

k. 40 CFR 122.21(r)(12) Environmental and Other Impacts; and,

l. 40 CFR 122.21(r)(13) Peer Review of (r)(10), (r)(11), and (r)(12).

Tampa Electric continues to perform the required studies under its previously approved Clean Water Act Section 316(b) Phase II Study ECRC project.

As stated above, compliance with Section 316(b) is tied to the renewal of the NPDES permit for the facility; however, the rule included a provision to allow a request for an alternative schedule for those facilities that had permit renewal dates within 45 months of the finalization of the rule. Big Bend Station requested such an alternative schedule to allow time to complete the study elements. Within six months of the finalization of the company's Big Bend Station NPDES permit, which is currently undergoing renewal by the FDEP, Tampa Electric will submit a plan of study which will be used by FDEP to establish the compliance schedule. However, the modernization of Big Bend Unit 1 to a highly efficient, natural gas-fired unit (the "Big Bend Unit 1 Modernization") requires NPDES permit modifications, and FDEP has agreed that it is appropriate to address impingement mortality in conjunction with the Big Bend Unit 1 Modernization. In addition, complying with the rule requirements now will benefit customers because integrating the impingement mortality equipment into the Big Bend Unit 1 Modernization project planning, design, and construction work will be more efficient than retrofitting the unit with the impingement mortality compliance equipment at a later date due to the additional outage time that would be needed to perform the modifications later.

Q. What is the specific scope of the company's petition for approval of the Impingement Mortality Project?

A. The petition applies to impingement mortality requirements of Section 316(b) for the CWIS currently shared by Big Bend Units 1 and 2. If the company's Clean Water Act Section 316(b) Phase II Study results indicate that additional changes are needed to meet entrainment mortality requirements, this new system will accommodate installation of fine mesh screens, and cost recovery for such work would be addressed in a separate request. In addition, impingement and entrainment mortality compliance for Big Bend Units 3 and 4 will need to be addressed at a later date based on the results of the studies the company is performing under its Clean Water Act Section 316(b) Phase II Study ECRC project and the NPDES permit renewal.

Q What actions must the company take in order to comply with Rule 316(b) and the company NPDES permit?

A. In order to comply with Rule 316(b) and its NPDES permit, Tampa Electric must make modifications to its existing CWIS shared by Big Bend Units 1 and 2 for purposes of withdrawing once-through cooling water from Tampa Bay. Each unit is currently equipped with two 50 percent cooling water pumps which have dedicated traveling screens to protect the pumps against entrainment of debris. This intake structure will be modified to operate with the modernized Big Bend Unit 1, and new dual flow modified traveling screens as well as a fish collection and return system will be installed to comply with the impingement mortality requirements of Section 316(b). The new system will allow aquatic life impinged on the screens to be safely returned to a suitable location.

The company hired an engineering firm to conduct studies to evaluate Section 316(b) impingement mortality compliance and has identified the modified traveling screens with fish return as the most cost-effective solution to continue operating Big Bend Unit 1 in compliance with Section 316(b). The selected solution complies with option (e) in the list of compliance options stated above.

Engineering work for the Big Bend Unit 1 Section 316(b) Impingement Mortality project began mid-year in 2018 to support equipment procurement and a construction start date in 2021 when Big Bend Units 1 and 2 will be shut down for the modernization project work. The Impingement Mortality Project will be completed prior to commercial operation of the Big Bend Unit 1 Modernization in January 2023.

Q. Please describe the costs of the Impingement Mortality Project.

The total estimated cost of the project is $15.6 million. The following table reflects a breakdown of the project components and their projected costs.

Big Bend Unit 1 Section 316(b) Impingement Mortality Project

	2018 ($000)	2019 ($000)	2020 ($000)	2021 ($000)	2022 ($000)	2023 ($000)	Total ($000)
Capital							
Engineering	1,650	-	-	-	-	-	1,650
Equipment	325	3,000	500	-	-	-	3,825
Construction	-	-	-	500	7,750	250	8,500
Owners Costs	500		500	500	-	-	1,500
Demolition / Retirement	-	-	-	-	170	-	170
Total	2,475	3,000	1,000	1,000	7,920	250	15,645
In-Service Annual O&M[1]							
Variable O&M	-	-	-	-	-	67	
Operating Labor	-	-	-	-	-	25	
Maintenance Material	-	-	-	-	-	99	
Maintenance Labor	-	-	-	-	-	65	
Total	-	-	-	-	-	256	

1 Estimated annual O&M expense after commercial in-service date, in 2023 dollars.

Q. What steps will the company take to ensure that the costs of the project are reasonable?

A. Tampa Electric will follow its usual prudent and practical procurement policies, including competitive bidding for project components, to ensure it purchases equipment and services at the best prices available. These estimated annual costs may vary due to timing of the work and will continue to be refined as design and engineering work progresses. Tampa Electric will provide updated cost estimates in its annual ECRC filings.

Q. Is the proposed project essential to enable the company to comply with applicable environmental mandates?

A. Yes. Tampa Electric cannot continue operating Big Bend Unit 1 in compliance with Section 316(b) without making the CWIS modifications I have described. Section 316(b) compliance requires these modifications regardless of whether Big Bend Unit 1 is modernized to a natural gas-fired unit or continues to operate as coal-fired.

Q. What is the Commission's policy governing ECRC cost recovery?

A. The Commission's policy for initial cost recovery approval of an ECRC eligible project is set forth in Order No. PSC-94-0044-FOF-EI issued January 12, 1994 in Docket No. 930613-EI, In re: Gulf Power Company, ("the Gulf Order") as follows:

> Upon petition, we shall allow the recovery of costs associated with an environmental compliance activity through the environmental cost recovery factor if:
>
> 1. such costs were prudently incurred after April 13, 1993:
> 2. the activity is 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. Does the Impingement Mortality Project qualify for ECRC cost recovery under these principles?

A. Yes. The proposed CWIS modifications merit ECRC cost recovery under the criteria set forth by the Commission in the Gulf Order. All costs associated with the project will be prudently incurred after April 13, 1993. The CWIS modifications to Big Bend Unit 1 are required in order for Tampa Electric to continue complying with the requirements of Section 316(b) and its NPDES permit. The need to construct CWIS modifications has been triggered after the company's last test year upon which rates are currently based. Finally, the costs of the proposed CWIS modifications are not recovered through some other cost recovery mechanism or through base rates. Like the Gulf Power ECRC project approved in Docket No. 980007-EI, the proposed CWIS modifications are needed in order to enable

Tampa Electric to continue complying with applicable environmental mandates.

Q. What is the schedule for the project?

A. Tampa Electric expects to begin incurring 316(b) impingement mortality compliance costs associated with the proposed CWIS modifications for Big Bend Unit 1 in 2018. Project costs will be subject to audit by the Commission.

Q. How should the projects costs be allocated?

A. The project capital expenditures should be allocated to rate classes on a demand basis, and operation and maintenance expenses should be allocated to rate classes on an energy basis.

<u>Big Bend ELG Rule Compliance Program</u>

Q. Please describe the Big Bend ELG Rule Compliance Program?

A. The Big Bend ELG Rule Compliance Program is designed to enable Tampa Electric to comply with the Environmental Protection Agency's legally required ELG rule.

On November 3, 2015 the Environmental Protection Agency

("EPA") published the final Steam Electric Power Generating Effluent Limitations Guidelines ("ELG") in the Federal Register. The effective date of the rule is January 4, 2016. The ELG establish limits for wastewater discharges from flue gas desulfurization ("FGD") processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals ("CCR"), gasification processes, and flue gas mercury controls. The final rule requires compliance as soon as possible after November 1, 2018, and no later than December 31, 2023. Since these limitations will be incorporated in the National Pollutant Discharge Elimination System ("NPDES") permits, the exact compliance date will be determined through discussions with the Florida Department of Environmental Protection ("FDEP"), whom EPA has delegated to administer these permits. EPA extended the near-term deadlines for FGD waste water and bottom ash transport water to as soon as possible after November 1, 2020, while those limits are under consideration.

Q. What Tampa Electric facilities are affected by the ELG Rule?

Tampa Electric facilities located at the company's Big Bend Station are affected by the ELG Rule. Big Bend Station operates four coal-fired steam electric power generating units equipped with electrostatic precipitators, Selective Catalytic Reduction ("SCR") and wet Limestone Forced Oxidized ("LSFO") Flue Gas Desulfurization ("FGD") systems. The FGD system is designed to operate at a chloride concentration of no more than 30,000 ppm chlorides. Chloride control is obtained by blowing down the FGD system at approximately 230 gpm. This blow-down stream is 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.

Other ELG waste stream categories present at Big Bend Station are bottom and fly ash transport water, which will be used for FGD scrubber make-up water, as allowed by the ELG Rule. There are no other facilities at Big Bend Station affected by the ELG Rule.

Q. Please describe the Big Bend ELG Study Program.

A. On February 2, 2016 Tampa Electric Company submitted its Petition for Approval of its Big Bend ELG Study Program for cost recovery through the Environmental Cost Recovery Clause. The Big Bend ELG Study Program was needed to determine the most appropriate ELG compliance measure for that station. The Big Bend ELG Study Program was approved in Order No. PSC-16-0248-PAA-EI issued June 28, 2016 in Docket No. 20160027-EI, and confirmed in Consummating Order No. PSC-16-0290-CO-EI issued July 25, 2016 in Docket No. 20160027-EI.

The Study identified the technically and commercially available technologies which could be viable candidates to treat the Tampa Electric Big Bend Station combined effluent streams in order to bring the streams into compliance with the more stringent requirements under the ELG Rule. The company has reviewed several options and selected the deep well injection solution based on total project costs, including annual operating costs. This option allows the company to use one option to comply with ELG Rule parameters. Although capital costs for the options considered varied, the deep well injection solution is one of the least costly when capital costs and annual operating costs are considered. Combined with the fact that the deep well injection solution does not degrade unit performance as other options do, it is the best choice for Tampa Electric's Big Bend Station ELG Rule compliance.

With the Study now completed, the company must obtain environmental permitting and engage in the construction of a test injection well to ensure that the selected deep well injection method satisfies FDEP requirements. Once the test results are confirmed, the test injection well will be converted to a permanent deep injection well system of two wells to comply with the ELG Rule. Obtaining Commission approval for recovery of permitting, engineering, and construction costs for both the test well and the permanent deep injection well systems is the purpose of this section of my testimony.

Q. What are the estimated costs of the Big Bend Station ELG Rule Compliance Program for which Tampa Electric is requesting ECRC recovery?

A. Tampa Electric requests recovery of capital costs, estimated to be in a range of from $18 million to $26 million, for preconstruction design, engineering, permitting, and installation of two injection wells, together with one of three options the company is considering for pretreatment of the effluent discharge. The pretreatment requirement will be determined after the FDEP review of the test well results. The capital costs could range from an estimated $18 million if no water softening is required and the company's permit allows blending wastewater with county-treated effluent, to approximately $21 million if 30 percent softening is required, and up to approximately $26 million if full softening treatment is required. For purposes of illustration, the following table describes the component capital costs for the option of deep well injection with the pretreatment of 30 percent softening of the water prior to injection.

Capital Costs by Year

Deep Injection Wells with Pre-Treatment of 30% Water Softening

	2018 ($000)	2019 ($000)	2020 ($000)	2021 ($000)	Total ($000)
Capital					
Permitting and Pre-Construction Engineering Design	150	250	700	-	1,100
Construction Engineering	-		1,800	400	2,200
Well Construction (2 wells)	-		5,000	3,000	8,000
Water Treatment (Softening)	-		7,100	2,600	9,700
Total	150	250	14,600	6,000	21,000

The permit application for deep well injection will be submitted to the FDEP and will address testing, hydro-geological impacts, and construction specifications. The cost estimates above estimate that permitting will be completed in 2019, and well engineering and construction costs will commence in 2019. Tampa Electric anticipates well construction will take approximately one year to complete.

After the test well is installed and reviewed, the company will proceed to obtain permanent deep well injection permits, convert the test well into a permanent deep injection well, and construct a second well. The deep well injection solution includes two permanent wells because a well must be available at all times for the Big Bend Station units’ FGD systems to operate, and operation of the FGD systems is an environmental requirement to run the generating units. In addition, when maintenance is needed on one of the deep injection wells, another well must be available in order to run the units.

O&M expenses will be incurred after the wells are in operation, with annual costs for 30 percent softening expected to be $1.9 million annually. The O&M expenses of the other treatment options under consideration are shown in the following table. The treatment option selected will depend on FDEP’s test well review and requirements for permanent well permits. These estimated annual costs may be revised due to timing of the work and will continue to be refined as design and engineering work progresses. Tampa Electric will provide updated cost estimates in its annual ECRC filings.

Total Capital and Annual O&M Costs

Deep Injection Wells with Various Pre-Treatment Options

	Capital Cost	Annual Operating Cost
	($000)	($000)
Deep well injection - with 30% softening	21,000	1,900
Deep well injection - with full softening	26,000	4,500
Deep well injection – with effluent blending	18,000	700

Q. Does this program qualify for cost recovery under the Commission's ECRC policies of the Gulf Order described earlier in your testimony?

A. Yes. Tampa Electric's Big Bend ELG Compliance Program qualifies for ECRC cost recovery under the Gulf Order. The costs of the program will be prudently incurred after April 13, 1993. The company's planned activities under the Big Bend ELG Compliance Program are essential components of the company's ability to comply with the EPA's legally required ELG Rule which was adopted and became effective after the company's last test year upon which rates are based. None of the costs proposed under the Big Bend ELG Compliance Program are recovered through some other cost recovery mechanism or through base rates.

Q. How should program costs be allocated?

A. This program is a compliance activity associated with limitations on wastewater discharge. Capital costs to implement the modified Big Bend ELG Compliance Program should be allocated to rate classes on a demand basis, and operation and maintenance costs should be allocated to rate classes on an energy basis. Estimated costs will be further refined during engineering work, and the project cost estimates will be updated in future filings with the Commission.

Q. Please summarize your testimony.

A. My testimony supports Commission approval for ECRC cost recovery purposes of Tampa Electric's Section 316(b) Impingement Mortality Project and its proposed Big Bend ELG Rule Compliance Program. Both programs meet the Commission's policy governing ECRC cost recovery as set forth in the Gulf Order. The costs of each program will be prudently incurred after April 13, 1993. The activities in these programs 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. Finally, such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180007-EI
FILED: 08/24/2018

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PAUL L. 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 Services in the Environmental Services 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 Services. My responsibilities include the development and administration of the company’s environmental policies and goals. I am also responsible for ensuring resources, procedures and programs meet or surpass compliance with applicable environmental requirements, and that rules and polices 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 2019 through December 2019 projection period are activities related to programs previously approved or for which petitions are pending approval by the Commission for recovery through the ECRC. For those where a petition is pending approval, the projects meet the criteria for ECRC recovery relevant to this docket, as established by Order No. PSC-1994-0044-FOF-EI.

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 (0570039-110-AV). The projects that are now required under the operating permit are listed below.

- Big Bend PM Minimization Program
- Big Bend NO_x 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 2019 through December 2019.

A. The Big Bend PM Minimization and Monitoring Program was approved by the Commission in Docket No. 20001186-EI, Order No. PSC-2000-2104-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 2019; however, the O&M expenses associated with existing and recently installed Best Operating Practice (BOP) and best available control technology (“BACT”) equipment and continued implementation of the BOP procedures are expected to be $398,500.

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 2019 through December 2019.

A. The Big Bend NO_x Emission Reduction program was approved by the Commission in Docket No. 20001186-EI, Order No. PSC-2000-2104-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 2019; however, the company will perform maintenance on the previously approved and installed NO_x reduction equipment. This activity is expected to result in approximately $60,000 of O&M expenses during 2019.

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 2019 through December 2019.

A. In Docket No. 20040750-EI, Order No. PSC-2004-0986-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. 20041376-EI, Order No. PSC-2005-0502-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. Those Pre-SCR technologies include windbox modifications, secondary air controls and coal/air flow controls. The SCR projects at Big Bend Unit 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 2019 through December 2019, 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 $6,000 for Big Bend Unit 1 Pre-SCR, $6,000 for Big Bend Unit 2 Pre-SCR, and $6,000 for Big Bend Unit 3 Pre-SCR for equipment maintenance. There are not any anticipated capital expenditures for Big Bend Units 1, 2, or 3 SCRs; however, the capital expenditures for Big Bend

Unit 4 SCR is projected to be $2,100,000, for catalyst replacement. Additionally, the O&M expenses are projected to be $167,240 for Big Bend Unit 1 SCR, $261,200 for Big Bend Unit 2 SCR, $396,460 for Big Bend Unit 3 SCR and $2,135,100 for Big Bend Unit 4 SCR. These expenses are primarily associated with ammonia purchases.

Q. Please identify and describe the other Commission-approved programs, or those pending Commission approval, that 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 Limitations Guidelines Study

The programs pending Commission approval that I will discuss include the following projects:

13) Big Bend Unit 1 Section 316(b) Impingement Mortality
14) Effluent Limitations Guidelines Rule Compliance Program

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 2019 through December 2019.

A. The Big Bend Unit 3 FGD Integration program was approved by the Commission in Docket No. 19960688-EI, Order No. PSC-1996-1048-FOF-EI, issued August 14, 1996. The Big Bend Units 1 and 2 FGD program was approved by the Commission in Docket No. 19980693-EI, Order No. PSC-1999-0075-FOF-EI, issued January 11, 1999. In these 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 2019 through December 2019 for the Big Bend Unit 3 FGD Integration project; however, O&M expenses are projected to be $709,500 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 2019 through December 2019; however, the O&M expenses are projected to be $680,000 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 2019 through December 2019.

A. The Gannon Thermal Discharge Study program was approved by the Commission in Docket No. 20010593-EI, Order No. PSC-2001-1847-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 2019 through December 2019, 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. Bayside Power Station applied for renewal of the National Pollutant Discharge Elimination System ("NPDES") Permit in February 2018, and at this time, the company anticipates that an additional thermal study will not be required. If a thermal study is required, Tampa Electric will incur O&M expenses and will include them in the true-up filing.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated O&M expenditures for the period of January 2019 through December 2019.

A. The Bayside SCR Consumables program was approved by the Commission in Docket No. 20021255-EI, Order No. PSC-2003-0469-PAA-EI, issued April 4, 2003. For the period of January 2019 through December 2019, Tampa Electric projects O&M expenses associated with the consumable goods (primarily anhydrous ammonia) to be approximately $119,000.

Q. Please describe the Clean Water Act Section 316(b) Phase II Study Program and the associated Big Bend Unit 1 Section 316(b) Impingement Mortality Project activities and provide the estimated capital and O&M expenditures for the period of January 2019 through December 2019.

A. The Clean Water Act Section 316(b) Phase II Study program was approved by the Commission in Docket No. 20041300-EI, Order No. PSC-2005-0164-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. The rule establishes requirements for CWIS at existing facilities. Section 316(b) requires that the location, design, construction and capacity of CWIS reflect the best technology available ("BTA") for minimizing adverse environmental impacts. Tampa Electric is currently finalizing its compliance strategy for the CWIS Rule at Big Bend 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. However, for Big Bend Unit 1, which will be repowered to a clean, natural gas-fired combined cycle unit, the permit will require installation of the impingement mortality controls as part of the modernization project. Completing the work during the repowering activities will also reduce overall costs because an additional outage will not be needed to retrofit the unit to comply with Section 316(b) impingement mortality requirements at a later date.

The biological, financial, and technical study elements have been identified for Bayside Power Station and submitted with the NPDES permit renewal application in February 2018. Retrofits could include the installation of cooling towers or screening facilities. All costs associated with the Section 316 (b) study have been incurred, unless additional information is required by the regulatory agencies.

Tampa Electric filed its petition for Commission approval of the Big Bend Unit 1 Section 316(b) Impingement Mortality project in early 2018, and I submitted testimony in support of the project on July 25, 2018 under this docket. For the period of January 2019 through December 2019, Tampa Electric projects capital expenditures for the Big Bend Unit 1 Section 316(b) Impingement Mortality Project to be $3,000,000. There are no O&M expenses anticipated during 2019.

Q. Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital expenditures for the period of January 2019 through

December 2019.

A. Tampa Electric's Big Bend FGD System Reliability program was approved by the Commission in Docket No. 20050958-EI, Order No. PSC-2006-0602-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 the SCR systems on the generating units. For the period of January 2019 through December 2019, there are no 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 2019 through December 2019.

A. The Arsenic Groundwater Standard program was approved by the Commission in Docket No. 20050683-EI, Order No. PSC-2006-0138-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 for prudently incurred costs. This groundwater standard applies to Tampa Electric's Bayside, Big Bend, and Polk Power Stations.

For the period of January 2019 through December 2019, there are no anticipated O&M expenses at Bayside or Polk Power Stations. Although no O&M expenses are currently anticipated for Big Bend Power Station in 2019, a detailed plan of study has been submitted to the FDEP for review, which may refine the program’s scope of work and require future expenditures.

Q. Please describe the MATS program activities.

A. The MATS program was approved by the Commission in Docket 20120302-EI, Order No. PSC-2013-0191-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 record keeping requirements. Additionally, monitoring of acid gases and particulate matter is 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 MATS program estimated capital and O&M expenditures for the period of January 2019 through December 2019.

A. For 2019, Tampa Electric anticipates capital expenditures of $275,000 under the MATS program for monitoring equipment. O&M expenditures are projected to be approximately $74,880 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 2019 through December 2019.

A. Tampa Electric's GHG Reduction program was approved by the Commission in Docket No. 20090508-EI, Order No. PSC-2010-0157-PAA-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 for the first time in 2011. Reporting for the EPA's Greenhouse Gas Mandatory Reporting rule will continue in 2019. For 2019, this activity is projected to result in approximately $93,150 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 2019 through December 2019.

A. The Big Bend Gypsum Storage Facility program was approved by the Commission in Docket No. 20110262-EI, Order No. PSC-2012-0493-PAA-EI, issued in 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 2019, Tampa Electric does not anticipate any capital expenditures; however, the projected O&M expenses for this program during 2019 are $1,320,000.

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 2019 through December 2019.

A. On April 17, 2015, the EPA issued a final rule to regulate coal combustion residuals ("CCRs") as non-hazardous 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, the East Coalfield Stormwater Pond (converted former slag fines pond) and the North Gypsum Stackout Area are regulated under the rule.

The initial phase of the company's CCR compliance was approved by the Commission in Docket No. 20150223-EI, Order No. PSC-2016-00994-PAA-EI, issued on February 9, 2016. In that Order, the Commission found that the CCR Rule – Phase I program met the requirements for recovery through the ECRC. Incremental ongoing O&M expenses resulting from the groundwater monitoring program, berm inspections and general maintenance of regulated units were approved under the Order. In order to determine the best option to remain in compliance with the new rule, the company evaluated whether to continue operation of the regulated CCR units or to close them. Tampa Electric, for Phase II of the project, chose a combination of closure and retrofit projects to remain in compliance with the CCR Rule, as discussed later in this section.

Two CCR retrofit projects were also approved for Tampa Electric’s Phase I CCR program under Order No. PSC-2016-00994-PAA-EI. These included: 1) removal of remaining residual slag from the East Coalfield Stormwater Runoff Pond and lining the pond to continue operating it as part of the Station’s stormwater system; and 2) installing secondary stormwater containment facilities and lining drainage ditches for the North Gypsum Stackout Area to make it fully compliant with the rule’s requirements.

Phase II of Tampa Electric’s CCR program was approved by Commission Order No. 2017-0483-PAA-EI issued in Docket No. 20170168-EI on December 22, 2017. In that Order, the Commission found that the Phase II program met the requirements for recovery through the ECRC. Expenses for the CCR Economizer Ash Pond System Closure Project, which includes removal and offsite disposal of all CCRs and restoration of the area to original grade, were approved by the Commission’s Order.

The Economizer Ash Pond System Closure Project is expected to begin in the fourth quarter of 2018 with initial dewatering and removal of CCRs for disposal. Due to the large amount of CCRs in the Economizer Ash Ponds which will need to be dewatered and shipped to the landfill, this project is expected to continue through 2021. The East Coalfield Stormwater Runoff Pond (slag pond) closure and retrofit project is scheduled to begin in the first half of 2019 and completed by the end of 2019. The North Gypsum Stackout Area Drainage Improvements Project is expected to commence in 2019 and be completed in early 2020.

Tampa Electric expects to incur $2,100,000 and $230,000 in 2019 capital expenditures for CCR Rule Phase I and Phase II projects, respectively. The company expects to incur $6,000,000 for O&M expenses for the CCR Rule - Phase II project. There are no O&M expenses projected for CCR Rule – Phase I during 2019.

Q. Please describe Tampa Electric’s Effluent Limitations Guidelines activities, both study and compliance related, and provide the estimated capital and O&M expenditures for the period of January 2019 through December 2019.

A. On November 3, 2015, the EPA published the final Steam Electric Power Generating Effluent Limitations Guidelines ("ELG"), 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 to achieve compliance with the new EPA regulations. The rule requires compliance after November 1, 2018, but no later than December 31, 2023. EPA issued a temporary stay of these compliance deadlines (beginning April 25, 2017) for certain waste streams, including FGD wastewater.

The Big Bend ELG Study Program ("Study") was approved in Order No. PSC-2016-0248-PAA-EI issued June 28, 2016 in Docket No. 20160027-EI, and confirmed in Consummating Order

No. PSC-2016-0290-CO-EI issued July 25, 2016 in Docket No. 20160027-EI.

The Study, which was completed in 2018, identified viable technologies to treat the Tampa Electric Big Bend Station combined effluent streams in order to bring the streams into compliance with the more stringent requirements under the ELG Rule and resulted in the selection of the deep well injection solution.

Tampa Electric filed its petition for Commission approval of the ELG Rule Compliance Program in early 2018, and I submitted testimony in support of the project under this docket on July 25, 2018. The company expects to begin permitting and design activities in 2018.

On June 6, 2017, the EPA issued proposed rulemaking to postpone these deadlines until it has completed reconsideration of the 2015 rule. On August 11, 2017, EPA issued a letter to the Utility Water Act Group ("UWAG") and the U.S. Small Business Association regarding petitions received by the EPA requesting reconsideration of the rule. In this letter, EPA stated that it would be appropriate to conduct rulemaking to "potentially revise" the limitations for bottom ash transport water and FGD wastewater. The compliance deadlines for these wastestreams were revised to be as soon as possible after November 1, 2020, but no later than December 31, 2023. Tampa Electric expects that the selected compliance option will continue to be required as the best option for customers even if some changes are made to the rule. Tampa Electric does not currently project any O&M or capital expenditures for this project for the period January 2019 through December 2019.

Q. Please summarize your testimony.

A. The settlement agreements Tampa Electric had with FDEP and EPA required significant reductions in emissions from Big Bend and Gannon Power Stations. These settlement agreements 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 have been incorporated into Big Bend's Title V Operating permit (0570039-110-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 2019. Additionally, my testimony identified other projects that are required for Tampa Electric to meet environmental requirements, and I provided the associated 2019 activities and projected expenditures.

Q. Does this conclude your direct testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony
Richard M. Markey
Docket No. 20180007-EI
Date of Filing: April 2, 2018

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. 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 2017, 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 Environmental Cost Recovery Clause (ECRC) final true-up for the period January 2017 through December 2017.

Q. Mr. Markey, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2017 through December 2017 with the approved estimated true-up amounts.

A. As reflected in Mr. Boyett's Schedule 6A, the actual recoverable capital costs were $166,509,924 as compared to $166,467,793 included in the Estimated True-up filing. This resulted in a net variance of $42,132 over the estimated true-up projection.

Q. How do the actual O&M expenses for the period January 2017 to December 2017 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 $37,803,638**,** as compared to the estimated true-up of $39,672,854. This resulted in a variance of $1,869,216 or 4.7% under the estimated true-up. I will address eight O&M projects and/or programs that contribute to this variance: Emissions Monitoring, General Water Quality, Groundwater Contamination Investigation, General Solid & Hazardous Waste, Air Quality Compliance Program, Crist Water Conservation, Coal Combustion Residual (CCR), and Smith Water Conservation.

Q. Please explain the variance of ($81,698) or (10.2%) in (Line item 1.5), Emissions Monitoring.

A. This line item includes expenses associated with the Environmental Protection Agency's (EPA) requirements that the Company perform Quality Assurance/Quality Control (QA/QC) testing for the Continuous Emissions Monitoring System (CEMS), including Relative Accuracy Test Audits (RATAs) and Linearity Tests. This variance is primarily due to lower actual costs associated with emissions monitoring reporting.

Q. Please explain the variance of ($467,356) or (16.1%) in (Line item 1.6), General Water Quality.

A. This line item includes expenses related to National Pollutant Discharge Elimination System (NPDES) permit compliance, Dechlorination, Groundwater Monitoring and Assessment, Surface Water Studies, the Cooling Water Intake Program, the Impoundment Integrity Program, and Stormwater Maintenance. The line item variance is primarily due to two factors: (1) minimal maintenance expenses required for the Plant Crist impoundment integrity program ($245,000); and (2) O&M costs for the Plant Crist groundwater remediation system being less than projected in the Estimated True-Up filing ($156,000).

Q. Please explain the variance of ($219,767) or (6.8%) in (Line item 1.7), Groundwater Contamination Investigation.

A. This line item includes expenses related to substation investigation and remediation activities. This variance is due to a reduction in excavation costs. Excavation costs were reduced because the extent of excavation activities were less than expected due to the presence of utility infrastructure in the remediation area as well as less site contamination than expected.

Q. Please explain the variance of ($374,550) or (31.6%) in (Line item 1.11), General Solid & Hazardous Waste.

A. This line item includes expenses for proper identification, handling, storage, transportation and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. This variance is primarily due to costs associated with transformer oil spills and associated disposal costs for Gulf's power delivery operations that were less than projected.

Q. Please explain the O&M variance of $660,626 or 2.9% 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 Scherer Unit 3 scrubber, Plant Crist Unit 6 Selective Catalytic Reduction (SCR) and Plant Scherer Unit 3 SCR and baghouse. More specifically, this line item includes the cost of ammonia, urea, limestone, and the general operation and maintenance activities associated with Gulf's Air Quality Compliance Program. This variance is primarily due to expensing approximately $2,194,000 of preliminary engineering and design (PS&I) costs associated with the Plant Daniel Units 1 and 2 SCRs in 2017. The Plant Daniel SCRs were identified in Gulf's 2010 Compliance Plan Update as needed in the 2014-2015 timeframe to meet the requirements of the Clean Air Interstate Rule (CAIR), the anticipated 8-hour ozone nonattainment designation, and anticipated mercury Maximum Achievable Control Technology (MACT) requirements. Gulf filed a petition on April 1, 2010, requesting recovery of costs associated with the Daniel SCRs through the ECRC, which was ultimately approved in FPSC Order No. PSC-10-0683-FOF-EI. The SCRs were projected to have a three to five-year construction timeframe; therefore, PS&I work began in advance to enable Gulf to meet the expected compliance deadline. Since the Commission's approval, there have been a number of regulatory and legislative developments that Gulf has addressed in several of its ECRC filings and annual updates, which included changes to re-project the SCR project schedules. In 2017, Gulf reached the conclusion that SCRs would not be required for Plant Daniel at this time. The EPA's anticipated announcement classifying the ozone standard for Plant Daniel's Jackson county and adjacent counties as "attainment/unclassifiable" supports Gulf's conclusion.

Q. Please explain the O&M variance of ($63,364) or (17.7%) in the Crist Water Conservation (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. This variance is primarily due to Gulf being able to postpone some projected maintenance activities until 2018.

Q. Please explain the O&M variance of $(1,222,537) or (20%) in the Coal Combustion Residual, (Line item 1.23).

A. The CCR program includes O&M costs associated with the regulation of Coal Combustion Residuals by United States Environmental Protection Agency and the Florida Department of Environmental Protection. More specifically, the CCR program includes requirements to close the existing on-site ash pond at Plant Scholz, and regulates CCR units at Gulf's Plants Crist, Scherer, Smith and Daniel. The variance is primarily due to activities related to the Plant Smith CCR Wastewater Treatment Plant. Gulf originally planned to begin operating the system in September 2017; however, the project was delayed until 2018 to allow time to conduct additional geochemical modeling, to evaluate potential waste issues, and to allow time to competitively bid out the project.

Q. Please explain the O&M variance of ($56,550) or (25.2%) in the Smith Water Conservation (Line item 1.24).

The Smith Water Conservation line item includes general O&M expenses associated with the Plant Smith reclaimed water systems, such as piping, valve maintenance and pump replacements. This variance is primarily due to a lower than projected cost for mechanical integrity testing as well as reduced sampling, laboratory, and engineering oversight expenses.

Q. Mr. Markey, 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. 20180007-EI
Date of Filing: July 25, 2018

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. 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 and 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 2018. 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 2018 through December 2018 with the approved projected amounts.

A. As reflected in Mr. Boyett's Schedule 6E, the recoverable capital costs approved in the original projection total $174,046,561, as compared to the estimated true-up amount of $155,545,219. This difference results in a variance of $(18,501,342) or (10.6%). In his Estimated/Actual Testimony, Witness Boyett addresses the impact of the 2018 Tax Stipulation and Settlement Agreement on the total recoverable capital cost variance.

Q. Please explain the capital variance of ($538,937) or (19.8%) reflected in the Smith Water Conservation Program (Line Item 1.17).

A. This variance is primarily due to costs for the Plant Smith Reclaimed Water project being less than originally anticipated. Design and construction of the Underground Injection Control (UIC) wastewater treatment system and associated pump station was postponed due to delays in the Request for Qualifications (RFQ) process for the reclaimed water pipeline design for the piping between Bay County and Plant Smith. During 2017, Gulf planned to begin construction of the project in 2018; however, the work has been postponed to 2019.

Q. Please explain the capital variance of $(14,613,212) or (10.1%) reflected in the Air Quality Compliance Program (Line Item 1.26).

A. This line item variance is primarily due to a change in the federal tax rate, as discussed in Witness Boyett's testimony. Offsetting the change in tax rate are costs associated with the Plant Crist Groundwater Characterization and Remediation project that were not included in Gulf's 2018 ECRC Projection filing. On September 22, 2017, Gulf received a request from the Florida Department of Environmental Protection (FDEP) to develop a corrective action plan for elevated groundwater trends observed in the vicinity and downgradient of the Plant Crist gypsum storage area. Gulf submitted an Interim Remedial Action Plan to FDEP in November 2017 that proposed installing an active remediation system within 120 days of receiving FDEP approval. Gulf received FDEP approval in January 2018, and the remediation system is currently operational. The costs associated with the remediation system were not included in Gulf's 2018 Projection filing because Gulf had not received a request from FDEP to implement remedial activities at the time of the filing.

Q. Please explain the capital variance of ($899,512) or (88.0%) reflected in the Coal Combustion Residual (CCR) (Line Item 1.28).

A. The CCR line item variance is primarily due to delays associated with the Plant Scholz ash pond closure project. The closure schedule shifted as a result of contractor delays in procuring and installing the dewatering wastewater treatment system needed for excavation. The wastewater treatment system became fully operational in May 2018, and pond closure and excavation activities are currently on-going.

Q. How do the estimated/actual 2018 O&M expenses compare to the original 2018 projections?

A. Mr. Boyett's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are estimated at $38,737,706, as compared to the amount projected in the 2018 Projection filing of $43,750,497, which creates a variance of ($5,012,791) or (11.5%). I will address two O&M projects and programs that contribute to a significant portion of this variance: Air Quality Compliance Program and Coal Combustion Residual.

Q. Please explain the O&M variance of $1,146,850 or 5.2% 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 Selective Catalytic Reduction (SCR) and the Plant Daniel scrubbers, as well as Plant Scherer's baghouse, MATS emissions monitoring equipment, SCR, and scrubber. More specifically, this line item includes the cost of limestone and ammonia, along with general operation and maintenance activities included in Gulf's Air Quality Compliance Program. The line item variance is primarily due to repairs made to the Plant Crist gas cooling pumps on the scrubber during the 2018 spring outage. During the 2018 Crist scrubber outage, inspections of the pumps revealed the need for repairs that were not known at the time Gulf filed its projections in this docket.

Q. Please explain the variance of ($5,985,162) or (49.7%) 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 FDEP. For Gulf's generating plants, these regulatory compliance obligations are pursuant either to the CCR rule adopted last year or to permit requirements added by the State through the National Pollutant Discharge Elimination System (NPDES) permits issued for each of Gulf's generating facilities. Approximately $3.5 million of the variance is attributable to delays in the

Plant Scholz pond closure and associated wastewater treatment O&M costs. As discussed previously, the closure schedule shifted due to contractor delays in procuring and installing the dewatering wastewater treatment system. The wastewater treatment system became fully operational in May 2018, and pond excavation activities are currently on-going. Approximately $1.8 million of the variance is due to delays associated with procurement and installation of the Plant Smith dewatering wastewater treatment system and to the estimated monthly operational expense being less than originally anticipated. The Plant Smith system is scheduled to be placed in-service during July 2018.

Q. 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. 20180007-EI
Date of Filing: August 24, 2018

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

A. My name is Richard M. Markey. My business address is One Energy Place, Pensacola, Florida, 32520. I am employed by Gulf Power Company as the Director of Environmental Affairs.

Q. Have you previously filed testimony in this docket?

A. Yes, I have.

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 2019 through December 2019.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?

A. Yes, I have prepared 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) includes the 316(b) Cooling Water Intake Structure Regulation.

Counsel: We ask that Mr. Markey's exhibits be marked as Exhibit No. _____ (RMM-1) and 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 listed in Schedules 3P and 4P of Gulf Witness Boyett's Exhibit CSB-3 and described in 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, one is a new program that Gulf is proposing and nine programs were previously approved by the Commission which have activities with projected capital expenditures during 2019. These programs include: Air Quality Assurance Testing, Continuous Emission Monitoring Systems (CEMS), Substation Contamination Remediation, Smith Water Conservation, Crist Florida Department of Environmental Protection (FDEP) Agreement for Ozone Compliance, Crist Water Conservation, Air Quality Compliance Program, Coal Combustion Residuals, and Effluent Limitations Guidelines.

Q. Mr. Markey, please describe the new capital program Gulf seeks to recover through the ECRC.

A. Gulf is including one new Water Quality program, the 316(b) Cooling Water Intake Structure project, in addition to the programs previously approved by the Commission.

Q. Mr. Markey, please describe the 316(b) Cooling Water Intake Structure program that Gulf seeks to recover through the ECRC (Line Item 1.30).

A. On August 15, 2014, the EPA published final regulations under Section 316(b) of the Clean Water Act for cooling water intake structures at existing electric generating facilities. The rule, found in Title 40 Parts 122 and 125 of the Code of Federal Regulations, (See Exhibit RMM-2), became effective on October 14, 2014, requiring existing facilities withdrawing greater than 2 million gallons per day (MGD) to adopt one of seven options for addressing impingement at the entrance to existing cooling water intake structures. Although the ultimate 316(b) compliance strategy and design will be approved by the state environmental permitting agencies, with possible input from the U.S. Fish and Wildlife Service and National Marine Fisheries Service (Services) and EPA, Gulf Power's preliminary studies indicate Plant Smith will need to install new lower capacity intake pumps and a closed-cycle cooling tower monitoring system for the existing Unit 3 closed-cycle cooling tower.

The lower capacity pumps are needed to reduce the intake maximum through-screen velocity to less than 0.5 foot per second to meet the 316(b) impingement performance standard. Gulf plans to install the new lower capacity intake pumps at Plant Smith during 2019. The Plant Smith industrial wastewater permit requires Gulf to submit information required under the Cooling Water Intake Structure 316(b) rule with its next permit renewal, due in April 2019 for FDEP review and approval. The projected 2019 expenditures for this line item total $2,000,000.

Q. Mr. Markey, please describe the projected 2019 capital expenditures for Air Quality Assurance Testing (Line Item 1.1).

A. Gulf plans to replace the existing analyzers located in the Gulf Power test trailer during 2019. The existing analyzers are used for Relative Accuracy Test Audits (RATAs) and other testing at various Gulf locations. The analyzers are at the end of the normal useful life, and the manufacturer no longer provides spare parts. Expenditures associated with this equipment reflected in the 2019 projection filing are $65,000.

Q. Mr. Markey, please describe the projected 2019 capital expenditures for Continuous Emission Monitoring Systems (CEMS) (Line Item 1.5).

A. Gulf plans to replace the existing Plant Crist CEMS monitors located in the scrubber stack during 2019. The existing monitors are at the end of the normal life cycle and need to be replaced. Expenditures associated with these activities reflected in the 2019 projection filing are $200,000.

Q. Mr. Markey, please describe the projected 2019 capital expenditures for Substation Contamination Remediation (Line Item 1.6).

A. During 2019, Gulf plans to complete construction of the Fort Walton and Wewa substation remediation systems. The existing remediation equipment at the Fort Walton substation was installed in 1998 and needs to be replaced. Gulf is currently in the process of designing an active remediation system for the Wewa substation site. Site geological and geochemical data indicate installing a permeable reactive barrier (PRB) is the best option to decrease groundwater concentrations at the Wewa site. Expenditures associated with these activities reflected in the 2019 projection filing total $1,496,496.

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

A. Gulf was granted approval for ECRC recovery of the Plant Smith Reclaimed Water project in Florida Public Service Commission (FPSC) Order No. PSC-09-0759-FOF-EI. Gulf has installed three deep injection wells, piping, and initial equipment needed for the reclaimed water pump station. Design and construction of the Underground Injection Control (UIC) wastewater treatment system and associated pump station were postponed in 2018 due to delays in the Request for Qualifications (RFQ) process for the reclaimed water pipeline design for the piping between Bay County and Plant Smith. Gulf plans to complete design and begin construction of the system needed for reclaimed water in 2019. Expenditures associated with these activities reflected in the 2019 projection filing are $13,033,532.

While Gulf is in the process of completing design and construction of the reclaimed water system, the Smith UIC system will be used for treatment and injection of wastewater from the Plant Smith ash pond closure project.

Q. Mr. Markey, please describe the projects included in the 2019 projection for the Crist FDEP Agreement for Ozone Attainment (Line Item 1.19).

A. Gulf plans to replace catalyst in the Plant Crist Unit 7 SCR during 2020. The catalyst NOx removal effectiveness is declining at a normal rate and indicates the catalyst will need to be replaced during a 2020 outage. The projected 2019 expenditure is for a catalyst progress payment totaling $200,000.

Q. Please describe the projected capital expenditures for the Crist Water Conservation program (Line Item 1.24).

A. The Crist Water Conservation program is part of Gulf's water conservation and consumptive use efficiency program required by the Plant Crist consumptive water use permit. Plant Crist's consumptive use permit, issued by the Northwest Florida Water Management District (NWFWMD), requires the plant to implement measures to increase water conservation and efficiency at the facility. The 2019 projected expenditures for the Crist Water Conservation program are for the replacement of pumps, valves and motors. The projected 2019 expenditures for this line item total $100,000.

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

A. The 2019 projected expenditures for the Air Quality Compliance program include costs associated with the following: Plant Crist and Plant Daniel scrubbers, Plant Crist Unit 6 SCR, and the Plant Daniel Low NOx burners. More specifically, this line item includes expenditures for the Plant Crist gypsum storage area, gas cooling nozzles, scrubber agitator gear box, Unit 6 SCR catalyst layer, elevator, and air compressors. Approximately $6.2 million is projected for expansion of the Plant Crist UIC pump station. The expansion will allow Plant Crist to utilize two additional wells for disposal of wastewater generated from the gypsum storage facility and associated groundwater remediation system. Plant Crist will also be constructing a new limestone system that will add limestone as needed to the coal to help maintain the performance of catalyst used in the SCRs. The cost of the new limestone system is projected to be approximately $1 million. During 2019, Gulf will be making a progress payment of $500,000 for a new scrubber alignment grid at Plant Crist that will be installed in the 2020 scrubber outage. Plant Daniel will also be replacing the low NOx burners on Unit 2, which have reached the end of their useful life. The cost of the new low NOx burners is approximately $490,000. The projected 2019 expenditures for this program total $8,660,145.

Q. Mr. Markey, please describe the projects included in Gulf's 2019 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 FDEP. For Gulf's generating plants, these regulatory compliance obligations are pursuant either to the CCR rule adopted in April 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. Plant Scherer is also regulated under Georgia's Environmental Protection Division CCR Rule (391-3-4-.10), which requires permit applications to be submitted for the facility's ash pond and CCR landfill by November 22, 2019. The projected 2019 expenditures for this line item total $50.8 million, which includes costs for Plants Scholz, Smith, Scherer and Daniel as discussed below.

Construction activities for closure of the ash pond at Plant Scholz have begun. During 2019, the Scholz ash pond closure project will include constructing a new stormwater management system, transferring CCR material to a dry stack area within the footprint of the pond, and capping the dry stack area with closure turf material. The 2019 expenditures for the Plant Scholz CCR closure are projected to be $7.1 million.

Earlier this year at Plant Smith, Gulf began construction of a new industrial wastewater treatment pond by relocating CCR material within the ash pond footprint. In 2019, Gulf will proceed with constructing new industrial wastewater ponds and a slurry wall, as well as transferring CCR material to a dry stack area within the footprint of the pond. The 2019 expenditures for the Plant Smith CCR closure are projected to be $22.5 million.

The Plant Scherer ash pond is scheduled to stop receiving coal ash in 2019. Engineering and construction work necessary to accommodate dry ash handling is expected to be completed in 2019. Design and construction of the Scherer CCR wastewater management system will continue in 2019. In addition, detailed engineering and construction will continue at Cell 3 of the onsite landfill for CCR storage. Plant Scherer will also proceed with siting studies and preliminary design for a new landfill. The 2019 expenditures for the Plant Scherer CCR projects are projected to be $9.2 million.

The Plant Daniel bottom ash pond closure is projected to begin in the 2021 timeframe and is expected to take approximately three years to complete. Prior to beginning closure activities, the plant will need to construct a new wastewater treatment and ash handling system. Plant Daniel is currently in the process of completing studies to determine the most cost-effective technologies and system design. Plant Daniel will need to reroute wastewater streams from the ash pond to a new wastewater system prior to beginning closure of the bottom ash pond in 2021. The 2019 expenditures for the Plant Daniel CCR projects are projected to be $12.0 million.

Q. Mr. Markey, please describe the projects included in Gulf's 2019 projection for the Effluent Limitations Guideline capital program (Line Item 1.29).

A. In 2015, the EPA finalized revisions to the steam electric effluent limitations guidelines (ELG) rule, which imposes stringent technology-based requirements for certain waste streams from steam electric generating units. The revised technology-based limits and compliance dates will require extensive modifications to existing ash and flue gas desulfurization (FGD) scrubber wastewater management systems or the installation and operation of new wastewater management systems. Compliance applicability dates in the 2015 rule ranged from November 1, 2018, to December 31, 2023.

On September 18, 2017, EPA published a final rule in the Federal Register that delayed the earliest ELG applicability date for FGD wastewater and bottom ash transport water from the original (2015 rule) "as soon as possible date" of November 1, 2018, to a new "as soon as possible" date of November 1, 2020, to allow time for EPA to reconsider the requirements for FGD wastewater and bottom ash transport water. The 2017 rule did not change the latest applicability date or "no later than" date of December 31, 2023.

State environmental agencies will incorporate specific applicability dates in the NPDES permitting process based on information provided for each waste stream. The EPA plans to propose ELG rule revisions in December 2018 and to finalize the rulemaking in December 2019. Gulf has projected costs in 2019 for engineering and design of Gulf's ownership portion of the

Scherer scrubber wastewater treatment system. The 2019 expenditures for this line item total $456,695.

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.

Q. Please describe the O&M activities included in the air quality category for 2019.

A. There are five O&M activities included in the air quality category that have projected expenses in 2019. The five activities are: Air Emission Fees, Title V, Asbestos Fee, Emissions Monitoring, and the FDEP NOx Reduction Agreement.

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 total 2019 estimated expenses for the Air Emission Fees are $305,099.

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 2019 estimated expenses for the Title V program are $293,254.

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 total 2019 estimated expenses for the Asbestos Fees are $1,000.

Emission Monitoring (Line Item 1.5) on Schedule 2P reflects an ongoing O&M expense associated with the CEMS 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 total 2019 estimated expenses for the Emissions Monitoring are $739,036.

The FDEP NOx Reduction Agreement (Line Item 1.19) is comprised of 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 total 2019 estimated expenses for the FDEP NOx Reduction Agreement are $1,021,274.

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 NPDES industrial wastewater permit compliance, Groundwater Monitoring and Assessment, Surface Water Studies, the Cooling Water Intake Program, Soil Contamination Studies, Dechlorination, the Impoundment Integrity Program, and Stormwater Maintenance. The total 2019 estimated expenses for General Water Quality are $2,014,654.

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 FPSC Docket No. 930613-EI. This line item includes expenses related to substation investigation and remediation activities. Gulf has projected $2,825,274 of incremental expenses for this line item during the 2019 recovery period.

Line Item 1.8, State 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 $42,000 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 estimated to be $4,000 during the 2019 projection period. Line Item 1.23, is the CCR program that includes expenses related to the regulation of Coal Combustion Residuals by the EPA and the FDEP. During 2019, 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 2019 expenses projected for the CCR line item total $3,229,639, which encompasses Plant Scholz and Plant Smith pond closure activities.

As mentioned previously, construction activities for closure of the ash pond at Plant Scholz have begun. During 2019, the Scholz ash pond closure project will include constructing a new stormwater management system, transferring CCR material upland to a dry stack area within the footprint of the pond, and capping the dry stack area with closure turf material. The 2019 expenses for the Plant Scholz CCR closure are projected to be $1.5 million.

Earlier this year at Plant Smith, Gulf began construction of a new industrial wastewater treatment pond by relocating CCR material within the ash pond footprint. In 2019, Gulf will proceed with construction and associated activities to close a portion of the pond. The 2019 pond closure activities will include constructing industrial wastewater ponds and a slurry wall, as well as transferring CCR material upland to a dry stack area within the footprint of the pond. The 2019 expenses associated with the Plant Smith CCR closure are projected to be $1 million.

Q. What activities are included in the environmental affairs administration category?

A. Only one O&M activity is included in this category on Schedule 2P (Line Item 1.10) of Mr. Boyett's Exhibit CSB-3. This line item refers to the Company's Environmental Audit/Assessment function. This program is an on-going compliance activity previously approved for ECRC recovery. The total 2019 estimated expenses for the Environmental Audit/Assessment are $15,000.

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. The total 2019 estimated expenses for the General Solid and Hazardous Waste activity is $1 million.

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 2019. They are the Above Ground Storage Tanks program, the Sodium Injection System, the Air Quality Compliance Program, Crist Water Conservation, Smith Water Conservation, and Emission Allowances.

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

A. Above Ground Storage Tanks (Line Item 1.12) includes maintenance activities, tank integrity inspections, and fees required by Florida's above ground storage tank regulation, Chapter 62 Part 762, F.A.C. Expenses totaling $92,532 are projected to be incurred during 2019.

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 $10,000 are projected to be incurred during 2019 for this line item.

Q. What activities are included in the Air Quality Compliance Program (Line Item 1.20)?

A. This line item encompasses 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. Anhydrous ammonia, hydrated lime, limestone and general O&M expenses are included in the Air Quality Compliance Program line item. The projected cost for limestone associated with operation of the Plant Crist, Plant Daniel, and Plant Scherer 3 scrubbers is approximately $9.2 million. The projected 2019 expenses for this line item total $21,813,790.

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 and valve maintenance. Expenses totaling $428,542 are projected to be incurred during 2019 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 was 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 the FDEP permit. Gulf was granted approval for recovery of the Plant Smith Reclaimed Water project in FPSC Order No. PSC-09-0759-FOF-EI. Expenses totaling $190,000 are projected to be incurred during 2019 for this line item.

Q. Please describe the emission allowance expense line items.

A. This line item includes projected allowance expenses for Gulf's generation. Line Item 1.26 includes $7,214 of projected expenses for annual NOx allowances, Line Item 1.27 includes $7,887 of projected expenses for seasonal NOx allowances, and Line Item 1.28 includes $37,762 of projected expenses for SO_2 allowances during 2019.

Q. Do each of the capital projects and O&M activities that have projected costs in 2019 meet the ECRC statutory guidelines?

A. Yes. The projects included in Gulf's 2019 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 includes 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
Prepared Direct Testimony
C. Shane Boyett
Docket No. 20180007-EI
Date of Filing: April 2, 2018

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 Regulatory and Cost Recovery Manager for Gulf Power Company (Gulf or the Company).

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

A. I graduated from the University of Florida in 2001 with a Bachelor of Science degree in Business Administration and earned a Master of Business Administration degree from the University of West Florida in 2005. I joined Gulf Power in 2002 and worked five years as a Forecasting Specialist until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. I transferred to Gulf Power's Financial Planning department in 2014 as a Financial Analyst until being promoted to lead the Regulatory and Cost Recovery department later that year. My current responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of Gulf Power Company.

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 2017 through December 2017 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 am sponsoring one exhibit. My exhibit consists of ten schedules, which are nine environmental cost recovery final true-up schedules and one schedule which contains the Scherer/Flint credit calculation, as described later in my testimony. This exhibit was prepared under my direction, supervision, and review.

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

Q. Are you familiar with the ECRC true-up calculation for the period January through December 2017 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, I have. Unless otherwise indicated, the actual data in these documents is taken from the books and records of Gulf Power Company. 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 the Florida Public Service Commission (FPSC or Commission).

Q. What is the final ECRC true-up amount for the period ending December 31, 2017, to be addressed in the recovery period beginning January 2019?

A. An over-recovery in the amount of $3,179,666 was calculated and is reflected on line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $3,179,666 over-recovery was calculated by taking the difference between the estimated January 2017 through December 2017 over-recovery of $11,475,260 as approved in FPSC Order No. PSC-2018-0014-FOF-EI, dated January 5, 2018, and the actual over-recovery of $14,654,926 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 2017 through December 2017. 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 2017 through December 2017 with the estimated/actual O&M expenses as filed on August 4, 2017, in Docket No. 20170007-EI. Schedule 5A shows the monthly O&M expenses by activity, including the offsetting Scherer/Flint credit 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 Gulf Witness Markey's final true-up testimony.

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

A. Schedule 6A for the period January 2017 through December 2017 compares the actual recoverable costs related to investment with the estimated/actual amount as filed on August 4, 2017, in Docket No. 20170007-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 recovery period. Recoverable costs also include a return on working capital associated with emission allowances and the regulatory asset associated with the retirement of Smith Units 1 and 2 established by Commission Order No. PSC-16-0361-PAA-EI in Docket No. 20160039-EI dated August 29, 2016. Schedule 7A provides the monthly recoverable costs associated with each project, including the offsetting Scherer/Flint credit along with the calculation of the jurisdictional recoverable costs.

Any material variances in recoverable costs related to the environmental investment for this period are discussed in Mr. Markey's final true-up testimony.

Q. Please describe Schedule 8A of your exhibit.

A. Schedule 8A includes 34 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, cost of emission allowances and the regulatory asset. Pages 1 through 29 of Schedule 8A show the investment and associated costs related to capital projects, while pages 30 through 33 show the investment and costs related to emission allowances, and page 34 shows the costs related to the regulatory asset for retired Plant Smith Units 1 and 2.

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. 20120007-EI, the capital structure used in calculating the rate of return for recovery clause purposes for January 2017 through March 2017 is based on the weighted average cost of capital (WACC) presented in Gulf's May 2016 Earnings Surveillance Report. For April 2017 through December 2017, the rate of return used is the WACC established by specific terms in the Stipulation and Settlement

Agreement approved by the Commission in Order No. PSC-17-0178-S-EI in consolidated Dockets Nos. 20160186-EI and 20160170-EI dated May 16, 2017 (2017 Settlement Agreement). The WACC for both periods includes a return on equity of 10.25% as reflected on Schedule 9A.

Q. Please describe Schedule 10A.

A. Schedule 10A provides the monthly calculation of the total ECRC revenue requirements of Gulf's ownership in Scherer Unit 3 (Scherer 3) and quantifies the portion of Scherer 3 incremental revenue requirements that continues to be committed to a wholesale customer through a long-term contract (Scherer/Flint credit), which will expire December 2019. In accordance with the provisions of the 2017 Settlement Agreement, Gulf is including the Scherer/Flint credit as an offset to recoverable O&M and capital investment costs until Scherer 3 is no longer partially committed to the wholesale customer. The Scherer/Flint credits appear on Lines 1.29 and 1.30 of Schedules 4A and 5A, and on Lines 1.35 and 1.36 of Schedules 6A and 7A of my Exhibit CSB-1. The inclusion of the Scherer/Flint credit, as calculated, results in ECRC being revenue-neutral regarding the incremental portion of Scherer 3 investment and expenses.

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

A. Yes

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony
C. Shane Boyett
Docket No. 20180007-EI
Date of Filing: July 25, 2018

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 Regulatory and Cost Recovery Manager for Gulf Power Company. (Gulf or the Company)

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

A. I graduated from the University of Florida in 2001 with a Bachelor of Science degree in Business Administration and earned a Master of Business Administration from the University of West Florida in 2005. I joined Gulf Power in 2002 as a Forecasting Specialist until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. I transferred to Gulf Power's Financial Planning department in 2014 as a Financial Analyst until being promoted to lead the Regulatory and Cost Recovery department later that year. My current responsibilities include supervision of tariff administration, calculation of cost recovery factors, and the regulatory filing function of Gulf Power Company.

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 2018 through December 2018 for the Environmental Cost Recovery Clause (ECRC).

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?

A. Yes, I am sponsoring one exhibit. My exhibit consists of ten schedules, nine of which are environmental cost recovery estimated true-up schedules and one of which contains the Scherer/Flint credit calculation, as defined later in my testimony. This exhibit was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibit consisting of ten 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. Unless otherwise indicated, the actual data in these documents is taken from the books and records of Gulf Power Company. 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 the FPSC.

Q. What has Gulf calculated as the estimated true-up for the January 2018 through December 2018 period to be addressed in 2019 ECRC factors?

A. The estimated true-up for the current period is an over-recovery of $9,436,937 as shown on Schedule 1E of Exhibit CSB-2. This amount is based on six months of actual data and six months of estimated data. It will be added to the 2017 final true-up over-recovery amount of $3,179,666. The total true-up over-recovery of $12,616,603 will be addressed in Gulf's proposed 2019 ECRC factors. The detailed calculations supporting the estimated true-up for 2018 are contained in Schedules 2E through 10E of Exhibit CSB-2.

Q. Does the estimated true-up amount discussed above reflect the provisions of the 2018 Tax Stipulation and Settlement Agreement (2018 Tax Settlement Agreement)?

A. Yes. The schedules contained in my exhibit reflect the ECRC-related provisions of the 2018 Tax Settlement Agreement, which include lower ECRC rates effective April 2018, lower cost of capital as a result of the federal income tax rate change, and capital structure adjustments. The 2018 Tax Settlement Agreement was approved by Florida Public Service Commission (FPSC or Commission) Order No. PSC-2018-0180-FOF-EI in Docket No. 20180039-EI, dated April 12, 2018. The implementation of the 2018 Tax Settlement Agreement provisions account for approximately $17.6 million of the total recoverable capital cost variance.

Q. Please describe Schedules 2E and 3E of your Exhibit CSB-2.

A. Schedule 2E shows the calculation of the estimated over-recovery of environmental costs for the period January 2018 through December 2018. Schedule 3E of this exhibit is the calculation of the interest provision on the average true-up balance. This same method of calculating interest is used in the Fuel Cost Recovery and Purchased Power Capacity Cost Recovery clauses.

Q. Please describe Schedules 4E and 5E of your Exhibit CSB-2.

A. Schedule 4E compares the estimated/actual O&M expenses for the period January 2018 through December 2018 to the projected O&M expenses approved by the Commission in Docket No. 20170007-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. Gulf Witness Markey describes the reasons for the expected variances in O&M expenses in his estimated/actual testimony.

Q. Please describe Schedules 6E and 7E of your Exhibit CSB-2.

A. Schedule 6E for the period January 2018 through December 2018 compares the estimated/actual investment-related recoverable costs to the projected amount approved in Docket No. 20180007-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 and a return on the unamortized balance of the regulatory asset associated with the retirement of Smith Units 1 and 2 established by Commission Order No. PSC-2016-0361-PAA-EI in Docket No. 20160039-EI, dated August 29, 2016. Mr. Markey discusses variances in recoverable capital costs related to environmental project activities in his estimated/actual testimony. Schedule 7E provides the monthly recoverable revenue requirements associated with each project, along with the calculation of the jurisdictional recoverable revenue requirements.

Q. Please describe Schedule 8E of your Exhibit CSB-2.

A. Schedule 8E includes 34 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, return on working capital associated with emission allowances and return on unamortized balance of the Smith 1 and 2 regulatory asset. 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, and page 34 shows the costs related to the regulatory asset for retired Plant Smith Units 1 and 2.

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 of Exhibit CSB-2?

A. The capital structure used in calculating the rate of return for recovery clause purposes for January 2018 through June 2018 is based on the weighted average cost of capital (WACC) established by the 2018 Tax Settlement Agreement. For July 2018 through December 2018, Gulf utilized the capital structure and rate of return presented in its May 2018 Earnings Surveillance Report, as adjusted per the terms of the 2018 Tax Settlement Agreement. The WACC for both periods includes a return on equity of 10.25 percent, a federal income tax rate of 21 percent and is consistent with Commission Order No. PSC-2012-0425-PAA-EU dated August 16, 2012, in Docket No. 20120007-EI.

Q. Please describe Schedule 10E of your exhibit.

A. Schedule 10E provides the monthly calculation of the total ECRC revenue requirements of Gulf's ownership in Plant Scherer Unit 3 (Scherer 3) and quantifies the incremental portion of Scherer 3 environmental revenue requirements that continues to be committed to a wholesale customer through a long-term contract (Scherer/Flint credit), which will expire December 2019. In accordance with the provisions of the Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-2017-0178-S-EI in consolidated Docket Nos. 20160186-EI and 2016170-EI dated May 16, 2017, Gulf is including the Scherer/Flint credit as an offset to recoverable O&M and capital investment costs until Scherer 3 is no longer partially committed to the wholesale customer. The Scherer/Flint credits appear on Lines 1.29 and 1.30 of Schedules 4E and 5E, as well as on Lines 1.35 and 1.36 of Schedules 6E and 7E, of my Exhibit CSB-2. The inclusion of the Scherer/Flint credit, as calculated, results in ECRC being revenue-neutral regarding the incremental portion of Scherer 3 investment and expenses.

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

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. Shane Boyett
Docket No. 20180007-EI
Date of Filing: August 24, 2018

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 Regulatory and Cost Recovery Manager for Gulf Power Company.

Q. Have you previously filed testimony in this docket?

A. Yes.

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 January 2019 through December 2019.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?

A. Yes, I am sponsoring one exhibit. My exhibit consists of ten schedules, nine of which are Gulf's environmental cost recovery projection schedules and one of which contains the calculation of the Scherer/Flint credit. This exhibit was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibit 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 Florida Public Service Commission (FPSC or Commission) in Order No. PSC-94-0044-FOF-EI in Docket No. 930613-EI and with past proceedings in this ongoing recovery docket. The costs identified for recovery through the ECRC are not currently being recovered through base rates or any other cost recovery mechanism.

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

A. Mr. Markey has provided projected recoverable O&M expenses for January 2019 through December 2019. 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.

Q. Please describe Schedules 3P and 4P of your Exhibit CSB-3.

A. Schedule 3P summarizes the monthly recoverable revenue requirements associated with each capital investment program for the recovery period. Schedule 4P shows the detailed calculation of the revenue requirements associated with each investment program. Schedules 3P and 4P also include the calculation of the jurisdictional amount of recoverable revenue requirements. 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, 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. 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 2018 Surveillance Report, as adjusted per the terms of the 2018 Tax Settlement and Stipulation Agreement, approved by FPSC Order No. PSC-2018-0180-FOF-EI in Docket No. 20180039-EI, dated April 12, 2018. The rate of return used to calculate ECRC revenue requirements includes a return on equity of 10.25 percent for the period January 1, 2019, through December 31, 2019, a federal income tax rate of 21 percent and is consistent with Commission Order No. PSC-12-0425-PAA-EU dated August 16, 2012, in Docket No. 120007-EI.

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

Q. What is the total amount of projected recoverable costs related to the period January 2019 through December 2019?

A. The total projected jurisdictional recoverable costs for the period January 2019 through December 2019 is $184,156,532 as shown on line 1c of Schedule 1P of Exhibit CSB-3. This amount includes costs related to O&M activities of $32,665,945 and costs related to capital projects of $151,490,587, as shown on lines 1a and 1b of Schedule 1P. The adjustment (Scherer/Flint credit) as reflected on Lines 1.29 and 1.30 of Schedule 2P and Lines 1.36 and 1.37 of Schedule 3P represents the incremental revenue requirement related to the portion of Scherer Unit 3 (Scherer 3) that continues to be committed to a wholesale customer through a long-term contact. The Scherer/Flint credit is calculated in accordance with the provisions in the Stipulation and Settlement Agreement, FPSC Order No. PSC-17-0178-S-EI, resulting in ECRC being revenue-neutral regarding the incremental inclusion of Scherer 3 investment and expenses.

Q. What is the total recoverable revenue requirement to be recovered in the projection period January 2019 through December 2019, and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $171,663,438 for the period January 2019 through December 2019, 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 $12,616,603. 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 Schedule 6P and 7P of Exhibit CSB-3.

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

A. The demand allocation factors used in the ECRC have been 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. and adjusted for losses. 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 A through G 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 $32,401,985 for the period January 2019 through December 2019 was allocated using the energy allocator, as shown in column C on Schedule 7P of Exhibit CSB-3. The demand-related recoverable revenue requirement of $139,261,453 for the period January 2019 through December 2019 was allocated using the demand allocator, as shown in column D 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 E 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 $18.10 monthly for the period January 2019 through December 2019.

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 2019 and will continue through the last billing cycle of December 2019.

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

A. Yes.

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court 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 7th day of November, 2018.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #GG015952
EXPIRES JULY 27, 2020