BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of: DOCKET NO. 120007-EI

ENVIRONMENTAL COST RECOVERY CLAUSE.
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PROCEEDINGS: HEARING

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

DATE: Monday, November 5, 2012

TIME: Commenced at 9:30 a.m.
Concluded at 9:51 a.m.

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

REPORTED BY: JANE FAUROT, RPR
Official FPSC Reporter
(850) 413-6732

APPEARANCES:

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

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

JAMES W. BREW, ESQUIRE and F. ALVIN TAYLOR, ESQUIRE, c/o Brickfield Law Firm, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington D.C., 20007, appearing on behalf of White Springs Agricultural Chemicals, Inc.

MAJOR CHRISTOPHER THOMPSON, Federal Executive Agencies, c/o USAF/AFLOA/JACL/ULFSC, 139 Barnes Drive, Suite 1, Tyndall AFB, Florida 32403-5319, appearing on behalf of Federal Executive Agencies.

JON C. MOYLE, JR., ESQUIRE, Moyle Law Firm, 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

APPEARANCES (Continued):

JOHN T. BUTLER, ESQUIRE, and KEN RUBIN, ESQUIRE, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

GARY V. PERKO, ESQUIRE, Hopping Law Firm, Post Office Box 6526, Tallahassee, Florida 32314, appearing on behalf Progress Energy Florida, Inc. and Progress Energy Service Company.

CHARLES REHWINKEL, ESQUIRE, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison St., Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of Florida.

JOHN T. BURNETT, ESQUIRE and DIANNE M. TRIPLETT, ESQUIRE, Progress Energy Service Company, LLC, Post Office Box 14042, St. Petersburg, Florida 33733-4042, appearing on behalf of Progress Energy Florida, Inc.

APPEARANCES (continued):

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

SAMANTHA CIBULA, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.
1-37	12	12

P R O C E E D I N G S

CHAIRMAN BRISÉ: Good morning. We're going to go ahead and call this hearing to order, and I'll request that our staff read the notice.

MS. BROWN: By notice issued September 18th, 2012, this time and place was set for a hearing in the following dockets; Docket Number 120001-EI, Docket Number 120002-EG, Docket Number 120003-GU, Docket Number 120004-GU, Docket Number 120007-EI. The purpose of the hearing is set forth in the notice.

CHAIRMAN BRISÉ: Thank you.

At this time we're going to go ahead and take appearances. There are five dockets to address today. Staff suggests that all appearances be taken at once, so we will do so. All parties should enter their appearance and declare the dockets that they are entering an appearance for. So we will go through the process with everyone from the parties, and then as usual, we'll take appearances from our staff.

Okay. I guess we'll start from my left, your right.

MR. BUTLER: Thank you, Mr. Chairman.

John Butler and Ken Rubin appearing on behalf of Florida Power and Light Company in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Thank you.

MS. TRIPLETT: Good morning, Commissioners.

Diane Triplett and John Burnett appearing on behalf of Progress Energy Florida in the 01, 02, and 07 dockets, and I would also like to enter an appearance for Gary Perko in the 07 docket.

CHAIRMAN BRISÉ: Thank you.

MR. BADDERS: Good morning, Commissioners.

Russell Badders appearing on behalf of Gulf Power in the 01, 02, and 07 dockets. I would also like to enter an appearance for Jeffrey A. Stone and Steven R. Griffin in the same dockets.

CHAIRMAN BRISÉ: Thank you.

MR. BEASLEY: Good morning, Commissioners. Jim Beasley and Jeff Wahlen for Tampa Electric Company in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: All right.

MS. KEATING: Good morning, Commissioners. Beth Keating with the Gunster law firm appearing today on behalf of FPUC in the 01, 02, and 03 dockets, as well as Florida City Gas in the 03 docket; and Florida City Gas, Chesapeake, FPUC, and Indiantown in the 04 docket.

CHAIRMAN BRISÉ: Thank you.

MR. MOYLE: Good morning. Jon Moyle on behalf of the Florida Industrial Power Users Group. I'm with the Moyle law firm, and we are appearing in the 01, 02, and 07 dockets.

MR. BREW: Good morning, Mr. Chairman, Commissioners. I'm James Brew with the firm of Brickfield, Burchette, Ritts & Stone. I'm here for White Springs Agricultural Chemicals, PCS Phosphate, in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Thank you.

MR. REHWINKEL: Good morning, Commissioners. Charles Rehwinkel, Office of Public Counsel. I am appearing in the 01 and 07 dockets.

MS. CHRISTENSEN: Patty Christensen with the Office of Public Counsel. I'm appearing in the 01, 02, 03, 04, and 07 dockets. And I would also like to put in an appearance for Joe McGlothlin in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Thank you.

MR. WRIGHT: Good morning, Mr. Chairman, Commissioners. Robert Scheffel Wright and John T. LaVia, III, appearing in the fuel docket, 120001, on behalf of the Florida Retail Federation.

MAJOR THOMPSON: Good morning, Commissioners. For FEA, it's Major Chris Thompson appearing in 01, 02, and 07.

CHAIRMAN BRISÉ: Okay. Thank you.

MS. BROWN: Good morning, Commissioners. Martha Brown and Michael Lawson appearing in the 03 docket.

CHAIRMAN BRISÉ: Thank you.

MS. ROBINSON: Pauline Robinson appearing in the 04 docket.

MS. TAN: Lee Eng Tan appearing for the 02 docket.

MS. BARRERA: Martha Barrera appearing, thankfully, on the 01 docket along with Lisa Bennett.

CHAIRMAN BRISÉ: Okay.

MS. CIBULA: Samantha Cibula, Advisor to the Commission in all dockets.

CHAIRMAN BRISÉ: Okay. Thank you.

MR. MURPHY: Charles Murphy in the 07 docket.

CHAIRMAN BRISÉ: All right. Thank you.

Is that everyone that needs to make an appearance this morning? Okay.

For the record, there are some companies that have asked to be excused from the hearing: St. Joe Natural Gas in Docket 03 and 04, Peoples Gas System, 03 and 04, and Southern Alliance for Clean Energy in Docket 02.

Okay. The order of the dockets that we are going to -- the order that we're going to take up the dockets is the 03 docket, 04 docket, 02 docket, 07, and then 01.

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CHAIRMAN BRISÉ: And now we'll proceed to Docket Number 120007-EI. So we open that docket. Are there any preliminary matters?

MR. MURPHY: There are proposed stipulations on all issues with intervenors taking no positions. All witnesses have been excused, and the parties have waived opening statements.

CHAIRMAN BRISÉ: All right. Thank you. Is there any prefiled testimony?

MR. MURPHY: Yes, sir. Staff asks that the prefiled testimony of all witnesses be inserted into the record as though read. These are identified at Section VI of the Prehearing Order, Pages 4 and 5.

CHAIRMAN BRISÉ: All right. If there are no objections, we will enter the prefiled testimony into the record as though read.

Okay. Exhibits.

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

CHAIRMAN BRISÉ: Okay. At this point we will move all exhibits into the record as put together for the Comprehensive Exhibit List. Any objections? Okay.

MR. MURPHY: Staff moves Exhibits 1 through 37 into the record as set forth in the list.

CHAIRMAN BRISÉ: All right. We will move into the record 1 through 37.

(Exhibit Numbers 1 through 37 marked for identification and admitted into the record.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ROXANE R. KENNEDY

DOCKET NO. 120007-EI

April 2, 2012

Q. Please state your name and business address.

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

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Vice President of Power Generation Operations.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for the overall management and direction of the non-nuclear power plants for the Company. FPL's fleet consists of more than 20,000 megawatts ("MW") of electric-generating capability including traditional fossil-fuel-fired steam boilers, combined cycle, aero-derivative, and large-frame, simple-cycle combustion turbine ("CT") technologies and solar technologies.

Q Please describe your educational background and professional experience.

A. My professional background with FPL involves technical, managerial and commercial experience in progressively more demanding assignments over 25 years. I received a bachelor's degree in chemical engineering from the University of Florida in 1985. I am a registered professional engineer in Florida and have held my license for more than 14 years. Between 1985 and 2008, I held various staff, technical, maintenance, operating and business management roles at several FPL and NextEra Energy Resources' sites. In March 2009, I became the FPL Power Generation Division ("PGD") Director, and, subsequently, Vice President of Production Assurance and Business Services where I was responsible for providing production standardization and commercial management of PGD's generating fleet. In January 2010, I assumed my current position as Vice President of FPL's Power Generation Operations, overseeing more than 700 employees.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the initial year of operation at the Martin Next Generation Solar Energy Center ("Martin Solar"). I will address the challenges we faced as we integrated this first-of-a-kind, renewable-energy facility into our fleet, including the heat-transfer fluid ("HTF") release incident that occurred on June 1, 2011. I will also discuss the lessons learned and countermeasures that FPL implemented to prevent recurrence and to help ensure that Martin Solar can reach its full potential. Finally, I will address the Martin Solar HTF release's remediation costs of $2,233,412 that are the primary driver of the $2,319,416 Environmental Cost Recovery Clause ("ECRC") 2011 O&M variance.

Q. Does Martin Solar employ new solar technology?

A. Yes. Martin Solar began commercial operation on December 10, 2010. It provides 75 MW of solar-thermal capacity in an innovative way that directly displaces fossil-fuel usage on the FPL system. This facility consists of an array of parabolic trough solar collectors that concentrate solar radiation to heat the HTF. The HTF then circulates through heat exchangers where it generates steam that is integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired combined-cycle plant.

There are several solar-thermal plants in operation around the world. However, none of the other solar-thermal plants are integrated with a combined-cycle plant. Thus, Martin Solar is the first "hybrid" solar plant in the world. As part of a company that has been on the forefront of clean energy innovation nationally, FPL knows well that any new technology presents its own unique operational and performance challenges.

For innovative ideas to succeed, these challenges must be addressed during the initial stages of operation. In the case of Martin Solar, two specific challenges complicate its operation: the highly variable solar resource that exists in Florida and the need to match and integrate process conditions and systems of the solar plant with the existing combined-cycle plant.

Q. Please describe some of the advantages of this new solar technology with regard to the Martin site.

A. Because Martin Solar integrates the solar field into an existing power plant, additional capital infrastructure, such as a new steam turbine, transmission lines and high-voltage transformers was not required. Also, Martin Solar operates within the existing permitted water supply requirements of the Martin power plant. As such, the project results in reduced system-wide fuel costs and emissions without many of the capital expenditures associated with new generation capacity. In addition, it is important to note that FPL constructed the Martin Solar facility for approximately $70 million less than its original budget, providing cost savings to customers over the life of the project.

Q. How did Martin Solar perform in 2011?

A. The plant generated 28,982 MWh of emission-free energy, at a capacity factor of 4.4 percent. This was below FPL's projection that Martin Solar would operate at a capacity factor of 23.6 percent and generate 155,000 MWh in 2011. The lower output was primarily due to three factors: the HTF incident that occurred on June 1, 2011, pre-heater repairs, and planned and unplanned outages at the interconnected Martin Unit 8 combined-cycle plant. While FPL had projected that Martin Solar would operate without significant unplanned outage time in 2011, it is certainly not surprising for a first-of-a-kind plant to have significant downtime during its first year of operation. FPL has responded appropriately to the challenges that have occurred and feels confident that the plant will begin to deliver strong, dependable performance.

Q. Please explain the HTF release at Martin Solar.

A. On June 1, 2011, the solar field was taken offline after the HTF system experienced a high-pressure excursion which lifted a safety-relief valve on an overflow vessel. A vapor plume of steam mixed with HTF was released from the valve and traveled west toward the cooling tower. As the vapor condensed, it fell onto the ground below. The area affected includes the solar power block, the south side of Unit 8, and the area directly west of the Unit 8 power block. This incident was self-contained on the plant's property, and FPL responded swiftly and aggressively to address the release, informing the required authorities and enlisting the necessary resources to clean up the HTF. The Florida Department of Environmental Protection ("DEP") has soil cleanup target levels for substances contained in the HTF, hence FPL promptly conducted assessment and remediation activities to identify and remove soil where the target levels were exceeded. DEP conducted a follow-up inspection and found that the assessment and remediation had been conducted in compliance with its requirements.

FPL has determined that the primary cause of the HTF incident was a vendor error in implementing a modification to the control system logic for the HTF system, coupled with water leaks into the HTF system that occurred through the feedwater pre-heaters. The vendor paid FPL $4,500,000 to help defray expenses for the 2011 unplanned maintenance and repairs at Martin Solar. The Martin Solar site was offline for approximately four months after the event for remediation of impacted soil, asphalt, and gravel that was impacted by the HTF incident, repair of plant equipment and implementation of countermeasures to prevent recurrence. The availability of Unit 8 was not affected by the solar facility repairs.

Q. Could FPL reasonably have anticipated the HTF incident at Martin Solar?

A. Unfortunately, no. As previously discussed, as the first plant of its kind in the world, Martin Solar's operations are unique. Martin Solar presents many operational characteristics that differ from experiences at other solar-thermal installations. Nevertheless, FPL is building on "lessons learned" and the success of the repairs and enhancements installed contribute to our continued confidence about the future of this technology.

Q. What countermeasures were implemented at Martin Solar?

A. The most significant countermeasure implemented is the addition of a Cold Reheat ("CRH") steam-path connection to Martin Unit 8 for the B & C solar-steam trains. CRH capability was initially provided in order to increase the available hours of solar operation and was required on only Trains A & D for this purpose. However, after the HTF incident, FPL determined that CRH would be beneficial on all four trains because it could be used during the startup and offline periods to reduce thermal stress on the pre-heaters and thereby mitigate one of the primary causes of the feedwater leaks. Thus, this enhancement will have the dual benefit of increasing plant performance while minimizing the potential of a future release. The CRH addition to Trains B &

C is expected to be completed by the end of April 2012. Until that time, operation of Trains B & C will be limited in order to reduce the potential for additional water leaks.

In addition to extending CRH capability to all four steam trains, control system strategies were developed and equipment upgrades implemented at Martin Solar to ensure safe and reliable operation. Some of the control system and equipment changes include: additional protective runback and trip logic, addition of temperature and flow ramp rate limiters, re-welding of all pre-heater tubesheets, and addition of a relief-valve containment system. Martin Solar already has seen significant performance improvements. In fact, in recent weeks, solar field peak energy production has exceeded the design output of 75 MW. With these additional enhancements, FPL is optimistic that there will be continued improvement in the second quarter of 2012. FPL expects the plant to reach its full operating capability and produce fossil-fuel savings and reduce emissions for the benefit of FPL customers and the state of Florida for years to come.

Q. What impact did the HTF incident have on the 2011 ECRC O&M variance at Martin Solar?

A. The HTF incident costs were $2,233,412 or 96 percent of the Martin Solar $2,319,416 ECRC O&M variance for 2011. The costs incurred included emergency response, remediation of soil, asphalt, and gravel that was impacted by the HTF release, repair of plant equipment and the implementation of O&M countermeasures to prevent recurrence. FPL has fully remediated the release area in compliance with the state's stringent clean-up standards. The total ECRC O&M cost of the incident was $6,733,412. As I noted earlier, the vendor paid FPL $4,500,000 to help defray expenses for the 2011 unplanned maintenance and repairs at Martin Solar. Therefore, the net ECRC O&M cost of the event was $2,233,412.

In closing, it is important to note that Martin Solar produced thousands of megawatt-hours of electricity with zero fuel costs and emissions during its first year of operations, and the plant has a bright future ahead. FPL takes pride in blazing the trail with this groundbreaking design, which marries two clean energy technologies. With lessons learned and improvements implemented, the facility is expected to contribute clean energy for years to come.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 120007-EI

January 13, 2012

Q. Please state your name and address.

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

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

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

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

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review FPL's request to modify its approved Manatee Temporary Heating System Project (the "MTHS Project") to include a manatee temporary heating system ("MTHS") for the Port Everglades Plant ("PPE").

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

A. Yes, I am sponsoring the following exhibits:

- Exhibit RRL-1 – Port Everglades Manatee Heating System Conceptual Location of heated refuge, heater and pump systems.

- Exhibit RRL-2 - Florida Department of Environmental Protection ("FDEP") Industrial Wastewater Facility Permit Number FL0001538 for PPE.
- Exhibit RRL-3 – PPE Manatee Protection Plan ("MPP").
- Exhibit RRL-4 – U. S. Fish and Wildlife Service ("FWS") letter to FPL regarding manatee protection at PPE.

Q. Please briefly describe FPL's currently approved MTHS Project.

A. On April 13, 2009, FPL petitioned the Commission for approval of the MTHS Project, which initially comprised the installation of an electric heating system at the Riviera Plant ("PRV") in 2009, in order to provide a "manatee refuge" by discharging warm water when necessary into the manatee embayment area until PRV is converted to the Riviera Beach Next Generation Clean Energy Center ("RBEC").

On August 28, 2009, FPL petitioned the Commission to expand the MTHS Project to include the Cape Canaveral Plant ("PCC") until PCC is converted to the Cape Canaveral Next Generation Clean Energy Center ("CCEC").

The MTHS Project at PRV and PCC ensures that FPL complies with PRV and PCC's MPPs, which are specific conditions to the PRV and PCC Industrial Wastewater Facility ("IWWF") Permit Numbers FL0001546 and FL0001473 (most recently reissued by the FDEP on August 28, 2010 and February 11, 2011, respectively).

Additionally, the MTHS Project at PRV and PCC ensures that FPL complies with the Marine Mammal Protection Act of 1972 (16 U.S.C. 1361, et. seq.), and the Endangered Species Act of 1973, (16 U.S.C. 1531, et. seq.), which protect the Florida manatee.

Q. Please briefly describe FPL's proposed expansion of the MTHS Project at PPE.

A. On November 21, 2011, FPL petitioned this Commission for a determination of need to undertake a major modernization project at PPE, which will replace the existing conventional steam units with a highly efficient, clean-burning, gas-fired combined cycle unit (the "Modernization Project") to be named the Port Everglades Next Generation Clean Energy Center ("PEEC"). FPL proposes to expand the MTHS Project to include the installation of an electric heating system at PPE in 2012, in order to continue to provide warm water when necessary into the manatee warm water refuge starting in January 2013 and continuing until the Modernization Project is completed in mid-2016. Primary activities integral to the expansion of the MTHS Project at PPE include designing, permitting, and installing pipes, heater and pump systems, interconnection to the FPL power system, and testing, operating, and monitoring the electric heating system and manatees. A conceptual location of the temporary heating system is included as Exhibit RRL-1.

Q. Please describe the environmental laws or regulations requiring FPL's proposed activities at PPE.

A. FPL is proposing to expand the MTHS Project to include PPE in order to help ensure that FPL can comply with PPE's MPP, which is Specific Condition I.D.10 to the IWWF Permit Number FL0001538, issued by the FDEP for PPE on February 27, 2010. Specific Condition I.D.10 to the IWWF Permit states that "the permittee shall continue compliance with the facility's Manatee Protection Plan approved by the Department on August 13, 1999 et seq." The IWWF Permit containing Specific Condition I.D.10 is attached as Exhibit RRL-2. FPL's PPE MPP is attached as Exhibit RRL-3. Please note that the MPP refers to "Specific Condition 20" which has been renumbered as Specific Condition I.D.10 in the current IWWF Permit.

As stated above, the manatee is protected by the Marine Mammal Protection Act of 1972 (16 U.S.C. 1361, et. seq.), and the Endangered Species Act of 1973 (16 U.S.C. 1531, et. seq.). On December 16, 2011, the FWS provided comments in a letter to FPL regarding the Modernization Project. In its letter, the FWS noted that the Marine Mammal Protection Act and the Endangered Species Act do not permit incidental takes. The FWS indicated that measures will be necessary to protect the manatees from cold water impacts during the transition period of the Modernization Project. A copy of the FWS letter to FPL is attached as Exhibit RRL-4.

Q. How has FPL complied with Specific Condition I.D.10 to the PPE IWWF Permit in the past?

A. Historically, FPL has provided warm water in support of the MPP by releasing once-through cooling water from the existing oil and gas-fired steam units at PPE into the discharge canal. The protected area of heated water reserved for manatees is known as the "warm water refuge."

Q. What is a "warm water refuge"?

A. The term "warm water refuge" is used to describe areas of heated water provided by FPL at five of its power plants that offer manatees a safe haven from cold ambient water temperatures. At PPE, the warm water refuge is mainly the discharge canal where the once-through cooling water from Units 1 to 4 is released.

Q. What is the significance of FPL providing heated water to the warm water refuge?

A. The Florida manatee, a subspecies of the West Indian manatee found only in the southeastern United States, is listed as endangered under both the U.S. Endangered Species Act and Florida state law. Most manatees congregate at confined warm water refuges when coastal water temperatures begin to fall below 68°F. The exact thresholds at which manatees succumb to cold and die are uncertain and can vary between individuals. However, when extremely cold winter temperatures occur, large numbers of manatees may die or have their health impaired. Many of the natural warm water habitats historically used by manatees are no longer available to them. The outflows from power plants like PPE have provided a valuable substitute for these lost natural resources.

Manatees are known to inhabit the Intracoastal Waterway in the vicinity of PPE year-round, and they congregate at the PPE warm water refuge during periods of colder temperatures because of the heated water discharges from the plant.

Q. How many manatees can be found in the Intracoastal Waterway in the vicinity of PPE and the PPE warm water refuge?

A. Aerial surveys for manatees have been conducted by Mote Marine Laboratory on behalf of FPL for decades. On January 24, 2009 a record of 454 manatees were observed in the vicinity of PPE, including 26 calves. Mote Marine Laboratory conducted two surveys at PPE and observers noted 164 and 391 manatees on December 10 and 16, 2010, respectively.

Q. Why does FPL now need a different heating source for PPE?

A. Implementing the Modernization Project will require that the existing steam units be dismantled and the new combined cycle facility be built. During this construction period, no generating units will be available to provide warm water for compliance with the MPP. The current schedule for the Modernization Project requires that the existing conventional steam units be taken out of service in January 2013 to begin the project.

Q. Please describe the temporary heating system proposed for PPE.

A. The proposed temporary heating system will consist of an approximately 12-million Btu per hour electric heater along with the associated pumping system, piping, and electrical equipment. The intake piping and pump systems will be installed in the vicinity of the western terminus of the existing discharge canal. Marine water will be pumped through the electric heater and discharged into the easternmost portion of the temporary manatee refuge area when the ambient water temperature falls below a specified trigger temperature. The water depth in this area varies from approximately 6 to 18 feet. The proposed temporary heating system has been modeled to provide approximately 0.4 acres of water at or above 68°F during the conditions under which the MPP requires that FPL endeavor to provide heated water for manatee protection.

Q. How did FPL determine the size of the electric heater?

A. To determine the size of the heater required to comply with the MPP requirement, FPL retained an environmental services firm to perform computer modeling of the minimum thermal output needed to generate and maintain a warm water refuge consistent with the FWS and Florida Fish and Wildlife Conservation Commission ("FWC") size guidance and discussions with their staff. FPL utilized the CCEC and RBEC experience and discussions with FWS and FWC personnel regarding site-specific conditions at PPE to refine the preliminary design basis for the temporary heating system. For example, the size of the electric heater proposed for PPE is smaller compared to the

CCEC and RBEC MTHS due to the higher ambient water temperatures around PPE. Additionally, the proposed location for the warm water refuge at the far western terminus of the discharge canal (approximately one mile from the Intracoastal Waterway) helps maximize heat retention.

Q. Why does the temporary heating system at PPE need to be installed in 2012?

A. The MPP currently defines the manatee heating season at PPE to be from November 15 to March 31 each year. The Modernization Project schedule dictates that FPL have an alternative heating source at PPE by January 31, 2013, when the existing steam units are taken out of service during the middle of the manatee heating season. The PPE MTHS will remain in service to help avoid potential adverse impacts from cold water to manatees congregating at PPE's warm water refuge during the manatee heating seasons of 2013 through 2016.

Q. What conclusions did FPL reach regarding the preferred alternative for providing warm water to manatees at PPE?

A. FPL's experience with providing temporary warm water refuges for manatees as part of the ongoing PRV and PCC modernization projects has proven the proposed approach to be a reliable form of manatee protection. Installing the temporary heating system allows FPL to respond quickly to weather threats to manatees. FPL is also working with the FWS and FWC on a MTHS operational management plan that recognizes the potential availability of a warm water refuge nearby at FPL's Lauderdale Plant. In the FWS letter to FPL, the agency suggested the size of the PPE MTHS could be scaled down if operation of the system is linked to the Lauderdale Plant warm water refuge. The conceptual management plan for the only two Broward County warm water refuges for manatees is intended to encourage the movement of manatees away from the Port of Port Everglades during the Port's harbor deepening project. The Port's project schedule overlaps FPL's timeline for the Modernization Project. As outlined by the FWS letter, FPL nonetheless must provide a warm water refuge when the Lauderdale Plant is not operational.

Q. Has FPL estimated the cost of the proposed PPE MTHS?

A. The total estimated capital cost for the PPE temporary heating system in 2012 dollars is $3.25 million. This estimate includes expenditures for the equipment, design and engineering of the system, labor for installation, and interconnection to the FPL power system. FPL does not expect to begin recovering capital costs for the PPE MTHS until the system goes into service in January 2013. Because FPL does not expect to need the temporary heating system once the modernized combined cycle unit goes into service, FPL plans to dismantle the system at that time. Therefore, FPL proposes to amortize the cost of the system over its operating life at PPE (i.e., the 42 months from January 2013 through June 2016). FPL will incur removal costs for the temporary heating system in 2016, which will be offset by any salvage value that FPL is able to obtain for the system. Because FPL cannot accurately predict either the removal costs or the salvage value at this time, we have assumed that they net to zero for the purpose of the current cost projections and will true up the projections later as better information becomes available. Of course, any surplus of salvage value over removal costs would be returned to customers via the Environmental Cost Recovery Clause (ECRC). Alternatively, FPL may attempt to use the dismantled equipment at other FPL sites, depending upon equipment conditions and needs, if that proves to reduce costs to customers compared to selling the equipment for its salvage value. This accounting treatment is consistent with the approach approved for the MTHS Project at PRV and PCC.

FPL expects to begin incurring O&M expenses to monitor the manatees at PPE in 2012. Examples of anticipated biological and environmental monitoring activities will include thermal monitoring of ambient and refuge water temperatures, visual observation of manatees utilizing the refuge, potential tagging and tracking of manatee movements, and meetings with FWS and FWC staff to discuss monitoring results. These monitoring expenses will continue throughout the period that the PPE MTHS is in service. In addition, once installation and commissioning of the PPE MTHS is completed in January 2013, FPL will incur O&M expenses associated with materials, supplies and services necessary to maintain the PPE MTHS. FPL's total O&M estimate for 2012 through 2016 is $1.25

million (2012 dollars). These projected O&M costs do not include the electrical costs to operate the temporary heating system. FPL cannot predict how often the system will operate but does not expect the electrical costs to be significant. Therefore, FPL is not seeking recovery through the ECRC process for the electrical costs. Additional activities may be required for compliance with PPE's IWWF and MPP in the future, but FPL is not aware of any such requirements at this time.

Q. Has FPL estimated its 2012 ECRC recovery amount for the PPE MTHS?

A. Based on the projected January 2013 in-service date, FPL has projected $250,000 of O&M expenses in 2012 for the monitoring activities described above.

Q. Please describe the measures FPL has taken to ensure that costs of the MTHS Project at PPE have been minimized.

A. FPL's Engineering and Construction Division will retain an engineering firm to design the temporary heating system. FPL will work closely with the engineering firm, using its prior experience and lessons learned with the temporary manatee refuge heating systems associated with the modernization projects underway at PRV and PCC, to direct the engineering firm's detailed design work. This will ensure a cost-effective design and equipment selection process. A few examples of lessons learned include 1) critical review of the warm water refuge thermal loss mechanisms, including use of a thermal model that divides the refuge into at least six cells and accounts for tidal exchange, advection and convective flows between cells and at the refuge entrance, 2) optimization of the temporary refuge design such as locating the heated water discharge at depth near the refuge entrance and the withdrawal at the opposite end of the refuge to enhance mixing, 3) optimization of the warm water refuge size to provide only the necessary area of heated water for the expected number of manatees at PPE, and 4) coordination of electrical service for the PPE MTHS with the Modernization Project construction plans and schedule, in order to maximize use of existing transformers and electrical feeds.

Using a performance specification for the PPE MTHS equipment recommended by the engineering firm that performs the detailed design, FPL's Integrated Supply Chain (ISC) group will solicit bids from multiple suppliers to determine the source providing the overall best value. The ISC group provides enterprise-wide leadership, direction, and operation of a fully integrated supply chain supporting the procurement, materials management, and logistic needs of FPL and the MTHS Project at PPE. ISC's objective is to drive down costs to FPL and ensure the delivery of the highest quality goods and services. Well-established corporate policies and procedures dictate that for the MTHS Project at PPE, the materials supply contract and the construction contract will be competitively sourced.

FPL's Project Controls group has established a scope, budget, and schedule to meet the needs of the PPE MTHS. Project Controls is also responsible for tracking all MTHS Project costs through various approval processes, procedures, and databases.

Q. Is FPL recovering through any other mechanism the costs for the PPE MTHS Project for which it is petitioning for ECRC recovery?

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 120007-EI

August 1, 2012

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes.

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 for recovery through the Environmental Cost Recovery Clause (ECRC) several new environmental compliance activities: the Thermal Discharge Standards Project, the Gopher Tortoise Relocations Project and the Steam Electric Effluent Guidelines Revised Rule Project. All of these projects were identified in FPL's List of New Projects filed July 10, 2012. Additionally, I also present updates to FPL's approved NPDES Permit Renewal Requirements and CAMR projects.

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

A. Yes. I am sponsoring the following exhibits:

- RRL-5 - relevant excerpt from the Cape Canaveral Plant (PCC) State IWW Permit
- RRL-6 - relevant excerpt from the Riviera Plant (PRV) NPDES Permit
- RRL-7 – new Gopher Tortoise Guidelines
- RRL-8 - relevant excerpt from the St. Lucie Plant (PSL) NPDES Permit

<u>Thermal Discharge Standards Project</u>

Q. Please describe the environmental law or regulation requiring the Thermal Discharge Standards Project.

A. FPL power plants with once-through cooling water systems that were built before July 1, 1972 must meet a "narrative" thermal standard found in Chapter 62-302.520(1) (a)-(c) F.A.C. This rule is implemented through the National Pollutant Discharge Elimination System (NPDES) program. See 33 U.S.C. Section 1342. Pursuant to the U.S. Environmental Protection Agency's (EPA) approval, the Florida Department of Environmental Protection (FDEP) implements the NPDES permitting program in Florida. Affected facilities are required to apply for renewal of the 5-year-duration NPDES permits prior to their expiration.

Facilities that cannot meet the FDEP narrative standard for thermal discharges may apply for a "variance" (i.e. less stringent standards) under Section 316(a) of the Federal Clean Water Act. Section 316(a) ensures that thermal effluent limitations will assure protection and propagation of balanced, indigenous population of shellfish, fish, and wildlife and provides that thermal dischargers can be granted less stringent alternate thermal limits than those imposed by a state program if the discharger can demonstrate that the current effluent limitations, based on water quality standards, are more stringent than necessary to protect the aquatic organisms in the receiving water body.

Prior to 2008, 316(a) variance determinations were conducted using guidance from the EPA that was developed in 1977. If a variance from the state water quality standard for temperature was previously granted, facilities were not required to provide additional information regarding thermal discharges in their renewal application unless changes had been made to the thermal loading in the plant discharge. In 2008, the EPA issued additional guidance on this topic and, with the new guidance, the EPA has taken a much more active role in granting variances, resulting in requests for expanded biological and thermal modeling/monitoring studies to justify the variances.

In addition, many plants that have once-through cooling water systems that discharge heated effluent and were originally deemed compliant with Chapter 62-302.520(1)(a)(c) have been under scrutiny by the FDEP. Oversight of these facilities is also implemented via the NPDES permitting process.

During recent permit renewals, the FDEP, much like the EPA with the 316(a) variances, has taken a more stringent approach to the required demonstration that substantial damage to aquatic organisms is not occurring in the receiving water bodies.

Q. **How does FPL plan to comply with these requirements?**

A. FPL's Cape Canaveral (PCC) Plant has been impacted by the EPA's more stringent 316(a) variance guidance. The most recent version of the PCC State IWW Permit Number FL0001473-012 was issued February 11, 2011 and contains the requirement that a Plan of Study (POS) to justify a 316(a) variance be developed. The relevant excerpt from the PCC State IWW Permit is included as Exhibit RRL-5. FPL submitted a proposed POS to the FDEP in August 2011 and is currently awaiting comments from the EPA and FDEP. FPL anticipates, based on the new EPA guidance and conversations with the EPA Region 4 and FDEP that the scope of the POS may need to be significantly expanded, which would result in substantial increases in compliance costs. FPL's POS proposes baseline (pre-operational) and operational nearfield seagrass and benthic sampling, augmented by ongoing seagrass monitoring conducted by the St. Johns River Water Management District, as well as ongoing fisheries-independent monitoring surveys conducted by the Florida Fish and Wildlife Conservation Commission. If approved by the agencies, the approach of using publicly available information will result in significantly reduced costs compared to having to generate all new information as requested in a January 2011 letter from EPA to FPL. This approach has been successfully used by utilities in other states under the jurisdiction of the EPA Region 4 and resulted in substantially less onerous new sampling and analysis when renewing 316(a) variances. While neither agency has yet approved FPL's proposed POS, FPL has begun baseline sampling in parallel with its continuing efforts to secure approval. Beginning the baseline sampling now is essential in order to stay on track for implementation of the proposal once approved. FPL intends to continue this baseline sampling until the Canaveral Clean Energy Center (CCEC) is operational in 2013. After CCEC is operational, FPL plans to conduct operational sampling in accordance with its proposal, in order to assess impacts of the plant's operation.

The most recent version of the Riviera (PRV) plant NPDES Permit Number FL0001546, issued August 28, 2010 contains language that could result in a substantially higher level of effort to demonstrate compliance with 62-302.520(1) F.A.C. This permit requires a POS that may include baseline biological sampling of the modernized plant and must address monitoring of aquatic species, as necessary, as well as incorporating relevant existing data. The relevant excerpt from the PRV NPDES is included as Exhibit RRL-6. FPL intends to negotiate with the FDEP in 2012 to take a similar approach to the POS that has been proposed for PCC.

Q. Did FPL begin conducting any thermal discharge studies before it petitioned for approval of this project?

A. Yes. Because of the need to conduct baseline sampling, FPL has begun basic reconnaissance sampling at PCC. However, FPL is seeking recovery only for the work that is conducted after it files its petition for Commission approval of the project.

Q. What are the projected total O&M costs associated with this project?

A. FPL's preliminary estimate of O&M costs for this project is $175,000 for 2012 and $175,000 for 2013, which reflects activities needed to implement the POS approach that FPL is proposing for the PCC and PRV sites. The actual compliance costs incurred will depend on the scope of the final POS that are approved for these plants. O&M activities are related to baseline biological studies, other data collection and modeling for both facilities and are expected to begin after August 1, 2012.

Q. What are the projected total capital costs associated with the project?

A. At present, FPL does not anticipate incurring capital costs. However, if studies determine that substantial environmental impacts are occurring, particularly at PCC, substantial capital expenditures could be required.

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

A. Consistent with our standard practice for all consultant services procurements, FPL will competitively bid all of the activities performed by outside firms to ensure costs are prudently incurred. FPL will revise project estimates as specific costs become available through consultant specific bids and costs. FPL will continue to perform due diligence over the life of this project to minimize costs.

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

A. No.

Gopher Tortoise Relocations Project

Q. Please describe the environmental law or regulation requiring this project.

A. The Gopher tortoise (*Gopherus polyphemus*) is a state-designated threatened species, per Rule 68A-27.003(1)(d)3, F.A.C. -- Designation of Endangered Species; Prohibitions, which states: "No person shall take, attempt to take, pursue, hunt, harass, capture, possess, sell or transport any gopher tortoise or parts thereof or their eggs, or molest, damage, or destroy gopher tortoise burrows, except as authorized by Commission permit or when complying with Commission approved guidelines for specific actions which may impact gopher tortoises and their burrows." Gopher tortoises have been creating burrows in the cooling pond embankments at FPL's Martin (PMR), Manatee (PMT) and Sanford (PSN) power plants over time, as well as in the oil tank farm embankments at PMR and PMT. Gopher tortoise burrows must be inspected and then filled as necessary to ensure the integrity of the embankments. Filling burrows means that affected gopher tortoises must be relocated.

Q. How does FPL plan to comply with these requirements?

A. In 2008, the Florida Fish and Wildlife Conservation Commission provided new gopher tortoise guidelines that have changed the permitting process for relocations (i.e., an authorized gopher tortoise agent is now required to conduct surveys and perform relocations and all tortoises now must be sent to a recipient site). The new gopher tortoise guidelines are included as Exhibit RRL-7. The embankments at PMT, PMR and PSN were surveyed from 2008-2011 by plant personnel and no burrows were found that appeared to be compromising the integrity of the embankments. In March 2012, however, surveys were conducted that found gopher tortoise burrows at PMT that could compromise the embankment integrity. In order to fill the burrows at PMT, the gopher tortoises need to be relocated by an authorized gopher tortoise agent in order to comply with Rule 68A-27.003.

As part of normal plant maintenance, FPL conducts periodic surveys at all three sites to ensure that the integrity of the embankments is maintained, but this project is limited to recovery of costs associated with relocations that are required as a result of those surveys. Thus, when FPL plant personnel identify a gopher tortoise burrow requiring filling, an authorized gopher tortoise agent will be contracted to start the relocation process.

Q. Please describe the required activities associated with gopher tortoise relocations.

A. In order to receive a permit for gopher tortoise relocations, an authorized gopher tortoise agent must conduct a survey of the area in question. Once they confirm that the burrow is that of a gopher tortoise, they can apply online for the FWC Conservation Permit. Once the permit is received, the tortoises may be captured via bucket traps, live traps, hand captured outside of burrows, or excavated by hand shovel or backhoe. However, excavation can only be used if it will not compromise the integrity of the embankment. After the tortoise is captured, it will be taken to an offsite, long-term, protected recipient site.

Q. What are the projected total O&M costs associated with this project?

A. FPL cannot predict at this time the costs that it will incur for this project beyond 2012, because the level of activity depends on how many, if any, gopher tortoises require relocation in the future. To the extent that the periodic surveys, which are part of normal plant maintenance activities, identify additional tortoises requiring relocation in the future, FPL would then incur additional relocation related site costs at that time. At this time, a conservative estimate per tortoise needing relocation is $2,500.

Q. What are the projected total capital costs associated with this project?

A. At present, FPL does not anticipate incurring capital costs to comply with the requirements of this project.

Q. Has FPL estimated the 2012 and 2013 ECRC recoverable costs for the proposed project ?

A. Yes. FPL projects that it will begin incurring costs for gopher tortoise relocations in September 2012. FPL's O&M cost estimate for the relocations at PMT is $37,500 in 2012. As previously described, FPL cannot predict at this time the costs that it will incur for this project beyond 2012. However, at this time we estimate that $37,500 of O&M will be spent for all three sites in 2013.

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

A. Consistent with our standard practice for all consultant services procurements, FPL will competitively bid all of the activities performed by outside firms to ensure costs are prudently incurred. FPL will revise project estimates as specific costs become available through consultant specific bids and costs. FPL will continue to perform due diligence over the life of this project to minimize costs.

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

A. No. As I previously stated in my testimony, plant personnel conduct surveys, which are part of normal plant maintenance activities and are recovered through base rates. However, this project is limited to recovery of costs associated with relocations that are required as a result of those surveys.

<u>Steam Electric Effluent Guidelines Revised Rule Project</u>

Q. **Please describe the environmental law or regulation requiring this project.**

A. Title 40 Code of Federal Regulations Part 423, which was promulgated under the authority of the Federal Clean Water Act, limits the discharge of pollutants into navigable waters and into publicly owned treatment works by existing and new sources of steam electric power plants. The current version of the rule was published in the Federal Register on November 19, 1982. On September 15, 2009, the EPA announced that they would undertake rulemaking to revise the rule because, "current regulations, which were issued in 1982, have not kept pace with changes that have occurred in the electric power industry over the last three decades." In early April 2012, EPA announced that a draft rule will be signed by November 20, 2012, with a final rule expected by April 28, 2014.

Q. How does FPL plan to comply with these requirements?

A. The EPA has initiated revisions to Title 40 CFR 423 - Steam Electric Effluent Guidelines, which set minimum standards for treatment of wastewater from steam electric power plants. These revisions are directed primarily at waste streams such as ash sluice water and scrubber wastewater from coal-burning facilities, but there could be impacts to nuclear as well as oil and gas-burning facilities.

The EPA visited FPL's Sanford Plant on October 7, 2009 and Manatee Plant on November 16, 2011 to gain a better understanding as to how oil ash is generated and how it is currently handled at oil-fired facilities. FPL explained that, due to the nature of the oil ash and how it differs from coal ash, dry-handling of economizer and air-preheater oil ash is not practical. Nevertheless, based on recent information obtained from the EPA, it appears that the EPA has decided that oil ash contact water will likely be impacted by the revisions to the guidelines and may require either dry handling of all ash, or require oil ash contact water to be segregated from other waste streams and not discharged to waters of the State. FPL is currently studying the impact that this decision would have on its oil-burning facilities; particularly at the Martin and Manatee plants, although also ensuring Turkey Point plant (these will be the three remaining conventional boiler/oil burning plants in the FPL fleet by the time the rule is final) is considered in these oil ash handling scenarios. Results of these analyses will drive FPL's level of effort for addressing this issue in the future.

For FPL's co-owned generating units at SJRPP and Plant Scherer, compliance costs for handling of coal ash are likely to be significantly higher than those units burning oil. No estimates are available at this time, but the most significant costs would be associated with the conversion of the current bottom ash and economizer ash sluicing systems to dry handling and the construction of a new treatment system for scrubber wastewater if required by the final rule. Additionally, EPA's final designation of Coal Combustion Residuals (CCRs) could significantly impact compliance costs for this rule. Should the EPA designate CCRs as hazardous, costs associated with materials product handling and treatment systems would likely result in significant increases.

Other requirements that might appear in the draft and/or final rule that could impact FPL facilities would involve dechlorination systems for cooling water and disposal of wastes from combustion turbine compressors.

In the latter part of 2012, FPL will be conducting extensive sampling and chemical analyses of the Manatee Plant oil ash and metal cleaning waste effluent streams. Results from these analyses will be presented to the EPA to demonstrate the difference between these types of waste streams and waste streams from flue gas scrubbers and other coal ash related processes, which are significantly more complex and difficult to treat prior to a discharge. These analyses will also be used to develop cost estimates for segregating oil ash contact water from other effluent streams and for developing a zero liquid discharge system for those waste streams. FPL's goal is to convince the

EPA that oil ash handling effluent does not need to be regulated under the same strict requirements that apply to coal ash handling effluent. If successful, establishing that distinction will save FPL and its customers hundreds of thousands or perhaps millions of dollars in compliance costs. FPL anticipates that it will engage consultants to assist it in pursuing this goal. FPL expects to have very preliminary cost estimates for the impact of potential revisions to guidelines associated with oil ash handling on the Martin and Manatee plants by the fall of 2012. Additionally, FPL plans to file comments on the draft rule in 2013, which will advocate for the distinction described above, in order to minimize the impact of potential compliance costs. FPL is also working with The Utility Water Activity Group (UWAG), and separately to ensure the best possible outcome regarding impacts to the utility. The revised rule will be implemented on a plant-by-plant basis. It is expected that after the final rule is issued in 2014, State IWW/NPDES renewal permits will contain a compliance schedule to address the new steam electric effluent guidelines requirements. Thus, many of the capital expenses may occur in the 2018-2020 timeframe.

Q. What are the projected total O&M costs associated with this project?

A. In 2012, FPL expects to spend approximately $5,000 conducting analyses of oil ash related effluent streams to provide information for commenting on the upcoming draft rule. In 2013, FPL expects to spend $45,000 in contractor fees to assist with developing and submitting comments on the draft rule. O&M costs beyond 2013 will be associated with the operation of any oil ash or coal ash related treatment/handling systems that are required by the rule. Examples of potential expenses are flue gas scrubber and other wastewater treatment and disposal, ash contact water treatment and disposal, among others. In addition, there could be requirements for other power plant waste streams that may be impacted by the new rule. Potential examples are dechlorination systems at facilities that currently chlorinate once-through cooling water and disposal of combustion turbine off-line washes, among others. It is very likely that these O&M costs, which will begin to be incurred in the 2018-20 time frame will be significant.

Q. What are the projected total capital costs associated with this project?

A. FPL anticipates that the capital costs, particularly for SJRPP will be significant, and may occur in the 2018-2020 timeframe. FPL will not know what those costs might be until the rule is final.

Q. Has FPL estimated the 2012 and 2013 ECRC recoverable costs for this project?

A. Yes. FPL projects that it will begin incurring costs for the Steam Electric Effluent Guidelines Revised Rule Project in August, 2012. FPL's cost estimate for the effluent sampling and analysis is $5,000. In 2013, comments will be required for the draft rule at an estimated O&M cost of $45,000.

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

A. Consistent with our standard practice for all consultant services procurements, FPL will competitively bid all of the activities performed by outside firms to ensure costs are prudently incurred. FPL will revise project estimates as specific costs become available through consultant specific bids and costs. FPL will continue to perform due diligence over the life of this project to minimize costs.

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

A. No.

NPDES Permit Renewal Requirements Project - Update

Q. Please briefly discuss FPL's approved NPDES Permit Renewal Requirements Project.

A. The Federal Clean Water Act requires all point source discharges to navigable waters from industrial facilities to obtain permits under the NPDES program. See 33 U.S.C. Section 1342. Pursuant to the EPA's approval, the FDEP implements the NPDES permitting program in Florida. Affected facilities are required to apply for renewal of the 5-year-duration NPDES permits prior to their expiration. In April 2009, the FDEP amended Rule 62-620.620 (3), F.A.C., requiring all wastewater discharge permits for major facilities, including power plants, to contain whole effluent toxicity (WET) limits. Additionally, the FDEP has required that facilities prepare a Storm Water Pollution Prevention Plan (SWPPP) that conforms to Rule 62-620.100 (m), F.A.C. and 40 CFR Part 122.44(k) when the NDPES permits are renewed. The purpose of the SWPPP is to identify possible pollutant sources that can affect the water quality of stormwater and to set out best management practices (BMPs) that, when implemented, will reduce or eliminate any possible stormwater impacts. FPL has seven plants with NPDES permits that have been renewed in the past few years with several more scheduled for renewal in the next few years.

Q. Please describe the requirement for the update to this project.

A. The renewed NPDES permit for the St. Lucie plant (PSL), which became effective September 29, 2011, contains a requirement that PSL prepare, submit and conduct a Total Residual Oxidants (TRO) Plan of Study (TROPOS). The relevant excerpt from the PCC NPDES Permit is included as Exhibit RRL-8. Because the renewed NPDES permit was not issued until late September last year, FPL did not have an opportunity to reflect the projected costs of complying with the TROPOS requirement in its 2012 ECRC projection filing.

The purpose of the TROPOS is to demonstrate that discharges from the PSL cooling water system meet the States' Class III water quality standard of 0.01 mg/l for total residual oxidants. In the previous permit, PSL had to meet a limit of 0.1 mg/l at the Point of Discharge (POD), which is at the end of the plant's discharge canal before the effluent is discharged to the Atlantic Ocean via diffusers. With the TROPOS, PSL will demonstrate that meeting the previous 0.1 mg/l TRO limit at the POD is equivalent to meeting the 0.01 mg/l Class III water quality standard at the actual discharge point in the Atlantic Ocean.

Q. How will the TROPOS be completed?

A. FPL retained a consultant to prepare and submit the TROPOS to the FDEP for approval. Following FDEP approval, another consultant will be selected via the bidding process to conduct the TROPOS.

Q. Please describe the work to be undertaken by the contractor that is conducting the TROPOS.

A. The TROPOS has not received final approval by the FDEP at this time. However, based on submittals of the initial TROPOS proposal on December 27, 2011 and subsequent comments and conversations with the FDEP, the final plan is expected to be approved by late September of 2012. At that time, a consultant will conduct the TROPOS, which includes a dye study, TRO decay study, a plant-level verification study and a final report over a 25-month period.

Q. What are the projected total O&M costs associated with this update?

A. FPL expects to incur total O&M costs of approximately $140,000 to complete the TROPOS.

Q. Has FPL estimated the 2012-2013 O&M costs associated with this update?

A. Yes. FPL projects spending $20,000 in 2012 and $50,000 in 2013 for O&M costs associated with a dye study, a TROPOS decay study, and a plant-level verification study.

Q. What are the projected total capital costs associated with this update?

A. If the TROPOS demonstration is successful, there will be no capital costs associated with this update. However, per the NPDES Permit requirement, if the TROPOS fails to demonstrate that the discharge from the diffusers meets the TRO Class III water Quality Standard, PSL must prepare a feasibility study to evaluate engineering options to achieve the water quality standard. The preferred solution, which would most likely include capital costs, must be implemented within 24 months of FDEP approval. This would likely be in the

2017-2018 time frame.

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

A. Consistent with our standard practice for all contractor services procurements, FPL will competitively bid all of the activities performed by outside firms to ensure costs are prudently incurred. FPL will revise project estimates as specific costs become available through contractor specific bids and costs. FPL will continue to perform due diligence over the life of this project to minimize costs.

Q. Is FPL recovering the cost of this update through any other mechanism?

A. No.

CAMR Compliance Project - Update

Q. Why does FPL propose to expand the existing CAMR project?

A. In FPL's August 4, 2006 projections filing for its CAMR project, FPL identified that the co-benefits option for mercury control at SJRPP would have been the lowest cost alternative for compliance with CAMR at that time. The installation of Selective Catalytic Reduction (SCR) that was planned at that time for the SJRPP units for compliance with with CAIR would allow the existing scrubbers on these units to increase the capture of mercury as a co-benefit to the primary focus of reducing NOx and SO2 emissions. FPL and co-owner JEA believed that emission reduction from co-benefits would have allowed SJRPP to meet the Phase I of CAMR emission limits. At that time we also recognized that FPL would have to evaluate the need for additional controls to meet the more stringent 2018 Phase II compliance limits of CAMR at a later date. On February 8, 2008, the D.C. Circuit Court vacated EPA's CAMR, instructing the agency to propose a new rule that conforms to the court's opinion. With the vacatur of CAMR, FPL and JEA concluded that a further review of SJRPP's Hazardous Air Pollutants (HAPs) would have to wait until EPA proposed a CAMR replacement rule.

On December 16, 2011, EPA finalized its Mercury and Air Toxics Standards (MATS) rule as a replacement for CAMR under 40 CFR Parts 60 and 63 to meet its obligation under Section 112 for the control of HAP emissions. The MATS rule establishes performance standards for HAPs emissions from coal and oil-fired electric steam generating units including a mercury emission standard that applies only to coal-fired units. In response to the final MATS rule, FPL, and our ownership partner JEA, have identified the need for additional information regarding emission of HAPs from the SJRPP units. An engineering and economic study for MATS compliance at SJRPP is now being initiated to develop a lowest cost alternative compliance plan. The engineering study will evaluate cost and performance options of emission controls available to meet the MATS specifications while maintaining or improving fuel diversity options.

Q. Please describe the costs which FPL currently recovers for compliance with air toxics rules under the CAMR project.

A. FPL currently recovers its share of costs associated with the operation and maintenance of the baghouse/sorbent injection system on Scherer Unit 4, and the Continuous Mercury Emission Monitors on Scherer Unit 4 and SJRPP Units 1 & 2. Considering that the MATS rule has replaced CAMR, FPL believes that it is appropriate to rename the CAMR Project (Project 33) to now be referred to as the MATS Project.

Q. Which activities does FPL intend to include in the proposed expansion of the MATS project?

A. FPL intends to include only those costs for the environmental compliance engineering study for SJRPP at this time. FPL has adjusted its 2012 MATS O&M projections to include the estimated $28,000 cost for its ownership share of the engineering study. However, in the future FPL intends to present under the MATS project for the Commission's review and approval those costs which FPL determines to be necessary for compliance at SJRPP and Scherer with the MATS rule.

Q. Is FPL recovering costs associated with the new MATS engineering study in any other way?

A. No. FPL neither included costs the SJRPP environmental compliance engineering study under any other ECRC project nor under base rates.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 120007-EI

August 30, 2012

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes.

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 for recovery through the Environmental Cost Recovery Clause (ECRC), a new environmental compliance activity, the Numeric Nutrient Criteria Water Quality Standards in Florida Project. This project is associated with sampling, monitoring, and reporting requirements for total phosphorus and total nitrogen (nutrients) discharges at FPL facilities. These requirements will be incorporated into existing National Pollutant Discharge Elimination System (NPDES) permits that will be renewed upon their expiration by the United States Environmental Protection Agency (EPA) or the Florida Department of Environmental Protection (FDEP). Prior to submitting an application for permit renewal to the respective agencies, FPL will need to begin a sampling, monitoring, and summary report process to establish baseline data for the newly created permit parameters. These changes will impact all of the FPL plants located in Florida that withdraw from and discharge to inland Waters of the State. Additionally, my testimony presents an update to FPL's approved Low Level Radioactive Waste Storage Project.

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

A. Yes, I am sponsoring the following exhibits:

- RRL-9 - Chapter 62-302, Florida Administrative Code, Surface Water Quality Standards (FDEP Proposed)
- RRL-10 - Title 40 Code of Federal Regulations Part 131, Water Quality Standards for the State of Florida's Lakes and Flowing Waters (EPA)

Numeric Nutrient Criteria Water Quality Standards in Florida Project

Q. Please describe the environmental law or regulation requiring this Project.

A. The State of Florida has historically utilized a narrative nutrient standard criterion to guide management and protection of its waters. Chapter 62-302.530(47) (b), F.A.C., states that "in no case shall nutrient concentrations of a body of water be altered so as to cause an imbalance in natural populations of aquatic flora or fauna." Several environmental groups in Florida filed a petition in federal court against the EPA alleging the agency failed to comply with its responsibility under the Clean Water Act to oversee the State of Florida in adopting numeric nutrient criteria (*Florida Wildlife Federation, et al. vs. EPA*). In August 2009, the EPA entered a consent decree in the lawsuit under which EPA would publish federal numeric nutrient criteria for Florida and adopt rules for implementation. In December 2010, the EPA noticed the final rule for Water Quality Standards for the State of Florida's Lakes and Flowing Waters in the Federal Register. This rule promulgated numeric water quality for nitrogen/phosphorus pollution in lakes, flowing waters, and springs in order to replace the State of Florida's narrative nutrient provision under Chapter 62-302.530(47) (b), F.A.C.

Based on the EPA action, the FDEP chose to amend Chapter 62-302, F.A.C. Surface Water Quality Standards to include a numeric nutrient criteria component in order to maintain oversight of nutrients within state waters. The FDEP submitted the revised proposal of Chapter 62-302, F.A.C. to the EPA for review and approval in June 2012. The EPA has until January 6, 2013 to implement its final numeric nutrient criteria rule for Florida's freshwaters. In the alternative, the EPA can approve the FDEP revised criteria and withdraw the federal criteria in totality, as requested by the state. The mechanism through which the EPA and FDEP regulate water quality criteria is the NPDES permitting program. Pursuant to the EPA's delegation of authority, FDEP implements the NPDES permitting program in Florida. FPL's Ft. Myers, Manatee, Martin, Putnam, and Sanford plants will be required to do some form of sampling, monitoring, and reporting under the new numeric nutrient standards. The NPDES Industrial Waste Water permits for these facilities will expire and require subsequent renewal beginning in 2012 proceeding through 2017. Compliance requirements under the new rules will begin prior to permit renewal and continue for the life of each facility.

Q. How does FPL plan to comply with these requirements?

A. Regardless of whether the controlling rules end up being EPA's or FDEP's, the rule changes will require sampling, monitoring, reporting, and possible biological health assessments both prior to application for permit renewal and ongoing thereafter. Based on nutrient data, facilities may have to alter water treatment processes to comply with the new standards. FPL's plan to comply with the new requirements is as follows:

1) Total Phosphorus and Total Nitrogen (Nutrient) Sampling, Monitoring, and Reporting – In accordance with this new regulatory requirement, FPL will begin sampling, monitoring, and creating summary reports for nutrients in preparation for application and renewal of the FPL Industrial Waste Water permits issued for power generation facilities adjacent to freshwaters in Florida. Under the new EPA or FDEP rules, FPL expects that all new Industrial Waste Water permits will include revised conditions requiring FPL to conduct monthly sampling, monitoring, and reporting at the intake and outfall structures for levels of nutrients to evaluate the effects of each plant's effluent on established numeric thresholds or load input to the receiving waterbodies. Previous Industrial Waste Water permits either had no requirement for nutrient sampling and reporting or required only monthly sampling at the point of discharge with no reportable limits. To show compliance with the new standards, samples will be collected upstream and downstream of the discharge points. The upstream sample will characterize background conditions, and the downstream sample will characterize the

potential difference in water quality as a result of the discharge. At the intake structure, samples will be collected to quantify the amount of nutrients being drawn into the facility from the ambient waterbody. Based on the comparative sampling results of the nutrient loads withdrawn and discharged, water chemistry treatment changes may be necessary within a facility's water processes.

2) Biological Health Assessments – The EPA and FDEP have placed great importance on the inclusion of biological data in the assessment and determination of compliance with nutrient regulations. For facilities that discharge into waterbodies that have not undergone a site-specific alternative criteria assessment or total maximum daily load approval process, biological health assessments (e.g. Stream Condition Index procedure or Shannon-Weaver Diversity Index method) are necessary to identify and document ambient or anthropogenic conditions which may contribute to adverse biological effects or improvements within a specific portion of a waterbody. The assessment determines whether a site specific interpretation is appropriate. Both the EPA and FDEP rules include site-specific alternative criteria as integral components in evaluating exposure and compliance with nutrient criteria. "Site-specific alternative criteria" is a mechanism to demonstrate that an alternative criterion is more appropriate for portions of a waterbody that do not meet ambient water quality criterion due to natural background conditions or man-induced conditions which cannot be controlled or abated. The Stream Condition Index and Shannon-Weaver Diversity Index establish biological information which may be used to interpret the narrative nutrient criterion in combination with nutrient thresholds. For certain waterbodies, a biological health assessment is crucial in determining

how FPL will comply with the new regulation. The biological health assessment also establishes a baseline for future compliance tracking. FPL plans to prepare a Biological Health Assessment for each individual plant pursuant to Rule 62-302.800, F.A.C. or 40 CFR Part 131(V)(C).

3) Modification to the Martin Plant Water Treatment System – The Martin Plant withdraws facility makeup water from the St. Lucie Canal (C-44), which is fed by Lake Okeechobee. Both of these waterbodies are high nutrient loaded waterbodies; thus, it may be necessary to change the storage and treatment process to dilute or remove nutrient concentrations prior to discharge. To accomplish this design change, infrastructure will have to be installed and the flow process for treating the effluent will have to be changed.

Q. What are the projected total O&M costs associated with Project requirements?

A. FPL expects to incur the following O&M costs for the Project:

Nutrient Water Sampling, Biological Health Assessments (Stream Condition Indexing), Water Chemistry Changes: Total O&M costs are estimated to be $1,600,000 for years 2013 through 2017. Costs associated with the new regulation will continue for the life of each facility.

Q. What are the projected total capital costs necessary to complete these requirements?

A. The only capital costs currently anticipated for this project are the changes in the Martin Plant Water Treatment System. The total capital costs estimated for those changes are $1,200,000 through 2016.

Q. Has FPL estimated the 2013 ECRC recoverable costs for this Project?

A. Yes. FPL estimated that it will begin incurring costs for the Numeric Nutrient Criteria Project requirements in February 2013. FPL's cost estimate for sampling of nutrients at its facilities is $48,600 annually per facility. FPL anticipates that it will need to begin nutrient sampling, monitoring, and creating summary reports for the Ft. Myers, Martin, Putnam, and Sanford plants in 2013, at a total O&M cost of $194,400. Sampling of nutrients will be on-going for all facilities thereafter. FPL's 2013 O&M cost estimates for implementing water chemistry treatment changes are estimated annually at $100,000 each for the Putnam and Sanford plants. FPL's 2013 O&M cost estimates for implementing the Biological Health Assessment are estimated annually at $12,000 each for the Ft. Myers, Martin, Putnam, and Sanford plants. Biological Health Assessments will be on-going for all facilities thereafter.

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

A. Consistent with our standard practice for all consultant service procurements, FPL will competitively bid all of the activities performed by outside firms to ensure costs are prudently incurred. FPL will revise project estimates as specific costs become available through consultant specific bids and costs. FPL will continue to perform due diligence over the life of this project to minimize costs.

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

A. No. As I previously stated in my testimony, some of the old permits had sampling and monitoring requirements for total phosphorus and total nitrogen, but FPL is not seeking to recover any of those existing costs through the ECRC. Rather, FPL is only seeking recovery for new incremental costs incurred as a result of the new rule requirements.

UPDATE TO LOW LEVEL RADIOACTIVE WASTE STORAGE PROJECT

Q. Please briefly discuss FPL's approved Low Level Radioactive Waste Storage Project?

A. FPL's Low Level Radioactive Waste ("LLW") Storage Project was approved by the Commission in Order No. PSC-07-0922-FOF-EI, issued in Docket No. 070007-EI, on November 16, 2007. In this Order, FPL received approval to recover costs associated with the construction of interim on-site facilities at its St. Lucie ("PSL") and Turkey Point ("PTN") nuclear electrical generating units to store its Class B and Class C LLW safely per NRC regulations regarding Standards for Protection Against Radiation at Title I O, Code of Federal Regulations, Part 20. The project was required as a result of loss of access to the LLW disposal facility in Barnwell, South Carolina on June 30, 2008, due to changes to South Carolina environmental law. LLW is physically similar to the type of wastes that are produced in other industrial processes except that LLW has become contaminated with radioactive isotopes that were produced by the nuclear reactor. LLW includes radioactively contaminated rags, absorbents, used protective clothing, laboratory ware, worn out metal parts and components, spent ion exchange (resin) media and spent filter media.

At the time of its original filing in 2007, FPL's preliminary capital estimate to construct the interim storage facilities was approximately $12 million for both of

FPL's nuclear plants. This estimate assumed the interim storage facilities would be constructed within the Radiation Controlled Area (RCA) at PSL and PTN, on a concrete or gravel pad foundation with appropriate concrete curbs. The LLW would be containerized in cylindrical liners compatible with the LLW that is being stored. The liners would be placed inside engineered thick concrete outer containers that completely enclose the liners and would provide both radiation shielding and protection for the enclosed liners. The container array within the facility would be surrounded by an additional shield wall and measures would be implemented to prevent inadvertent entry to ensure radiation standards for the public and for workers are met.

Q. What is the current status of FPL's approved LLW Project at PSL and PTN?

A. The PTN LLW Storage Facility project schedule has been created and the Engineering Package has been completed and issued for construction. A contractor has been selected and contracts are in the process of being created. The construction of the LLW Storage Facility at PTN is planned to commence in September of 2012 and is expected to be completed by September of 2013.

The PSL LLW Storage Facility project has been placed on hold as a result of resources being dedicated to other projects. Completion of the LLW Facility will resume in January of 2013 with the installation of the fiber optics for the fire detection system, installation of the internal shielding, and the rails for the gantry crane.

Q. Please explain the reason for the update to the FPL's approved LLW.

A. The site location for the PTN LLW facility was selected on January 6, 2011. FPL's current capital estimate for the construction of the LLW facility at PTN is now $9.9 million, which represents an increase of $3.9 million from FPL's original estimate provided in 2007. The location selected within the RCA has created additional costs not anticipated in the original estimate. Additional costs include the soil improvements required for the foundation of the building. Other costs include reinforced concrete foundation and slab over the existing Neutralization Basin, relocation of existing power poles and duct banks and additional time and support due to the construction within the RCA.

Q. How was the LLW site at PTN chosen?

A. The project team conducted a Kepner Tregoe (KT) Analysis of ten different construction locations for the PTN LLW. This analysis utilized a list of criteria that determined the location, based on scoring in each criteria. These criteria included cost factors, site preparation, underground utilities to be avoided, adequate area for building footprint, radiological impact, site elevation (flood plain), accessibility, impact on plant operations, etc. The results of the KT Analysis determined the LLW facility at PTN.

Q. What is the amount of projected depreciation and return on investment associated with this project that has been included in the 2013 ECRC factors?

A. FPL has included in the 2013 ECRC factors an amount of $747,474 associated with depreciation and return on investment for the LLW Storage Project.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 120007-EI

APRIL 2, 2012

Q. Please state your name and address.

A. My name is Terry J. Keith, and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

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

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

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the Environmental Cost Recovery (ECR) Clause true-up costs associated with FPL environmental compliance activities for the period January 2011 through December 2011.

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

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

- Form 42-1A reflects the final true-up for the period January 2011 through December 2011.
- Form 42-2A consists of the final true-up calculation for the period.
- Form 42-3A consists of the calculation of the interest provision for the period.
- Form 42-4A reflects the calculation of variances between actual and actual/estimated costs for O&M Activities.
- Form 42-5A presents a summary of actual monthly costs for the period for O&M Activities.
- Form 42-6A reflects the calculation of variances between actual and actual/estimated costs for Capital Investment Projects.
- Form 42-7A presents a summary of actual monthly costs for the period for Capital Investment Projects.
- Form 42-8A consists of the calculation of depreciation expense and return on capital investment. Pages 53 through 57 of Form 42-8A provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each Capital Investment Project.
- Form 42-9A presents the capital structure, components and cost rates relied upon to calculate the revenue requirement 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" shows the calculation of the Net True-Up for the period January 2011 through December 2011, an over-recovery of $976,912, which FPL is requesting to be included in the calculation of the ECR factors for the January 2013 through December 2013 period.

The actual End-of-Period over-recovery for the period January 2011 through December 2011 of $9,685,585 (shown on Form 42-1A, Line 3) minus the actual/estimated End-of-Period over-recovery for the same period of $8,708,673 (shown on Form 42-1A, Line 6) results in the Net True-Up over-recovery for the period January 2011 through December 2011 (shown on Form 42-1A, Line 7) of $976,912.

Q. Have you provided a schedule showing the calculation of the End-of-Period true-up?

A. Yes. Form 42-2A, entitled "Calculation of Final True-up Amount," shows the calculation of the Environmental End -of -Period true-up for the period

January 2011 through December 2011. The End- of- Period true-up shown on Form 42-2A, Page 2 of 2, Lines 5 plus 6 is an over-recovery of $9,685,585. Additionally, Form 42-3A shows the calculation of the Interest Provision of $52,862, which is applicable to the End-of-Period true-up over-recovery of $9,632,723.

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

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

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

A. Yes, they are.

Q. How did actual expenditures for January 2011 through December 2011 compare with FPL's actual/estimated projections as presented in previous testimony and exhibits?

A. Form 42-4A shows that total O&M project costs were $791,523, or 3.3% lower than projected and Form 42-6A shows that total capital investment project costs were $405,720 or 0.3% lower than projected. Individual project variances are provided on Forms 42-4A and 42-6A. Return on Capital Investment, Depreciation and Taxes for each project for the actual period January 2011 through December 2011 are provided on Form 42-8A Pages 1 through 52.

Q. Please explain the reasons for the significant variances in O&M Projects and Capital Investment Projects.

A. The variances in FPL's 2011 O&M expenses and capital expenditures primarily relate to the following projects:

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

Project 1. Air Operating Permit Fees

Project expenditures were $439,826 or 37.2% lower than previously projected. Lower than projected gas prices resulted in less oil-fired operation than estimated for the oil-burning units. In addition, Port Everglades Units 1 and 2 were placed in Inactive Ready Reserve as was the boiler of Turkey Point Unit 2 (the unit's electric generator was in Synchronous Condenser Mode for the majority of the year). Air Permit fees and payments to the State of Florida are based on actual unit operations and performance.

Project 3a. Continuous Emission Monitoring Systems (CEMS)

Project expenditures were $85,222 or 9.8% lower than previously projected. The variance is primarily due to the following reasons:

- Costs associated with CEMS routine maintenance at Sanford Units 4 and 5 were lower than projected due to fewer parts required to be replaced.
- Lower than projected maintenance and troubleshooting activities at the Port Everglades site as a result of the overhaul

performed during the second half of the year.

- Fewer oil sample analyses were required than previously projected due to reduced oil combustion.
- Less calibration gases used and less equipment issues than previously projected on Manatee Unit 3.

This decrease was partially offset by higher costs at Manatee Unit 1 due to air conditioning unit replacements on the unit's CEMS shelter and costs associated with replacing the critical orifice on the new dilution probe along with associated recertification tests required by change-out of CEMS parts. Additionally, the gas regulators for Martin Units 1 through 4 and 8 were all replaced as required under the CEMS QA/QC procedures.

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

Project expenditures were $772,159 or 46.3% lower than previously projected. The variance is primarily due to favorable competitive bidding results and lower storage tank maintenance. FPL elected not to return the Port Everglades Terminal tank to storage service in anticipation of the projected modernization of the Port Everglades steam units and as a result, significant internal repairs were not executed. Additionally, FPL determined to defer touch coating work on the Martin Terminal until 2014 as a result of the review of the tank's roof coating condition. FPL will continue to monitor the tank's exterior coating condition.

Project 8a. Oil Spill Cleanup/Response Equipment

Project expenditures were $14,795 or 6.8% lower than previously projected. This variance is primarily due to the deferral from the fourth quarter of 2011 to the first quarter of 2012 of inspection, restacking and boom layout work scheduled at the Martin Terminal depot as a result of the vendor's delivery time constraints and unavailability of personnel to perform the work. Additionally, materials previously projected to be ordered in December 2011 were ordered and received in 2012.

Project 13. RCRA Corrective Action

Project expenditures were $66,239 or 71.9% lower than previously projected. This variance is primarily due to the Florida Department of Environmental Protection (DEP) audit not requiring remediation as previously projected.

Project 14. NPDES Permit Fees

Project expenditures were $28,748 or 23.1% higher than previously projected. Costs associated with the NPDES permitting renewal process were inadvertently charged to the environmental clause. These charges were reversed in February 2012. Additionally, costs for a chlorination study performed at St. Lucie as a result of a permit renewal condition should have been charged to Project 47 – NPDES

Industrial Waste Water Permits. A correcting entry will be recorded in April 2012.

Project 17a. Disposal of Noncontainerized Liquid Waste

Project expenditures were $22,481, or 34.6% lower than previously projected. This variance is primarily due to lower costs associated with ash processing at Martin Plant as a result of lower than projected unit operation and production of ash from oil due to lower than projected natural gas prices.

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

Project expenditures were $807,482 or 28.6% lower than previously projected. The variance is primarily due to the unusual warm weather at the end of the year. The warm weather caused increases in load demand which made it difficult to obtain equipment clearances (i.e., de-energize equipment) to perform work. In addition, vendors were redirected to perform emergency response work at the Princeton and Rio Substations, and the Manatee Power Plant due to equipment failures.

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

Project expenditures were $123,573 or 8.2% higher than previously projected. The variance is primarily due to an increase in cost to remove arsenic impacted soils at the Cutler Substation. The work involved longer times and additional equipment to remove the top layer of hard coquina rock within certain areas of the substation. This work is being performed under the direction of the Miami-Dade County's Permitting, Environment, and Regulatory Affairs Department ("PERA").

Project 22. Pipeline Integrity Management

Project expenditures were $123,716 or 52.6% lower than previously projected. The variance is primarily due to the deferral of work to remedy two areas of low pipeline cover along the pipeline at Martin Terminal as a result of work permit delays due to DEP and Army Corps of Engineers permitting requirements. Permits were issued in 2012 and related work will be completed in 2012. Costs associated with pipeline digs and repairs were lower than projected as a result of using FPL's direct operating contractor. Additionally, inline inspection survey costs for the TMR-30" pipeline at Martin Terminal were lower than projected as a result of cost effective bidding.

Project 23. Spill Prevention, Control & Countermeasures – SPCC

Project expenditures were $130,654 or 12.2% lower than previously projected. The variance is primarily due to the following reasons:

- SPCC oil diversionary structure maintenance work was rescheduled to 2012 to perform other critical maintenance and emergency response work.
- Deferral of planned maintenance on distribution oil sheds in order

to conduct a condition assessment of the oil sheds to identify specific scopes of work and to address identified maintenance needs.

- Original estimate assumed the installation of larger transformers that would have required preparation or modifications of SPCC Plans. Actual system upgrades did not require preparation or modifications of SPCC Plans.

Project 25. Port Everglades Electrostatic Precipitators - ESP

Project expenditures were $327,186 or 50.4% lower than previously projected. The variance is primarily due to less than projected maintenance activities required during the overhaul of the ESP at Port Everglades Units 3 and 4. Reduced maintenance activities included replacement of fewer broken insulators, fewer plugged ash hoppers and less ash disposal as a result of Units 3 and 4 being in Inactive Ready Reserve status. Activities performed during the outages were necessary to maintain unit availability to provide generation when needed by system operations to serve customer demand.

Project 28. CWA 316(b) Phase II Rule

Project expenditures were $11,345 or 9.3% higher than previously projected. The variance is primarily due to an additional consultant that was retained for regulatory advocacy, as well as technical and policy support for the 316(b) Existing Facilities. The consultant assisted in discussions with Environmental Protection Agency (EPA) and Office of Management and Budget (OMB) policy makers and by providing technical evaluations of impacts based on various regulatory scenarios. This increase was partially offset by a decrease in necessary 316(b) related support work following the compilation and submittal of comments to the EPA on the proposed 316(b) rule in August of 2011.

Project 29. Selective Catalytic Reduction Consumables (SCR)

Project expenditures were $41,830 or 10.9% higher than previously projected. The variance is primarily due to the amount of Anhydrous Ammonia required for Martin Unit 8 in order for the units to comply with the regulatory air operating limits established by the operating permits. Additionally, as a result of the inspection process at Martin Unit 8, the Anhydrous Ammonia tank required repairs to fittings that were showing signs of corrosion at several locations on the tank. These items were indentified and added to the Unit outage to be accomplished while the unit was offline.

Project 30. HBMP

Project expenditures were $15,249 or 49.9% higher than previously projected. The variance is primarily due to costs associated with compliance requirements of emergency diversion schedules (EDS) that are part of the facility's Conditions of Certification but were not included in the projections because it was originally estimated that they would be used only once every 25 years. When the cooling pond level drops below 62 ft., FPL is allowed, per the EDS, to pump more water from the Little Manatee River, even during periods of relatively low river flow. However, data must be collected and a report filed within 30 days of the pond level returning to 63 ft and therefore the cessation of the EDS.

Project 31. CAIR Compliance

Project expenditures were $165,096 or 10.2% higher than previously projected. The variance is primarily due to additional costs of repairing and analyzing premature leaks on the 800 MW finishing superheat boiler tubes at Martin Plant Unit 2 and the requirement of additional chemical sodium bromide to protect them. This increase was partially offset by consumption of less SCR ammonia than estimated during the period. In December 2011, one SJRPP unit was placed in reserve shutdown and the other operating unit's SCR was not in operation in order to avoid catalyst degradation and use of ammonia when not needed for emission reductions.

Project 33. CAMR Compliance

Project expenditures were $374,674 or 16.0% lower than previously projected. The variance is primarily due to a decrease in consumption of Powdered Activated Carbon (PAC) needed to meet the Georgia Environmental Protection Division requirements for mercury removal in the operation of the Scherer baghouse. Lower generation over the fourth quarter of 2011 combined with detuning the precipitators and allowing more fly ash to mix with the PAC injected into flue gasses resulted in a decreased amount of PAC injection needed for effectively removing mercury.

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

Project expenditures were $56,444 or 8.4% higher than previously projected. Due to unfavorable weather delays resulting in idle time during planned maintenance, expenses associated with the divers and the barge were higher than projected. For safety reasons, the divers and the barge could not work on the project during inclement weather.

Project 35. Martin Plant Drinking Water System Compliance

Project expenditures were $29,922 or 134.9% higher than previously projected. The variance is primarily due to unplanned end of life replacement of the water treatment Reverse Osmosis (RO) membranes after a 4-year in-service life. FPL has now included RO membrane replacement on a 4-year basis for future project budgeting.

Project 37. DeSoto Next Generation Solar Energy Center

Project expenditures were $67,268 or 6.9% lower than previously projected. The variance is primarily due to lower than projected costs associated with employee payroll and related expenses, and contractor services. One of the three full time employees at Desoto accepted another position in the company and his payroll and expenses were not charged to the project for the fourth quarter.

Planned contractor services to install additional system monitoring instrumentation were not completed due to resource limitations. Additionally, planned technical support was less than projected.

Project 38. Space Coast Next Generation Solar Energy Center

Project expenditures were $78,154 or 14.7% lower than previously projected. The variance is primarily due to lower than projected costs associated with employee payroll and related expenses, and contractor services. One of the two full time employees at Space Coast spent part of his time supporting Martin Solar Energy Center during the third and fourth quarters. As a result, only a portion of this employee's payroll and expenses were charged to the project. In addition, planned installation of additional system monitoring instrumentation was not completed due to resource limitations. Finally, planned technical support was less than projected.

Project 39. Martin Next Generation Solar Energy Center

Project expenditures were $2,319,416 or 95.7% higher than previously projected. As discussed in FPL Witness Kennedy's testimony, the variance was primarily related to the heat transfer fluid release and countermeasures FPL has taken following the event to prevent recurrence and improve operating performance.

Project 40. Greenhouse Gas Reduction Program

Project expenditures were $6,444 or 11.7% lower than previously projected. The variance is primarily due to a delay in vendor invoicing for training on the use of the Greenhouse Gas Reporting Software that will be utilized to comply with EPA's Greenhouse Gas Mandatory Reporting Rule. Additionally, FPL only participated in the Online Training instead of On-Site Training originally included in projected costs.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project expenditures were $103,197 or 3.8% lower than previously projected. The variance is primarily due to a delay in receiving an invoice from FPL's consultants until February 2012. The consultants were upgrading their invoice processing system to be able to identify various purchase orders associated with the Technical Agreement FPL and United States Geological Services have in place to comply with the FPL Turkey Point Power Plant Groundwater, Surface Water, and Ecological Monitoring Plan and the Quality Assurance Project Plan.

Project 43. NESHAP Information Collection Request Project

Project expenditures were $17,518 or 208.9% higher than previously projected. The variance is primarily due to costs associated with preparation of comments and research submitted to the EPA as part of the NESHAP ICR for control of coal- and oil-fired electric utility steam units. FPL's report identified that control of mercury emissions from oil fired power plants would not be required as the EPA developed emission specifications under the Air Toxics rule. In its final rule, the EPA included emission specifications for mercury only for coal-fired units.

Project 46. St. Lucie Cooling Water Discharge Monitoring Project

Project expenditures were $117,003 or 48.6% lower than previously projected. The variance is primarily due to lower than projected contractor payroll costs and costs projected to be incurred in December 2011 for a Biological Plan of Study that were incurred in January 2012.

Project 47. NPDES Industrial Waste Water Permits

Project expenditures were $13,342 or 40.4% lower than previously projected. The variance is primarily due to costs for Whole Effluent Toxicity (WET) testing performed after the approval of the project that were inadvertently charged to base rate expenses. These costs were removed from base rates and properly charged to the appropriate ECRC account in March 2012.

Capital Variance Explanations

Project 8b. Oil Spill Cleanup/Response Equipment

Project depreciation and return on investment were $17,320 or 13.8% lower than previously projected. The variance is primarily due to additional equipment being retired.

Project 22. Pipeline Integrity Management

Project depreciation and return on investment were $5,991 or 100% lower than previously projected. The variance is primarily due to delayed completion of the Martin Terminal leak detection system project and the delay of the Riviera Beach Energy Center (RBEC) natural gas compressor station. A revision to the projected in-service date of the Martin Terminal 30" Leak Detection System project was required, which shifted implementation from December 2011 to April 2012. The project was rescheduled as a result of unplanned delays in the manufacture of the Motor Operator Valves and Rotork Valve Actuators that are made in Europe. Delay of the RBEC natural gas compressor station resulted in a delay in the planned upgrade to the terminal Supervisory Control and Data Acquisition (SCADA) system to accommodate new meter skids.

Project 31. CAIR Compliance

Project depreciation and return on investment were $291,923 or 0.6% lower than previously projected. The variance is primarily due to lower than projected construction costs for installation of emission controls on Scherer Unit 4 as a result of a reduction in actual labor hours due to lessons learned during construction of Scherer Unit 3 controls and lower than projected wages as a result of reduced pressure on wage increases due to the current status of the economy.

Project 36. Low-Level Radioactive Waste Storage

Project depreciation and return on investment were $29,093 or 6.2% lower than previously projected. The variance is due to a shift in the in-service date of a waste storage facility from May 2011 to July 2011.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 120007-EI

August 1, 2012

Q. Please state your name and address.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

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

Q. Have you previously testified in this docket?

A. Yes, I have.

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

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 2012 through December 2012.

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

A. Yes, I have. My exhibit TJK-2 consists of nine forms, PSC Forms 42-1E through 42-9E, included in Appendix I. Form 42-1E provides a summary of the Actual/Estimated True-up amount for the period January 2012 through December 2012. 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 13 through 71) reflects return on capital investments and depreciation by project. Form 42-9E provides the capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return applied to capital investments and working capital amounts included for recovery for the period January 2012 through December 2012.

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

A. Forms 42-2E and 42-3E show the calculation of the ECRC Actual/Estimated True-up amount. The Actual/Estimated True-up amount for the period January 2012 through December 2012 is an over-recovery, including interest, of $7,620, (Appendix I, Page 4, line 5 plus line 6). This Actual/Estimated True-up consists of actual data for January 2012 through June 2012 and revised estimates for July 2012 through December 2012, compared to original projections for the same period.

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

A. Yes, with the exception of the Thermal Discharge Standards Project, Steam Electric Effluent Guidelines Revised Rule Project and Gopher Tortoise Relocations Project, all of which are discussed and supported in the testimony of FPL witness Randall R. LaBauve and identified in FPL's List of New Projects filed July 10, 2012. In addition, the modification to the Manatee Temporary Heating System Project to include a manatee temporary heating system for the Port Everglades plant filed in this Docket on January 13, 2012, has not been previously approved by the Commission.

Q. How do the Actual/Estimated project expenditures for January 2012 through December 2012 compare with original projections?

A. Form 42-4E (Appendix I, Page 7) shows that total O&M project costs were $3,452,666 or 12.2% lower than projected and Form 42-6E (Appendix I, Page 10) shows that total capital investment project costs were $2,189,968 or 1.3% higher than projected. Individual project variances are provided on Forms 42-4E and 42-6E. Return on Capital Investment and Depreciation for each project for the Actual/Estimated period are provided on Form 42-8E (Appendix I, Pages 13 through 71).

Following are explanations for FPL's approved O&M Projects and Capital Investment Projects with significant variances.

O&M Project Variances

Project 1. Air Operating Permit Fees

Project expenditures are estimated to be $783,832 or 60.8% lower than previously projected. Lower than projected natural gas prices resulted in significantly less oil-fired operation than estimated for the oil-burning units. Air Permit fees and payments to the State of Florida are based on actual unit operations and performance.

Project 3a. Continuous Emission Monitoring Systems (CEMS)

Project expenditures are estimated to be $148,242 or 19.6% lower than previously projected. The variance is primarily due to the following reasons:

- Fewer oil sample analyses were required than previously projected due to reduced oil combustions as a result of lower than projected gas prices.
- Lower than projected costs for Data Acquisition and Handling System (DAHS) 24/7 software support that resulted from vendor discounted unit support fees as the number of total units supported under the contract has increased.
- Lower than projected costs associated with CEMS routine maintenance at Ft. Lauderdale, Putnam, Sanford, Pt. Everglades, and Ft. Myers plants due to less run time as a result of lower than projected natural gas prices and fewer

parts required to be replaced.

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

Project expenditures are estimated to be $466,470 or 21.3% lower than previously projected. The variance is primarily due to opportunities to eliminate storage tank work previously projected for 2012. At the time of the original projection filing, it was not yet clear whether the Port Everglades plant would be modernized. As a result of the approval of the modernization project at the Port Everglades plant, the Fuel Oil Terminal facility will be decommissioned in 2013, and therefore the replacement of asphalt storage tank aprons on tanks 801, 802, 807 and 808 at the terminal was not performed. Additionally, with the decommissioning planned for Sanford Unit 3 in 2013/2014, an Alternate Procedure was submitted to the Florida Department of Environmental Protection (FDEP) requesting to forego the API-653 internal tank inspection on Sanford Plant Units 3A, 3B and light oil tanks scheduled for August 2012 and proceed to decommissioning and clean closure in 2013/2014. Concurrence from the FDEP on our Alternate Procedure is forthcoming. Finally, there were lower than projected mechanical repairs resulting from the Martin Fuel Terminal T-1271B Storage Tank API internal inspection.

Project 8a. Oil Spill Cleanup/Response Equipment

Project expenditures are estimated to be $190,461 or 89.6%

higher than previously projected. The variance is primarily due to the development and deployment of Hazardous Worker Operations Training (HAZWOPER) 40hr, 24hr, 8hr and Incident Command Training required for FPL's Oil Spill Response teams to be in compliance with OPA 90 regulations. With updates to the facility response plans in the first quarter of 2012, a substantial gap was indentified in the number of HAZWOPER trained personnel on the Initial Spill Response teams and Corporate Oil Spill response team. The majority of these costs are associated with third party vendors that provide this specialized classroom training.

Project 13. RCRA Corrective Action

Project expenditures are estimated to be $76,000 or 76% lower than previously projected. The variance is primarily due to delays in receiving the final approval of the deed restriction package from the FDEP. The work plan for completion has been deferred until approval is received.

Project 14. NPDES Permit Fees

Project expenditures are estimated to be $40,875 or 35.5% lower than previously projected. A reversing entry was recorded in February 2012 for 2011 costs associated with the NPDES permitting renewal process that were inadvertently charged to the environmental clause. Additionally, a correcting entry was recorded in April 2012 for a chlorination study performed at the St.

Lucie plant as a result of a permit renewal condition that should have been charged to Project 47 – NPDES Industrial Waste Water Permits in 2011.

Project 17a. Disposal of Noncontainerized Liquid Waste

Project expenditures are estimated to be $59,748 or 27.0% lower than previously projected. The variance is primarily due to work at Port Everglades Plant that was originally budgeted in the ECRC that will now be charged to the Port Everglades Modernization Project. The work at Port Everglades Plant included site remediation and removal of the ash basins.

Project 19a. Substation Pollutant Discharge Prevention & Removal

Project expenditures are estimated to be $1,269,224 or 45.0% lower than previously projected. The variance is primarily due to manufacturing delays in the delivery of certain transformer components (e.g., radiators and bushings) from vendors, which has caused a reduction in the work schedule. These components are needed prior to performing transformer regasketing work. The components are expected to be delivered early next year.

Project 22. Pipeline Integrity Management

Project expenditures are estimated to be $46,708 or 9.8% lower than previously projected. The variance is primarily due to lower than estimated costs for work completed to remediate an area of low pipeline ground cover along the pipeline at Manatee Terminal found during a routine inspection.

Project 23. SPCC – Spill Prevention, Control & Countermeasures

Project expenditures are estimated to be $180,585 or 18.9% higher than previously projected. The variance is primarily due to costs that were reclassified from Capital to O&M. The replacement of Sanford Plant's Oily Water Separator was identified as not being a full replacement of the system and therefore, did not meet the capitalization policy. In addition, Martin Units 3 and 4 had unplanned repairs to the secondary containment around the diesel storage tank. The unplanned repairs included concrete cracks and expansion joint repairs. This variance was partially offset by a decrease in the substation oil diversionary structure (i.e., perimeter curbing) repair, which was deferred in order to negotiate new contracts with vendors.

Project 24. Manatee Reburn

Project expenditures are estimated to be $258,659 or 28.7% higher than previously projected. The variance is primarily due to a shift in work at Manatee Plant from 2011 to 2012 due to changes in the outage schedules that occurred after the approval of the 800 MW ESP project. This work includes the replacement of the Unit 1 and 2 Burner Scanners and Igniters, Unit 1 and 2 Burner Guide Tube Assemblies and Unit 1 Burner Swirlers.

Project 25. Port Everglades Electrostatic Precipitator (ESP)

Project expenditures are estimated to be $308,749 or 48.2% lower than previously projected. The variance is primarily due to lower than anticipated unit operation on fuel oil as a result of lower than projected natural gas prices. In addition, projected costs associated with the ESP overhaul at the Port Everglades plant will not be incurred. As a result of the modernization of the facility in 2013, the overhaul will no longer be performed.

Project 28. CWA 316(b) Phase II Rule

Project expenditures are estimated to be $1,111,073 or 93.9% lower than previously projected. EPA announced on July 18, 2012 that issuance of the new 316(b) rule would be delayed until July 27, 2013 (although this does not preclude EPA from issuing it earlier). As a result, it is now anticipated that originally projected 2012 costs for studies will be spent in 2013. Also, costs for Manatee, Sanford and Putnam plants with closed cooling systems were removed from the budget since it is unlikely that the final rule will apply to these plants. Since the rule is not final, these revised estimates are subject to change pending the specific documentation and schedule requirements in the final rule.

Project 29. SCR Consumables

Project expenditures are estimated to be $144,143 or 41.2% higher than previously projected. The variance is primarily due to unexpected repairs of the Anhydrous Ammonia tank at the Martin and Manatee plants found during the planned inspection required by the plants' risk management plans per the Air Permit Facility-Wide Conditions (FW9), and by regulation under 40 CFR Part 68.

The Anhydrous Ammonia tank required repairs to fittings that were showing signs of corrosion at several locations on the tank. The ammonia system had to be drained in order to repair the fittings and as a result ammonia costs increased. In addition, there were unanticipated costs associated with the inspection of the ammonia piping at the Manatee plant. As part of the plants' risk management plans, this inspection will occur every five years and will require a piping Non Destructive Examination (NDE) inspection, pipe coating and the removal of pipe lagging.

Project 31. CAIR Compliance

Project expenditures are estimated to be $1,120,991 or 24.1% lower than previously projected. The variance is primarily due to lower than expected operating expenses of the Scherer Unit 4 Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) as a result of a change in the start of the planned duct tie-in outage in 2012. This resulted in the final installation and testing of the SCR and FGD to occur later in the year than originally projected which reduced expected operating expenses. The SCR completed testing and was placed in service June 14, 2012 and testing of the FGD is expected to be completed in August 2012. Ammonia injection costs decreased as a result of less operating hours of the SJRPP SCR due to cost efficiencies. In addition, subsequent to FPL's projection of anticipated legal costs for challenging the Clean Air Interstate Rule (CAIR), on December

23, 2011, the U.S. Court of Appeals for the D.C. Circuit unexpectedly stayed the CSAPR rule, resulting in lower than projected legal expenses for 2012.

Project 32. BART Compliance

Project expenditures are estimated to be $15,900, versus an original estimate of $0. As a result of the Circuit Court's vacature of CAIR, Florida's Regional Haze State Implementation Plan (SIP), which relied on EPA's assertion that CAIR was equal to BART (Best Available Retrofit Technology), was no longer valid for emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx) which were part of the Clean Air Visibility Rule (CAVR). Therefore, several of our BART-eligible plants that were formerly exempt from BART controls for SO2 and NOx (Putnum Units 1 and 2, Turkey Point Units 1 and 2, Manatee Units 1 and 2, and Martin Units 1 and 2), are now required to develop 5-factor BART determinations and conduct visibility modeling to satisfy the BART requirements of CAVR. This was unanticipated until late 2011. The additional charges are consultant fees to develop the BART determinations and visibility modeling for the four plants identified above.

Project 37. DeSoto Next Generation Solar Energy Center

Project expenditures are estimated to be $127,739 or 11.5% lower than previously projected. The variance is primarily due to lower than projected costs associated with employee payroll and related expenses, and overheads as a result of obtaining more experience in maintaining the Desoto and Space Coast facilities. It was determined that the site personnel at Desoto could also support Space Coast Next Generation Solar Energy Center reducing the payroll costs and expenses remaining at Desoto. Additionally, planned technical support payroll and expenses were less than projected as a result of less fleet team support.

Project 38. Space Coast Next Generation Solar Energy Center

Project expenditures are estimated to be $306,336 or 51.2% lower than previously projected. The variance is primarily due to lower than projected costs associated with employee payroll and related expenses, overheads, and contractor services. Two full-time positions included in the original budget will not be filled as maintenance and operations are now covered by personnel stationed at the Desoto Next Generation Solar Energy Center. In addition, the new grounds maintenance contract was renegotiated at a lower monthly cost and planned technical support was less than projected.

Project 39. Martin Next Generation Solar Energy Center

Project expenditures are estimated to be $1,059,615 or 42.7% higher than previously projected. The variance is primarily due to higher maintenance costs, employee payroll, and gas usage. The number of solar employees increased from 7 to 15 for a total increase of $577,979 annually. The original staffing of 7 employees was based primarily on the number required to perform basic outside operations duties, inspection of watch, and minor maintenance. FPL planned to determine how much staffing was required after some operational experience and then increase staffing as needed. After several months of operation it became apparent that additional staffing was required to perform operational and maintenance duties. Four of eight employees were added in November, 2011 and the balance were added in January, 2012.

Mirror washing costs have also increased from the original 2012 estimate by $221,000. The original 2012 budget was based on washing mirrors every two weeks. FPL learned subsequently that mirror washing must be performed daily in order to maintain performance. A more aggressive cleaning schedule began in 2012 and will have an annual estimated cost of $459,238.

Additionally, nitrogen gas usage is greater than planned. Nitrogen gas is used to displace the water that mixes with the heat transfer fluid. FPL projects an additional cost of $147,900 for increased gas usage.

Lastly, the preheater leak repairs began in June 2012 in the amount of $175,000. Additional preheater leaks caused FPL to exceed their original maintenance budget.

Project 40. Greenhouse Gas Reduction (GHG) Program

Project expenditures are estimated to be $58,500 or 97.5% lower than previously projected. The variance is primarily due to the purchase of a GHG reporting software and user training in 2011 subsequent to submittal of final projections for 2012. FPL implemented the system in 2011 earlier than anticipated to address initial implementation issues with sufficient margin prior to the regulatory required reporting deadline.

Project 41. Manatee Temporary Heating System Project

Project expenditures are estimated to be $705,074 or 52.8% less than previously projected. The variance is primarily due to lower than expected system operating costs at the Cape Canaveral plant as a result of design enhancements that were identified during the previous manatee heating season (October 2010 through March 2011), as well as unseasonably warm weather. The intake refuge perimeter design enhancement, primarily the addition of a sheet pile wall to minimize the refuge size and open boundary, has improved the capability to maintain the refuge at the required 68°F and thus minimizing the loss of heated water to the Indian River. In addition to the refuge perimeter enhancement, the unseasonably warm weather has resulted in the need to operate the primary heating source less often and no need to operate the supplemental heater. As a consequence, FPL has needed less contracted manpower to operate both heaters, as well as incurring reduced manatee observer labor costs.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project expenditures are estimated to be $1,245,000 or 94.3% higher than previously projected. The variance is primarily due to increased monitoring efforts required by the South Florida Water Management District (SFWMD), the FDEP and Miami Dade County. Preliminary estimates were based on reduced sampling by approximately 50% because of FPL's request to reduce the current sampling requirements. The agencies have not agreed to any of FPL's request at this time and are now requiring additional and more detailed sampling requirements which have increased lab analysis costs. In addition, unanticipated annual geophysical surveys are now being required by the agencies.

Project 45. 800 MW Unit ESP Project

The variance of $433,504 is due to O&M expenditures that were not included in the original 2012 projections because the final MATS rule had not yet been issued. On December 21, 2011, EPA issued the final MATS rule, which has the effect of requiring ESPs for the 800 MW oil-fired units. As a result, the revised estimate now includes O&M costs for the August 2012 - December 2012 period.

Project 46. St. Lucie Cooling Water Discharge Monitoring Project

Project expenditures are estimated to be $576,195 or 57.7% lower than previously projected. The variance is primarily due to reversing charges that were inadvertently included in the budget for this project. In addition, original estimates were based on initial contract bids. FPL has since received lower than estimated fixed price contracts for portions of the scope of work required. Costs were deferred to 2013 due to a shift in the Extended Power Uprate (EPU) outage schedule.

Project 47. NPDES Permit Renewal Requirements

Project expenditures are estimated to be $27,076 or 36.8% higher than previously projected. The variance was primarily due to a chlorination study that was required to be conducted by the St. Lucie Plant NPDES permit renewal that was not included in the original projections.

Project 48. Industrial Boiler MACT Project

Project expenditures are estimated to be $40,453 or 97.6% lower than originally projected. The variance is due to changes that were made to the implementation of the final rules which occurred after Commission approval of FPL's Industrial Boiler MACT project. On February 7, 2012, EPA issued no action assurance letters which granted extensions for boilers at area sources until the earlier of October 1, 2012 or a final rule on the reconsideration of the Industrial Boiler MACT. Additionally, EPA proposed reconsideration for area source boilers which would provide an additional year to comply with the testing requirements. FPL anticipates lower than originally projected costs for combustion tuning with required testing for its industrial boilers at area sources, which will be conducted in the July – December 2012 period following previously scheduled unit maintenance outages.

Capital Project Variances

Project 8b. Oil Spill Cleanup/Response Equipment

Project depreciation and return on investment are estimated to be $49,169 or 34.8% higher than previously projected. The variance is primarily due to charges related to the Discharge Canal and Intake Canal Oil Spill Hard Booms at the Port Everglades plant that were inadvertently charged to the SPCC-Spill Prevention, Control & Countermeasures project in June 2011. These costs were reclassified to this project in March 2012.

Project 31. CAIR Compliance

Project depreciation and return on investment are estimated to be $3,623,938 or 6.1% lower than previously projected. The variance is primarily due to a shift in Scherer Unit 4 FGD costs from 2012 to 2013. Additionally, Scherer Unit 4 SCR equipment and contingency costs were lower than originally projected.

Project 36. Low-Level Radioactive Waste Storage

Project depreciation and return on investment are estimated to be $581,545 or 44.6% lower than previously projected. The variance is primarily due to a change in the in-service date from March 2012 to December 2013 due to the Turkey Point Unit 3 and Unit 4 EPU outages.

Project 45. 800 MW Unit ESP Project

The variance of $6,171,976 is due to project depreciation and return on investment that were not included in the original 2012 projections because the final MATS rule had not yet been issued. On December 21, 2011, EPA issued the final MATS rule, which has the effect of requiring ESPs for the 800 MW oil-fired units. Consistent with the stipulation in Order No. 11-0083-FOF-EI, FPL transferred the construction costs for the Manatee Unit 2 ESP, together with accumulated AFUDC, to ECRC-recoverable accounts as part of its January 2012 accounting entries.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 120007-EI

AUGUST 30, 2012

Q. Please state your name and address.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

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

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

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review and approval FPL's Environmental Cost Recovery Clause (ECRC) projections for the January 2013 through December 2013 period.

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

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

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

A. Yes. Exhibit TJK-3 provides the calculation of FPL's proposed ECRC factors for the period January 2013 through December 2013. TJK-3 includes PSC Forms 42-1P through 42-8P, which are provided in Appendix I.

Q. Is FPL requesting Commission approval of any new or modified environmental projects?

Yes, FPL is requesting approval to recover through the ECRC several new and modified projects, as presented in the testimony of Randall R. LaBauve in this docket. On January 13, 2012, witness LaBauve filed testimony requesting approval of a modification to FPL's approved Manatee Temporary Heating System Project to include a manatee temporary heating system for the Port Everglades Plant. Witness LaBauve's August 1, 2012 testimony presented the Thermal Discharge Standards Project, Steam Electric Effluent Guidelines Revised Rule Project, the Gopher Tortoise Relocations Project, and updates to FPL's approved NPDES Permit Renewal Requirements and CAMR projects. Additionally, witness LaBauve's August 30, 2012 testimony presents the Numeric Nutrient Criteria Water Quality Standards in Florida Project and an update to FPL's approved Low Level Radioactive Waste Storage Project.

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

Commission?

A. Yes.

Q. Please describe Form 42-1P.

A. Form 42-1P (Appendix I, Page 1) provides a summary of projected environmental costs being requested for recovery for the period January 2013 through December 2013. Total environmental requirements, adjusted for revenue taxes, are $214,202,076 (Appendix I, Page 1, Line 5) and include $215,032,494 of environmental project jurisdictional revenue requirements for the January 2013 through December 2013 period (Appendix I, Page 1, Line 1c) decreased by the actual/estimated true-up over-recovery of $7,620 for the January 2012 - December 2012 period (Appendix I, Page 1, Line 2), and by the final true-up over-recovery of $976,912 for the January 2011 – December 2011 period (Appendix I, Page 1, Line 3).

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

A. Form 42-2P (Appendix I, Pages 2 and 3) presents the environmental project O&M costs for the projected period along with the calculation of total jurisdictional costs for these projects, classified by energy and demand. FPL is projecting total jurisdictional O&M costs of $31,753,383 for the period January 2013 through December 2013.

Form 42-3P (Appendix I, Pages 4 and 5) presents the environmental project capital investment costs for the projected period. Form 42-3P also provides the calculation of total jurisdictional costs for these projects, classified by energy and demand. FPL is projecting total jurisdictional capital investment costs of $183,279,110 for the period January 2013 through December 2013.

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

Q. Please describe Form 42-4P.

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

Q. Has FPL made any changes to the methodology for calculating the allowable return on investments recovered through the ECRC?

A. Yes. Per the Stipulation and Settlement Agreement approved by the Commission in this docket on August 14, 2012, FPL is using the Weighted Average Cost of Capital from its May 2012 Earnings Surveillance Report to calculate the return on average net investments included for recovery through the ECRC.

Q. Please describe Form 42-5P.

A. Form 42-5P (Appendix I, Pages 39 through 109) provides the description and progress of environmental projects included in the projected period.

Q. Please describe Form 42-6P.

A. Form 42-6P (Appendix I, Page 110) calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Q. Have you revised the methodology used to allocate projected kWh sales by rate class?

A. Yes. FPL's sales forecast is developed on a revenue class basis and must be allocated to the rate schedule level in order to calculate its CCR factors by rate schedule. In the past, FPL has allocated its projected kWh sales by rate schedule based on the relationship of each rate schedule's actual kWh sales to total retail kWh sales from the last 12 months of actual sales.

For 2013, FPL is adopting the methodology used in its base rate proceedings, which allocates kWh sales by rate schedule based on the historical relationship between sales by rate schedule, and sales by revenue class. These historical percentages are then applied to the forecast of sales by revenue class. The result is an estimate of sales by retail rate schedule for the appropriate time period.

Q. Please describe Form 42-7P.

A. Form 42-7P (Appendix I, Page 111) presents the calculation of the proposed 2013 ECRC factors by rate class.

Q. Please describe Form 42-8P.

A. Form 42-8P (Appendix I, Page 112) presents the capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return applied to capital investments and working capital amounts included for recovery through the ECRC for the period January 2013 through December 2013.

Q. Is FPL proposing any changes to its approved Port Everglades ESP Project resulting from its petition for a determination of need in Docket No. 110309-EI?

A. Yes. FPL is currently recovering the costs associated with the ESPs on the existing units at the Port Everglades Plant (PPE) through the ECRC and proposes to complete recovery of those ESPs in the ECRC through a capital recovery schedule. The Commission entered Order PSC-12-0187-FOF-EI in Docket No. 110309-EI granting FPL an affirmative determination of need to modernize the 1960's Port Everglades Plant into a high-efficiency combined cycle natural gas energy center. Assuming final approval of site certification for this modernization plan, all of the existing PPE units will be retired effective January 2013. FPL is requesting to include in its 2013 ECRC factors the recovery of the unrecovered net investment balance of the PPE ESPs at the time of the planned retirement on a four year capital recovery schedule beginning January 1, 2013.

Q. Has FPL proposed any adjustment to ECRC recovery in its rate case petition and supporting testimony and exhibits that were filed in Docket No. 120015-EI?

A. As stated in FPL witness Kim Ousdahl's testimony filed in Docket No. 120015-EI, FPL is proposing to recover all costs associated with FPL's approved Substation Pollutant Discharge Prevention Project through the ECRC and remove them from base rates. Order No. PSC-97-1047-FOF-EI, issued on September 5, 1997, required FPL to adjust ECRC O&M expenses downward for costs related to substation transformer gasket replacement, substation soil contamination remediation and the painting of the substation transformers because those historical cost levels were deemed to be already recovered through base rates. FPL has been reducing clause recoverable expenses by approximately $47 thousand per month and including the same amount in base rate O&M cost. In the rate case docket, FPL is asking the Commission to discontinue the current treatment and approve the Company's adjustment to decrease base rates in the annual amount of $560 thousand and include actual costs incurred on an ongoing basis in the determination of ECRC recoverable costs. Should FPL's rate case request be approved, FPL will reflect the results in the 2013 true-up process.

Q. Have you made any adjustments to FPL's 2013 ECRC factors to reflect the proposed Stipulation and Settlement Agreement (the Agreement) filed in Docket No. 120015-EI on August 15, 2012 ?

A. No. At the time that I prepared my testimony, the Commission had not ruled on the Agreement. If the Agreement is approved, FPL will reflect the results in the 2013 true-up process.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

April 2, 2012

Q. Please state your name and business address.

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

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

A. I am employed by the Environmental Services and Strategy Department of Progress Energy Florida ("Progress Energy" or "Company") as Manager of Environmental Services / Power Generation Florida.

Q. What are your responsibilities in that position?

A. I am responsible for ensuring that environmental technical and regulatory support is provided to Power Generation Florida for the implementation of compliance strategies associated with the environmental requirements for power generation facilities in Florida.

COM 5
APA 1
ECR 6
GCL 1
RAD 1
SRC
ADM
OPC
CLK
Crt Rep 1

Q. What current PSC-approved projects are you responsible for?

A. I am responsible for Pipeline Integrity Management (Project No. 3); Aboveground Storage Tank Secondary Containment (Project No. 4), Phase II Cooling Water Intake (Project No. 6), CAIR Peaking - Demand (Project No. 7.2), Arsenic Groundwater Standard (Project No. 8), Underground Storage Tanks (Project 10), Modular Cooling Towers (Project No. 11), Thermal Discharge Permanent Cooling Tower (Project No. 11.1), Greenhouse Gas Inventory and Reporting (Project No. 12), Mercury Total Daily Maximum Loads Monitoring (TDML) (Project No. 13), Hazardous Air Pollutants (HAPs) ICR Program (Project No. 14), Effluent Limitation Guidelines ICR Program (Project No. 15), National Pollutant Discharge Elimination System (NPDES) (Project No. 16) and Mercury & Air Toxics Standards (MATS) (Project No. 17).

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between the actual project expenditures and estimated/actual cost projections for environmental compliance costs associated with several approved ECRC projects. In addition, I am sponsoring Exhibit No. __ (PQW-1), which is PEF's review of the efficacy of its Integrated Clean Air Compliance Plan and of retrofit options in relation to expected environmental regulations.

Q. Which projects have a material variances for which you will be providing variance explanations?

A. I will provide an explanation for the Pipeline Integrity Management Program (Project No. 3), aspects of PEF's Integrated Clean Air Compliance Program within my area of responsibility (Project No. 7.2), Modular Cooling Towers (Project No. 11) Mercury TMDL (Project No. 13), NPDES (Project No. 16) and MATS (Project No. 17) for the period January 2011 through December 2011.

Q. Please explain the variance between the actual project expenditures and the estimated/actual projections for the Pipeline Integrity Management (PIM) (Project No. 3) for the period January 2011 to December 2011.

A. Pipeline Integrity Management (PIM) operation and maintenance (O&M) expenditures were $217,985 or 14% lower than projected in the Estimated/Actual filing. This variance is primarily attributable to work originally planned for 2011 being postponed into 2012 while the PIM team undertook sinkhole mitigation efforts. During the summer of 2011 there were areas of geophysical activity that resulted in sinkholes developing in the vicinity of the pipeline. Work to study the geology in these areas took precedent over planned pipeline activities in order to identify and correct conditions that posed risk of damaging the pipeline; therefore, costs for the 2011 PIM program were less than previously projected.

Q. Please explain the variance between the actual project expenditures and the estimated/actual projections for the CAIR Combustion Turbine Predictive Emissions Monitoring Systems (Project No. 7.2) for the period January 2011 to December 2011.

A. The CAIR Combustion Turbine Predictive Emissions Monitoring Systems O&M expenditures were $32,164 or 27% lower for this program than projected in the Estimated/Actual filing. This variance is attributable to reduced costs for software maintenance and a lower number of recertification tests than were originally anticipated.

Q. Please explain the variance between the actual project expenditures and the estimated/actual projections for the Modular Cooling Towers (Project No. 11) for the period January 2011 to December 2011.

A. Modular Cooling Tower O&M expenditures were $481,521 or 15% lower than projected in the Estimated/Actual filing. These costs were expected for demobilization dismantlement activities planned for November and December 2011. The towers were not dismantled as originally anticipated; therefore the associated costs were not incurred. The towers are now scheduled for dismantlement in 2012.

Q. Please explain the variance between the actual project expenditures and the estimated/actual projections for the Mercury TMDL (Project No. 13) for the period January 2011 to December 2011.

A. Mercury TMDL O&M expenditures were $11,663 or 23% lower than projected in the Estimated/Actual Filing. This variance is due to the Florida Coordinating Group project participation assessment fees not being charged to the program as originally expected. This program will not continue into 2012.

Q. Please explain the variance between the actual project expenditures and the estimated/actual projections for the NPDES (Project No. 16) for the period January 2011 to December 2011.

A. NPDES O&M expenditures were $505,123 or 78% lower than projected in the Actual/ Estimated filing. This variance is primarily attributable to a delay in the engineering studies associated with the Bartow plant's freeboard project as well as a delay in the implementation of toxicity testing required by the Crystal River North NPDES permit that was issued later than originally expected.

Q. Please explain the variance between the actual project expenditures and the estimated/actual projections for MATS (Project No. 17) for the period January 2011 to December 2011.

A. MATS O&M expenditures were $85,000 or 100% lower than projected in the Estimated/Actual filing. This variance is due to test reports not being finalized and available until December 2011. These costs will be incurred in 2012.

Q. In Order No. PSC 10-0683 -FOF-EI issued in Docket 100007-EI on November 15, 2010, the Commission directed PEF 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 PEF's retrofit options for each generating unit in relation to expected changes in environmental regulations." Has PEF conducted such a review?

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

Q. Please summarize the conclusions of PEF's review.

PEF has completed installation of the emission controls contemplated in its approved Plan on time and within budget. The new Flue Gas Desulfurization (FGD) and Selective Catalytic Reduction (SCR) systems have enabled PEF to comply with CAIR requirements and will continue to be the cornerstone of PEF's integrated air quality compliance strategy for years to come. PEF is confident that the approved Plan, along with compliance strategies under development, will enable the Company to achieve and maintain compliance with all applicable regulations, including MATS, in a cost-effective manner. PEF is in the process of evaluating additional compliance options in light of the recent adoption of MATS, the ongoing review of CSAPR, and other regulatory developments affecting fossil fuel-fired electric generating units.

Q. Does this conclude your testimony?

A. Yes.

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

AUGUST 1, 2012

Q. Please state your name and business address.

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

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

A. I am employed by the Environmental Services Section of Progress Energy Florida ("Progress Energy" or "Company") as Manager of Environmental Services / Power Generation Florida.

Q. What are your responsibilities in that position?

A. I am responsible for ensuring that environmental technical and regulatory support is provided to the implementation of compliance strategies associated with the environmental requirements for power generation facilities in Florida.

A. I am responsible for Pipeline Integrity Management (Project No. 3); Aboveground Storage Tank Secondary Containment (Project No. 4), Phase II Cooling Water Intake (Project No. 6), CAIR/CAMR Peaking (Project No. 7.2), BART Program (Project 7.5), Arsenic Groundwater Standard (Project No. 8), Underground Storage Tanks (Project 10), Modular Cooling Towers (Project No. 11), Thermal Discharge Permanent Cooling Tower (Project No. 11.1), Greenhouse Gas Inventory and Reporting (Project No. 12), Mercury TMDL (Project No. 13), Hazardous Air Pollutants (HAPs) ICR Program (Project No. 14), Effluent Limitation Guidelines Information Collection Request (ICR) Program (Project No. 15), NPDES Program (Project No.16) and MATS Program (Project 17).

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit No. __ (PQW-1), which includes a letter re: Progress Energy Florida's NPDES Renewal Program and associated Administrative Order that PEF filed in this docket on February 8, 2012; and
- Exhibit No. __(PQW-2), which includes a verified Petition to Modify Scope of Existing Environmental Program that PEF filed in this docket on March 29, 2012.
- Exhibit No. __(PQW-3), which includes a letter re: Progress Energy Florida's Integrated Clean Air Compliance Plan that PEF filed in this docket on May 14, 2012.

A. O&M expenditures for the CAIR/CAMR – Peaking Program are expected to be $47,573 or 52% higher than originally projected. This variance is mainly due to postponement of some testing at the Suwannee and Intercession City plants from 2011 to 2012. In addition, actual costs for some testing and equipment rental were higher than originally anticipated.

Q: Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Best Available Retrofit Technology (BART) Program (Project 7.5) for the period January 2012 to December 2012.

A: O&M expenditures for the BART Program are expected to be $27,000 or 100% higher than originally projected. This variance is due to the need to perform sulfur dioxide (SO_2) emissions modeling in support of the Florida Department of Environmental Protection's (FDEP) ongoing work to amend its State Implementation Plan as directed by the Environmental Protection Agency (EPA). The need for this type of effort was referenced in the May 14, 2012 update of PEF's Integrated Clean Air Compliance Plan provided as Exhibit No. __ (PQW-3).

Q: Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Modular Cooling Towers (Project 11).

A: O&M expenditures for the Modular Cooling Towers are expected to be $902,020 or 100% higher than originally projected. As stated in my April 2, 2012 are for reasonable storage costs for equipment associated with the permanent cooling tower.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the National Pollutant Discharge Elimination System (NPDES) Program (Project No. 16) for the period January 2012 to December 2012.

A. O&M expenditures for the NPDES Program are expected to be $419,554 or 65% lower than originally projected. This variance is primarily due to delay in work on thermal discharge studies pending authorization to proceed from the FDEP. In addition, as explained in the February 8, 2012 program update provided as Exhibit No. __ (PQW-1), the Administrative Order issued with the NPDES renewal permit for PEF's Suwannee Plant includes a new requirement that PEF did not anticipate when it filed its 2012 cost projections in August 2011. Specifically, the Administrative Order requires PEF to perform a study of copper discharges from the Suwannee Plant and, depending upon the results, may require PEF to perform additional feasibility studies to evaluate options to comply with the copper discharge limit. As required by the Order, PEF submitted a Plan of Study to FDEP in June 2012. PEF is awaiting the agency's response to the plan and will proceed with work as outlined in the Order. The cost projections for 2012 remain at $40,000 as stated in the February 8, 2012, NPDES program update.

100% natural gas as part of its previously approved Integrated Clean Air Compliance Program. This petition is provided as Exhibit No. __(PQW-2).

Q. Please explain PEF's request for recovery of costs associated with the Anclote Project.

A. As discussed in PEF's petition the EPA published new Mercury and Air Toxics Standards (MATS) for emissions of various metals and acid gases from both coal and oil-fired electric generating units (EGUs). Because the Anclote Units currently fire fuel oil above regulatory thresholds prescribed in the new rule, the units would be subject to the new MATS for oil-fired EGUs. However, PEF has determined that the most cost-effective compliance option for PEF's Anclote Units 1 and 2 is to convert the units to fire 100% natural gas. Details of the project are provided in PEF's petition and the Direct Testimony of Mr. Joel Moran.

Q. Has the Company projected the costs it will incur associated with Anclote MATS compliance?

A: As provided in Mr. Joel Moran's testimony the total expected cost of the Anclote MATS compliance project is $79.3 million.

Q. Do the new costs for which PEF seeks recovery qualify for recovery through the ECRC?

A. Yes. Costs for which PEF seeks recovery meet the requirements for ECRC recovery previously established by the Commission. Specifically, the options to comply with MATS at the Anclote Plant: install emission controls to meet the new emission limits for oil-fired units or maintain oil-firing below the heat input thresholds specified in the new rule.. As explained in PEF's March 29, 2012 petition, converting the Anclote units to fire 100% natural gas is the most reasonable and cost-effective compliance option.

Q: Please discuss PEF's 2012 costs associated with Crystal River Units 4 and 5 MATS compliance.

A: As explained in the May 14, 2012 update attached as Exhibit No. ___ (PQW-3), when PEF submitted its 2012 projects in Docket No. 110007-EI, PEF expected to incur approximately $300,000 in costs for emissions testing needed to assess mercury, particulate and acid gas emissions from Crystal River Units 4 and 5 in order to develop the Company's MATS compliance strategy for those units. Based on a review of the final MATS rule issued on December 21, 2011, as well as the results of initial emissions testing, PEF has determined that more detailed emissions testing and continuous monitoring is required to enable PEF to adequately assess potential mercury control strategies. Among other things, PEF plans to install mercury monitors that will enable the Company to develop a longer-term assessment of mercury emissions under a variety of operating conditions and control options. This longer-term assessment is necessary to ensure that potential control options can consistently achieve compliance on a 30-day rolling average basis as required under the final MATS rule. The cost of these activities is expected to be $1,250,930.

Q. Please provide an update of the Cross State Air Pollution Rule (CSAPR) issued by the EPA on July 6, 2011.

A. The CSAPR was stayed by the U.S Court of Appeals for the D.C. Circuit on December 30, 2011, leaving the Clean Air Interstate Rule (CAIR) in effect until the litigation against the CSAPR is resolved. Oral argument in that litigation was held on April 13, 2012, and a decision by the court is expected in the summer of 2012.

Q. Does this conclude your testimony?

A. Yes.

Errata to Testimony of Patricia Q. West
August 1, 2012

Page 3, Line 15: Change "Exhibit No. __ (PQW-1)" to "Exhibit No. __ (PQW-2)"

Page 3, Line 18: Change "Exhibit No. __ (PQW-2)" to "Exhibit No. __ (PQW-3)"

Page 3, Line 21: Change "Exhibit No. __ (PQW-3)" to "Exhibit No. __ (PQW-4)"

Page 5, Line 18: Change "__ (PQW-3)" to "__ (PQW-4)"

Page 7, Line 12: Change "Exhibit No. __ (PQW-1)" to "Exhibit No. __ (PQW-2)"

Page 8, Line 8: Change "Exhibit No. __ (PQW-3)" to "Exhibit No. __ (PQW-4)"

Page 9, Line 2: Change "Exhibit No. __ (PQW-2)" to "Exhibit No. __ (PQW-3)"

Page 11, Line 9: Change "Exhibit No. __ (PQW-3)" to "Exhibit No. __ (PQW-4)"

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

AUGUST 30, 2012

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, Florida, 33701.

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

A. I am employed by the Environmental Services Section of Progress Energy Florida ("PEF" or "Company") as Manager of Florida Generation Environmental Services. In that position I have responsibility to ensure that environmental technical and regulatory support is provided during the implementation of compliance strategies associated with the environmental requirements for power generation facilities in Florida.

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

A. Yes.

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

A. No. As a result of the merger with Duke Power, my responsibilities have been changed to focus on power generation operations and environmental compliance activities at the generation stations throughout the Florida region. I also represent the power generation organization in the development of compliance strategies resulting from new regulations or permitting actions. However, the changes to my duties do not impact my support of the projects listed below.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide estimates of the costs that will be incurred in the year 2013 for environmental programs that fall within the scope of my responsibilities to support PEF's power generation group. These programs include the Pipeline Integrity Management Program (Project 3), Above Ground Storage Tanks Secondary Containment Program (Project 4), Phase II Cooling Water Intake 316(b) Program (Project 6), CAIR/CAMR Peaking Program (Project 7.2), Best Available Retrofit Technology Program (BART) (Project 7.5), Arsenic Groundwater Standard Program (Project 8), Underground Storage Tank Program (Project 10), Modular Cooling Tower Program (Project 11), Thermal Discharge Permanent Cooling Tower (Project 11.1) , Greenhouse Gas Inventory and Reporting Program (Project 12), Mercury Total Daily Maximum Loads Monitoring (TMDL) (Project 13), Hazardous Air Pollutants (HAPs) Information Collection Request (ICR) Program (Project 14), Effluent Limitation Guidelines ICR Program (Project 15), National Pollutant

Discharge Elimination System (NPDES) Program (Project 16), and Mercury and Air Toxics Standards (MATS) Program (Projects 17 and 17.1).

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

A. Yes. I am co-sponsoring the following portions of Exhibit No. __ (TGF-3) to Thomas G Foster's testimony:

- 42-5P page 3 of 20 - Pipeline Integrity Management
- 42-5P page 4 of 20 - Above Ground Storage Tank Containment
- 42-5P page 5 of 20 – SO2 and NOx Emission Allowances
- 42-5P page 6 of 20 - Phase II Cooling Water Intake
- 42-5P page 7 of 20 – Clean Air Interstate Rule (CAIR)
- 42-5P page 8 of 20 – Best Available Retrofit Technology (BART)
- 42-5P page 9 of 20 - Arsenic Groundwater Standard
- 42-5P page 11 of 20 - Underground Storage Tanks
- 42-5P page 12 of 20 - Modular Cooling Towers
- 42-5P page 13 of 20 - Crystal River Thermal Discharge Project
- 42-5P page 14 of 20 - Greenhouse Gas Inventory and Reporting
- 42-5P page 15 of 20 - Mercury TMDL
- 42-5P page 16 of 20 - Hazardous Air Pollutants (HAPs) ICR Program
- 42-5P page 17 of 20 - Effluent Limitation Guidelines ICR Program
- 42-5P page 18 of 20 – National Pollutant Discharge Elimination System (NPDES)

- 42-5P page 19 of 20 – Mercury and Air Toxics Standards (MATS) Program – CR4 & CR5
- 42-5P page 20 of 20 – Mercury and Air Toxics Standards (MATS) Program – Anclote Gas Conversion

Q. What costs do you expect to incur in 2013 in connection with the Pipeline Integrity Management Program (Project 3)?

A. For 2013, PEF estimates to incur $593,000 in O&M costs to comply with the Pipeline Integrity Management (PIM) regulations (49 CFR Part 195). These costs include general program management and oversight of the performance of program activities.

Q. What costs do you expect to incur in 2013 in connection with the Above Ground Storage Tank Secondary Containment Program (Project 4)?

A. PEF does not expect any expenditures in 2013.

Q. What costs do you expect to incur in 2013 in connection with the Phase II Cooling Water Intake Program (Project 6)?

A. PEF cannot project the level of expenditures it may incur for this project in 2013; therefore, PEF has not included any such costs in its projection filing. However, as the Commission is aware, as a result of the July 17, 2012 second amendment to the settlement agreement among the U.S. Environmental Protection Agency (EPA) and plaintiffs, EPA is expected to issue a final rule establishing cooling water intake standards pursuant to Section 316(b) of the

Clean Water Act rule in June 2013. As discussed in PEF's response to FPSC's Information Request dated May 19, 2011, the proposed rule would establish standards for impingement mortality that can be achieved in either one of two ways: 1) modify traveling intake screens with fish collection and return systems that demonstrate that 88% of the fish collected will survive the process or 2) reduce the intake flow velocity to 0.5 feet per second. The proposed 316(b) rules would establish that state permitting authorities (FDEP in Florida) determine requirements for entrainment mortality on a case-by-case, site specific basis. The permittee must collect data, conduct studies and submit information that would be used by the state permitting authorities to make its decision. Permittees would also be required to include an evaluation of a closed-cycle, re-circulating cooling system (cooling towers) retrofit as part of their entrainment studies. PEF is assessing several options that may be required to comply with the rule. The options under consideration may change once the final rule is issued and its impacts better understood; therefore, the exact costs that PEF will incur under 316(b) cannot be predicted.

Q. What costs do you expect to incur in 2013 in connection with the CAIR / CAMR Program (Project 7.2)?

A. PEF expects to incur $68,100 in O&M costs for the operation and maintenance of predictive emissions monitoring systems at its combustion turbine sites. O&M costs for ongoing software vendor support of these systems are projected to be $36,500. Air emissions testing requirements are expected to be approximately $31,600 to comply with 40 CFR 75, Appendix E, Section 2.2.

This regulation requires the Company to perform testing to reset correlation curves every 20 quarters and must be performed on all of its Predictive Emissions Monitoring Systems (PEMS) between 2011 and 2013. Additional air emissions (Appendix E) testing may also be required after maintenance activities.

Q: What costs do you expect to incur in 2013 in connection with the Best Available Retrofit Technology (BART) Program (Project 7.5)?

A: PEF expects to incur approximately $16,000 in O&M costs for BART. These costs are associated with air emissions testing that is planned during the first half of 2013 to confirm CR Units 1 and 2 continue to comply with the particulate matter emissions identified in the site's BART permit (compliance must be demonstrated by October 1, 2013).

Q. What costs do you expect to incur in 2013 in connection with the Arsenic Groundwater Standard Program (Project 8)?

A. PEF expects to incur approximately $31,000 in O&M costs for the Arsenic Groundwater Standard Program to finish agency-required groundwater plan of study and submit a parameter exemption petition to the FDEP.

Q. What costs do you expect to incur in 2013 in connection with the Underground Storage Tanks Program (Project 10)?

A. PEF does not expect any expenditures in 2013.

Q. What costs do you expect to incur in 2013 in connection with the Modular Cooling Tower Program (Project 11)?

A. PEF does not expect any expenditures in 2013.

Q. What costs do you expect to incur in 2013 in connection with the Thermal Discharge Permanent Cooling Tower (Project 11.1)?

A. For informational purposes in this filing, PEF estimates 2013 capital expenditures of $209,940. These estimates may be impacted by both the final form of new environmental regulations, and the repair plan and timing of completing Crystal River 3 delamination work. As discussed in Witness Foster's testimony, none of the estimated spend is driving revenue requirements in 2013.

Q. What costs do you expect to incur in 2013 in connection with the Greenhouse Gas (GHG) Inventory and Reporting Program (Project 12)?

A. PEF does not expect any expenditures in 2013.

Q. What costs do you expect to incur in 2013 in connection with the Mercury TMDL Program (Project 13)?

A. PEF does not expect any expenditures in 2013.

Q. What costs do you expect to incur in 2013 in connection with the Hazardous Air Pollutants (HAPs) Information Collection Request (ICR) Program (Project No. 14)?

A. PEF does not expect any expenditures in 2013.

Q. What costs do you expect to incur in 2013 in connection with the Effluent Limitation Guidelines ICR Program (Project No. 15)?

A. PEF does not expect any expenditures in 2013.

Q. What costs do you expect to incur in 2013 in connection with the National Pollutant Discharge Elimination System (NPDES) Program (Project No. 16)?

A. PEF expects to incur $477,200 of O&M costs to conduct NPDES studies including thermal evaluations and whole effluent toxicity testing (WET) at the Anclote, Bartow, Crystal River and Suwannee plants, and continuation of the copper mixing zone study at the Suwannee plant. Capital expenditures in 2013 are expected to be $160,000 for completion of the corrective action plan to comply with the freeboard limitation requirement at Bartow and obtain a substantial permit modification to allow for a new surface water discharge outfall. Aquatic organism return studies and implementation have been deferred to 2014 based on FDEP's acknowledgement that the work should be conducted as required by the EPA's 316(b) rule which is now scheduled to be finalized in June 2013.

Q. What costs do you expect to incur in 2013 in connection with the Mercury and Air Toxics Standards (MATS) Program – CR4 & CR5 (Project No. 17)?

A. PEF expects to spend $10 million in capital costs in 2013 for Crystal River Units 4 and 5 MATS compliance. These costs are preliminary and PEF anticipates the installation and maintenance of continuous mercury emissions monitors on Crystal River Units 4 and 5. The costs and scope of work will be refined as PEF continues development of its compliance strategy as described in the May 14, 2012 update of PEF's Integrated Clean Air Compliance Plan and my August 1, 2012 testimony regarding Estimated / Actual projected expenditures for Docket No. 120007-EI.

Q: What costs do you expect to incur in 2013 in connection with the MATS – Anclote Gas Conversion Program (Project 17.1)?

A: PEF expects to incur $48 million in capital costs for Anclote MATS compliance in 2013 as discussed in the Direct Testimony of Mr. George Hixon.

Q. What is the status of EPA's Cross-State Air Pollution Rulemaking?

A. As discussed in PEF's Annual Review of its Integrated Clean Air Compliance Program provided as Exhibit No. __ (PQW-1) to my April 1, 2012 testimony, the U.S. Court of Appeals for the District of Columbia Circuit stayed the effect of EPA's Cross-State Air Pollution Rule (CSAPR) on December 30, 2011. This had the effect of leaving the Clean Air Interstate Rule (CAIR) in effect until the court completed its review of the new rule. Subsequently, on August 21, 2012, the Court issued an opinion that would vacate CSAPR and continue to leave CAIR in effect until EPA promulgates a valid replacement to CSAPR. Accordingly, PEF currently assumes that CAIR will stay in effect through 2013.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFF SWARTZ

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 110007-EI

April 2, 2012

Q. Please state your name and business address.

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

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

A. I am employed by Progress Energy Florida as Vice President – Power Generation Operations Florida.

Q. What are your responsibilities in that position?

A. As Vice President of PEF's Power Generation organization, my responsibilities include overall leadership and strategic direction of PEF's power generation fleet. My major duties and responsibilities include developing and implementing strategic and tactical plans to operate and maintain PEF's non-nuclear generation fleet; recommending projects and additions to the generation fleet; major maintenance programs; outage and project management; recommending retirement

COM 5
APA 1
ECR 6
GCL 1
RAD 1
SRC
ADM
OPC
CLK
CltRep 1

of generation facilities; asset allocation; workforce planning and staffing; organizational alignment and design; continuous business improvements; retention and inclusion; succession planning; overseeing hundreds of employees and hundreds of millions of dollars in assets and capital and operating budgets.

I have also assumed David Sorricks' ECRC responsibilities.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the United States Naval Academy 1985. I have 10 years of power plant and production experience in various managerial and executive positions within Progress Energy managing Fossil Steam Operations, Combustion Turbine (CT) Operations and Nuclear plant operations. While at Progress Energy, I have managed new unit projects from construction to operations, and I have extensive contract negotiation and management experience. My prior experience also includes nuclear engineering and operations experience in the United States Navy and project management, engineering, supervisory and management experience with a pulp, paper and chemical manufacturing company.

Q. What current PSC-approved projects are you responsible for?

A. I am responsible for CAIR Crystal River Project No. 7.4 O&M costs.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between actual operation and maintenance (O&M) expenditures and estimated/actual cost projections for environmental compliance costs associated with PEF's Integrated Clean Air Compliance Program for the period January 2011 through December 2011.

Q. How do the actual project expenditures for the CAIR Crystal River (Project 7.4) compare with PEF's Estimated/Actual Filing project expenditures for the period January 2011 to December 2011?

A. CAIR Crystal River O&M expenditures were $1,392,584 or 5% higher than projected in the Estimated/Actual Filing. This variance is primarily attributable to $1,423,229 higher than expected costs for CAIR Crystal River Project 7.4 – Energy.

Q. Please explain the variance between the actual project expenditures and estimated/actual projections for the CAIR Crystal River (Project No. 7.4 – Energy) for the period January 2011 to December 2011.

A. PEF's costs for reagents and by-products for 2011 were $1,423,229 or 12% higher than estimated in the Estimated/Actual Filing. This variance is attributed to higher than budgeted volumes and higher expenses for gypsum removal. In 2011, actual production of gypsum was 478,792 tons compared to a projection of 430,890 tons. Actual production exceeded the projected amount primarily due to higher actual capacity factors for Crystal River Units 4 and 5. In addition, increased production and suppressed market sales led to more gypsum being land filled than expected.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFF SWARTZ

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

AUGUST 1, 2012

Q. Please state your name and business address.

A. My name is Jeff Swartz. 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 Progress Energy Florida in the capacity of Vice President Power Generation – Florida.

Q. What are your responsibilities in that position?

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

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the United States Naval Academy in 1985. I have 11 years of power plant and production experience in various managerial and executive positions within Progress Energy managing Fossil Steam Operations, Combustion Turbine (CT) Operations and Nuclear plant operations. While at Progress Energy, I have managed new unit projects from construction to operations, and I have extensive contract negotiation and management experience. My prior experience also includes nuclear engineering and operations experience in the United States Navy and project management, engineering, supervisory and management experience with a pulp, paper and chemical manufacturing company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances for the estimated/actual operation and maintenance (O&M) expenditures and projections for environmental compliance costs associated with PEF's Integrated Clean Air Compliance Program for the period January 2012 through December 2012.

Q. What current PSC-approved projects are you responsible for?

A. I am responsible for the CAIR Crystal River Project No. 7.4 O&M and capital costs.

Q. How do the estimated/actual project expenditures for the CAIR Crystal River (Project No. 7.4) compare with PEF's projection project expenditures for the period January 2012 to December 2012?

A. PEF is projecting O&M expenditures to be approximately $7.7 million or 24% lower for this program than originally projected. This variance is primarily being driven by a $9.3 million decrease in CAIR Crystal River Project 7.4 – Energy and a $1.6 million increase in CAIR Crystal River Project 7.4 – Base.

Q. Please explain the reasons for the variance between the Estimated/Actual project expenditures and the original projections for the CAIR Crystal River (Project No. 7.4 – Energy) for the period January 2012 to December 2012.

A. The $9.3 million decrease in the project is primarily due to a $7.2 million decrease in Gypsum Disposal/Sales expense due to lower expenses than originally projected for gypsum removal as well as increased customer sales. Ammonia and limestone costs are approximately $0.9 and $1.9 million lower than originally projected due to lower than budgeted usage as a result of transitioning the Acid Mist Mitigation (AMM) system to hydrated lime. Additionally, PEF expects a $0.7 million increase in bottom/fly ash reagent expenses due to use of hydrated lime.

Q. Please explain the reasons for the variance between the Estimated/Actual project expenditures and the original projections for the CAIR Crystal River (Project No. 7.4 – Base) for the period January 2012 to December 2012.

A. The $1.6 million increase in the project is primarily attributable to costs incurred to handle the fly ash from units 4 and 5. This fly ash has elevated levels of ammonia (NH3) present and is requiring more precautionary measures to monitor and treat the ash before handling. Transitioning the AMM system to hydrated lime is mitigating this expense and should eliminate it in the long term.

Q. How do the estimated/actual project expenditures for the Crystal River CAIR Project compare with PEF's projection project expenditures for the period January 2012 to December 2012?

A. The estimated/actual total capital expenditures for the Crystal River CAIR Projects in 2012 are $22.5 million, which is approximately $5.4 million or 19% lower than PEF's 2012 Projection filing. The difference is primarily attributable to lower than projected costs for the Crystal River Unit 4 (CR4) catalyst, FGD alternative water Project, FGD blowdown treatment, and FGD lower chloride setpoint operation. The projection for the CR4 catalyst has been revised to reflect a deferral of some of the projected spends into 2013. The original projection assumed that the entire project would be completed in 2012; however, payment schedules moved some cost into 2013. The FGD alternative water project has been broken down into discrete projects with smaller scopes of work. Several of these projects are still under evaluation and undergoing engineering designs; therefore, the spending will be significantly less in 2012. Once the studies and engineering designs are complete, the implementation of the projects will resume. The FGD blowdown treatment project is also still in the planning and engineering phase. The majority of the expenditures associated with the project will take place in 2013 and/or 2014, once a final solution for compliance is determined and approved. The FGD lower chloride setpoint operation project cannot be evaluated until the outage in the late fall. Therefore, only the engineering inspections can be performed this year.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFF SWARTZ

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

AUGUST 30, 2012

Q. Please state your name and business address.

A. My name is Jeff Swartz. 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 Progress Energy Florida (PEF) in the capacity of Vice President Power Generation – Florida.

Q. Have you previously submitted testimony in this proceeding?

A. Yes.

Q. Have your responsibilities changed since you last submitted testimony in this proceeding?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide current estimates of costs that will be incurred for environmental on-going capital and operation and maintenance (O&M) expenditures for environmental compliance costs associated with PEF's Integrated Clean Air Compliance Program for the period January 2013 through December 2013.

Q. What current PSC-approved projects are you responsible for?

A. I am responsible for the CAIR Crystal River Project No. 7.4 capital and O&M costs.

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 PEF's Crystal River Clean Air Projects. I also am co-sponsoring the following portions of Exhibit No. __ (TGF-3) attached to Thomas G. Foster's testimony:

- 42-5P page 7 of 20 – Clean Air Interstate Rule (CAIR).

Q. What O&M costs do you expect to incur in 2013 in connection with the operation of the air emission controls at Crystal River Unit 4 and 5 as part of the Integrated Clean Air Compliance Program (Project 7.4)?

A. PEF estimates that approximately $27.9 million in O&M costs will be spent to support the operation and maintenance of the new air emissions controls that were installed at the Crystal River Energy Complex as outlined in the PEF Integrated Clean Air Compliance Plan. Labor costs are expected to be approximately $7.5 million. This estimate is based upon current staffing levels which were developed after review of similar operations outside of PEF as well as comparison of similar units within the Company. Administrative and General (A&G) expenses are expected to be approximately $0.2 million for incremental positions that were created to support the Integrated Clean Air Compliance Program project. Contractor expenses are expected to be approximately $3.5 million for activities such as post-construction modifications not covered by warranty, new chimney maintenance, limestone, gypsum and urea handling, cleaning of coal pond systems, additional security, gypsum sampling and analysis, truck scale maintenance, ground water monitoring and contracted equipment maintenance and repairs. Miscellaneous costs for tools and equipment, rental equipment and other employee costs are expected to be approximately $0.3 million, and parts and materials are expected to be approximately $2.2 million. CR4 outage costs are expected to be approximately $1.1 million, which includes $0.7 million of absorber work, $0.1 million of SCR and $0.3 million on the FGD auxillary support system. Expenses for FGD Blowdown pond cleanout are expected to be approximately $1.3 million. Expenses for miscellaneous projects are expected to be approximately $1.0 million for CAIR Absorber Recycle (AR) pump overhauls and major maintenance, ball mill major maintenance, dewatering system overhauls, oxidation air blower overhauls, conveyor maintenance and CR4 clinker mitigation. The clinkers are hard masses forming in the FGD inlet ducts of CR4 & 5 and are a result of the high temperature differential between the flue gas and limestone slurry. The mitigation project will install a permanent water spray system in the FGD flue gas inlet; this water system will reduce the temperature differential and thereby reduce the clinker formation. Reagent costs (net gypsum sales / disposal, limestone, urea / ammonia, and bottom / fly ash) are expected to total approximately $10.7 million.

Q. Witness Foster indicates an adjustment was included in January 2013 related to ammonia expense, can you explain why that was necessary?

A. Yes. As Mr. Foster mentions, after my prior testimony of August 1, 2012 was filed we discovered an error in how the ammonia expense for the remainder of 2012 was estimated. The estimate included for July through December was calculated using estimated consumption of ammonia on an aqueous (in liquid water solution) basis when it should have used an anhydrous (dry-basis) tonnage. This caused the 2012 estimated cost to be overstated by approximately $350 thousand. To correct for this and make our costs for 2012 and 2013 correct in aggregate we have placed a credit in this amount in January 2013.

Q. Are there any ongoing capital costs in 2013 associated with the implementation of the Integrated Clean Air Compliance Program (Project 7.4)?

A. Yes. PEF estimates that $4.7 million in capital costs will be incurred as part of the Integrated Clean Air Compliance Program in 2012. Such costs include:

- Purchase and installation of a third layer of catalyst for the SCR's which are necessary to maintain the removal efficiency of the SCR system.

- Development and engineering of an alternative wastewater system for FGD blowdown treatment which is needed to comply with FDEP wastewater permit conditions.
- Development and engineering of a reclaimed water reuse system, an alternative water project, to comply with the Conditions of Site Certification requirements regarding the rolling annual average daily withdrawal rate of groundwater from the CR4&5 well field.

Q. What steps is the Company taking to ensure that the level of expenditures for the operation of the Crystal River 4 and 5 controls is reasonable and prudent?

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

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

A. The Company has established a dedicated unit to manage, operate and maintain the CAIR equipment. An organization chart is attached in Exhibit_(JS-1). This unit consists of 52 employees and reports to the Crystal River plant manager and one employee who reports to the Manager of PEF Generation Finance. There are

8 managers, 25 operations employees and 20 maintenance employees. The operators work rotating shifts in order to staff the operations of the facility 24 hours per day. The maintenance employees primarily work days but are available for emergent work after normal hours. In an effort to keep regular staffing levels lower, contractors are used for specialized or lower-skilled work. This minimizes overall operations and maintenance costs.

Q. Are there policies and procedures in place to efficiently operate and maintain these assets?

A. Yes, there are several different policies and procedures the plant uses to efficiently operate and maintain the CAIR equipment. First and foremost, the plant follows all OSHA and Progress Energy safety-related policies and procedures. It also uses operating procedures to efficiently operate equipment 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. In addition, equipment is maintained using equipment-specific preventive maintenance procedures. The operating and maintenance procedures were developed during construction and startup, and will continue to be revised as more experience and expertise is gained with the equipment.

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

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

A. The personnel selected to operate and maintain CAIR equipment have to meet specific job-related qualifications in order to qualify for the positions they are selected to perform. Some employees are hired from outside companies and came to Progress Energy with previous experience operating this type equipment at other utilities. Other operations employees are selected to participate in an 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 the employee progress through different levels of task proficiency. Maintenance employees are selected based on their skills and experience.

Equipment-specific training was accomplished during the construction and start-up phase of the project. 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 these policies and procedures using several different training methods that include reading and review of the policies and procedures, small group discussions, one-on-one discussions with subject matter experts, computer based training (CBT) and on the job training.

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

A. The Company ensures compliance with policies and procedures through management controls, self-checks, use of checklists, procedure sign-offs and 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 these assets?

A. Along with the above-mentioned methods, prudent engineering judgment and industry standards are used to ensure proper operations and maintenance of CAIR equipment.

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 this equipment.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JOEL MORAN

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

AUGUST 1, 2012

Q. Please state your name and business address.

A. My name is Joel Moran. My business address is P.O. Box 1551, Raleigh, NC 27602.

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

A. I am employed by Progress Energy Carolina (PEC) as Manager of Project Engineering in the Energy Supply division under the New Generation Projects and Programs (NGPP) group.

Q. What are your responsibilities in that position?

A. My responsibilities include major project planning and execution. My primary duties involve the management of engineering activities to ensure project scoping is accurate and complete, provide input to estimate development, assist in the development of project execution and contracting strategies, and provide input to the overall project schedules. These duties are relevant to projects that emerge from system planning and environmental planning activities where specific projects are identified as viable projects that will move forward into funding, contracting, design, construction, and startup phases. Our group generally accommodates projects in excess of $50 million dollars in value. The NGPP section also will lead and execute programs as needed.

Q. Please describe your educational background and professional experience.

A. I earned a BS in Mechanical Engineering from North Carolina State University in 1983 and a MS in Mechanical Engineering from Georgia Institute of Technology in 1988. I have been registered in the state of North Carolina as a Professional Engineer since 1989 and am also registered in the state of South Carolina. In addition, I am a certified Project Management Professional. Prior to employment with Progress Energy, I worked for major national architectural/engineering (A/E) firms on firm price power generation projects both domestic and internationally. These projects included both new generation and environmental retrofit projects. Project work with Progress Energy includes engineering management oversight for environmental retrofit projects and new generation projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide background and explanation for the cost and scope of the Anclote Gas Conversion Project (Project 17.1).

Q. What has been your role in the Anclote Gas Conversion Project?

A. I served as the initial Project Manager for the Anclote Gas Conversion Project since its inception, although we are in the process of transitioning to a new Project Manager. As the initial project manager, I was responsible for reviewing the initial engineering studies, schedules, and estimates to ensure the project is accurately defined and an adequate timeline for the execution of the project had been allocated. In addition, I worked with others in the organization to secure project approval and funding, lead internal contract planning and strategy efforts, and worked with supply chain to contract the boiler modification work and the balance of plant engineering services. I continue to have direct involvement in the project as it is transitioned to another Project Manager. As a result, I have personal knowledge of the current status of the project and associated engineering activities.

Q Please describe the management structure being used to oversee implementation of the Anclote Project.

A. Our management structure for execution of major projects relies on a matrix organizational structure. The Project Manager directs a team that consists of a Project Engineer (or Engineering Manager), a team of engineering discipline leads (e.g., mechanical, electrical, civil/structural, etc.), a Quality Manager, and various supply chain specialists and other personnel who report to functional managers.

The Engineering Manager provides direction to the engineering discipline leads with regard to the technical oversight of the engineering effort for the project. The Engineering Manager addresses technical concerns related to the scope of the project, oversees the general engineering progress for the job, and keeps the Project Manager apprised of technical issues that affect cost, schedule, or quality.

The engineering discipline leads are responsible for the technical evaluation of the design of the project. They assure technical compliance with the contracts and provide technical guidance to the team where areas of the technical specifications are not clear or have been omitted.

The Quality Manager provides input and oversight of the engineering, equipment supplier, and the construction contractor's QA/QC practices and procedures. The QA Manager provides input to the Test & Inspection plans related to the project that protect the interests of the Company and end user ensuring the quality is consistent with company standards and good engineering practice. The QA Manager ensures technical requirements of relevant codes and project technical specifications are maintained.

The supply chain specialists assist the Project Manager and project team in the competitive bidding of the equipment and services required of the project. They provide commercial input to contracts with the interest of protecting the

Company from adverse terms and conditions that would otherwise introduce business risk in excess of the Company's normal practice.

Q. What are the estimated costs associated with the Anclote Gas Conversion Project?

A. The Company currently estimates total project costs of approximately $79.3 million. This estimate could change depending on the results of an ongoing engineering evaluation that the Company is conducting to determine whether and the extent to which the project will necessitate changes to the Anclote units' forced draft (FD) fan systems.

Q. How much of the total project costs does the Company expect to incur in 2012?

A. We currently expect to incur approximately $22 million of costs for the project in 2012. Such costs will be incurred for: permitting activities; balance-of-plant (BOP) detailed engineering services; BOP engineered equipment procurement; boiler controls engineering; procurement of boiler equipment, materials, and components needed to convert Unit 1 and associated engineering; securing a contractor for the installation services required to complete the construction for both units in 2013; and detailed engineering and procurement of components needed to modify and upgrade the natural gas metering and regulating station.

Q. What steps is the Company taking to ensure that the level of expenditures for the Anclote Gas Conversion Project is reasonable and prudent?

A. PEF developed a phased contracting and procurement strategy to mitigate project risks and to ensure that project expenditures are reasonable and prudent. Following completion of initial study evaluations, PEF issued a competitive solicitation to major boiler original equipment manufacturers (OEMs) for boiler modification engineering ("Phase 1") and boiler pressure part supply ("Phase 2"). The boiler modification engineering (Phase 1) includes thermal design, emissions estimates, performance predictions, vibration analysis, furnace draft evaluation, control evaluation, and budgetary equipment and engineering pricing. The boiler pressure part supply (Phase 2) includes procurement of boiler tubes, headers, valves, burners, burner management system logic, and other related equipment and materials.

Phase 1 and Phase 2 were bid at the same time, but PEF awarded the Phase 1 contract first to allow the Phase 2 scope to be refined through the Phase 1 engineering. In order to ensure competitive equipment pricing, the Phase 1 contract included a pricing commitment from the OEM supplier on Phase 2 scope based on a defined scope included in the initial request for proposals that would serve as a basis for the cost evaluation of the final engineering solution. Due to scope synergies and scope interface between engineering and boiler pressure part supply, PEF ultimately awarded the Phase 2 contract to the same OEM that performed the engineering evaluation for Phase 1. After completion of the Phase 1 engineering work, PEF competitively bid and awarded the balance of plant (BOP) engineering. The installation/demolition work will be competitively bid in the Fall of 2012 once the detailed engineering is sufficiently complete. PEF decided to bid the boiler pressure parts supply (Phase 2) separately from the installation/demolition scope to maintain the integrity of multiple OEM bidders for pressure parts (i.e., not to disqualify those without install/demo capabilities) and to allow time for the installation/demolition scope to be better defined.

Q. How long will the Anclote Gas Conversion Project take to complete and when is its targeted in-service date?

A. Delivery of OEM pressure parts for Unit 1 will be completed by mid-February of 2013. The Unit 1 outage to install these components will be completed second quarter 2012 at which time the Unit 1 conversion will be put in service. The delivery of the Unit 2 boiler components will be completed by mid-August 2013. The Unit 2 conversion outage will be complete and the unit returned to service by fourth quarter 2013.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

GEORGE HIXON

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

AUGUST 31, 2012

Q. Please state your name and business address.

A. My name is George Hixon. My business address is 15760 W Powerline St., Crystal River, FL 34428.

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

A. I am employed by Progress Energy Florida (PEF) as Manager of Major Projects in the Energy Supply division under the Project Management and Construction (PMC) group.

Q. What are your responsibilities in that position?

A. My responsibilities include major project planning and execution, including oversight, construction, commissioning, and start up of project. My primary duties involve the management of engineering activities to ensure project scoping is accurate and complete, provide input to estimate development, assist in the development of project execution and contracting strategies, and provide input to the overall project schedules. These duties are relevant to projects that emerge from system planning and environmental planning activities where specific projects are identified as viable projects that will move forward into funding, contracting, design, construction, and startup phases. Our group generally accommodates projects in excess of $50 million in value. The PMC section also will lead and execute programs, as needed.

Q. Please describe your educational background and professional experience.

A. I earned a BS in Civil Engineering from Clemson University in 1971. I have been registered in the state of South Carolina as a Professional Engineer since 1981. Prior to my employment with Progress Energy, I worked for different construction and engineering firms in the United States ranging from a Field Engineer and advancing to a Vice President/Project Manager. These projects included managing major engineering design and construction projects in the Pulp and Paper, Power and Heavy Industrial, and Cement plant construction markets both domestically and internationally. In 2001, I became employed with Calpine Corporation as a Senior project Manager where I managed several gas turbine and steam turbine projects. In May 2005, I was hired by Progress Energy where I oversee the construction, commissioning and start up of projects. Project work with Progress Energy includes engineering management oversight for environmental retrofit projects and repowering projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide background and explanation for the cost and scope of the Anclote Gas Conversion Project (Project 17.1).

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

A. Yes. I am co-sponsoring the following portions of Exhibit No. __ (TGF-3) to Thomas G Foster's testimony:

- 42-5P page 20 - Mercury & Air Toxic Standards (MATS) (Anclote Gas Conversion)

Q. What has been your role in the Anclote Gas Conversion Project?

A. I transitioned into the role as the Project Manager for the Anclote Gas Conversion Project. I worked with Mr. Joel Moran, the initial Project Manager, to ensure an efficient transition. I am responsible for overall construction management oversight and reviewing the engineering studies, schedules, and estimates to ensure the project is accurately defined and an adequate timeline for the execution of the project is allocated. In addition, I work with others in the organization to lead internal contract planning and strategy efforts and work with supply chain to contract the boiler modification work and the balance of plant engineering services.

Q Have you reviewed the testimony of Joel Moran, filed in this docket on August 1, 2012?

A. Yes, I have reviewed that testimony.

Q In that testimony, Mr. Moran described the management structure used to oversee implementation of the MATS - Anclote Gas Conversion Project. Does that structure remain the same?

A. Yes, the management structure is the same.

Q. What are the estimated costs associated with the Anclote Gas Conversion Project?

A. The Company currently estimates total project costs of approximately $79.3 million.

Q. What costs do you expect to incur in 2013 in connection with the MATS – Anclote Gas Conversion Project?

A. We currently expect to incur approximately $48 million of costs for the project in 2013. Such costs will be incurred for: initial contractor mobilization; permitting activities; balance-of-plant (BOP) detailed engineering services; BOP engineered equipment procurement; boiler controls engineering; procurement of boiler equipment, associated engineering, materials, and components needed to complete conversion of Unit 1 and Unit 2; securing a contractor for the installation services required to complete the construction for both units in 2013; and detailed engineering and procurement of components needed to modify and upgrade the natural gas metering and regulating station.

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

A. Yes, we continue to expect that the Unit 1 conversion will be put into service second quarter 2013 and that the Unit 2 conversion outage will be complete and the unit returned to service by fourth quarter 2013.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

COREY ZEIGLER

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

April 2, 2012

Q. Please state your name and business address.

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

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

A. I am employed by Progress Energy Florida (PEF) as Manager, Environmental Services and Strategy for Delivery and Services.

Q. What are your responsibilities in that position?

A. Currently, my responsibilities include managing environmental permitting and compliance activities for Energy Delivery Florida. Energy Delivery Florida is part of the Florida Distribution Business unit of which I support the Distribution, Transmission Operations and Planning, and the Corporate Services Departments.

COM 5
APA 1
ECR 6
GCL 1
RAD 1
SRC
ADM
OPC
CLK
Ct Rep 1

Q. Please describe your educational background and professional experience.

A. I received a Bachelors of Science degree in General Business Administration and Management from the University of South Florida. Prior to my current role, I was the Health and Safety Manager for Progress Energy Florida Transmission and Delivery. I have 20 years experience in the utility industry holding various operational, supervisor and managerial roles at Progress Energy.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between the actual project expenditures versus the estimated/actual project expenditures for environmental compliance costs associated with PEF's Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Project 1 & 1a) and the Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2).

Q. How did actual O&M expenditures for January 2011 through December 2011 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits for the Substation System Program?

A. The project expenditure variance for the Substation System Program was $1,620,074 or 20% higher than projected. The variance is attributed to higher amounts of subsurface contamination encountered during remediation of sites than was re-projected in the estimated/actual filing. PEF notes that the extent and depth of subsurface contamination can only be determined when the site is excavated. Furthermore, the amount of soil that needs to be removed to achieve FDEP clean-up target levels depends upon the results of tests conducted in the field as the remediation is conducted. As work proceeds, PEF updates unit cost estimates based upon actual invoices received from contractors.

Q. How did actual O&M expenditures for January 2011 through December 2011 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits for the Distribution System Program?

A. The project expenditure variance for the Distribution System Program was $39,367 or 1% higher than projected. The variance is attributed to unpredictability of conditions at each abatement location.

Q. Does this conclude your testimony?

A. Yes.

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

CORLEY ZEIGLER

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

AUGUST 1, 2012

Q. Please state your name and business address.

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

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

A. I am employed by Progress Energy Florida (PEF) as Manager, Environmental Permitting & Compliance.

Q. What are your responsibilities in that position?

A. My responsibilities include managing environmental permitting and compliance activities for Energy Delivery Florida. Energy Delivery Florida is part of the Florida Distribution business unit of which I support the Distribution and Transmission Operation and Planning Departments.

Q. Please describe your educational background and professional experience.

A. I received a Bachelors of Science degree in General Business Administration & Management from the University of South Florida. Prior to my current position with PEF, I was the Health and Safety Manager for PEF's Delivery and Transmission Operations and Planning Departments. I have 20 years experience in the utility industry, holding various operational, supervisor and managerial roles at Progress Energy.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between 2012 Estimated/Actual project expenditures versus original 2012 cost projections for environmental compliance costs associated with the FPSC-approved environmental programs under my responsibility. These programs include PEF's Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Projects 1 & 1a), Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2) and Sea Turtle – Coastal Street Lighting (Project 9).

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Substation Environmental Investigation, Remediation, and Pollution Preventions Program (Project 1 & 1a) for the period January 2012 to December 2012.

A. O&M project expenditures for the Substation System Program are estimated to be $1,161,514 or 28% higher than originally projected. This increase is primarily attributable to several sites that had significantly higher amounts of subsurface contamination encountered during remediation that was not evident during the original visual environmental inspections. Because most contamination is below ground, it is difficult to determine remediation costs at substation sites until the remediation process actually begins. Although visible inspections provide some indication of the potential amount of contamination, the areal extent and depth of subsurface contamination can only be determined when the site is excavated. Furthermore, the amount of soil that needs to be removed to achieve Florida Department of Environmental Protection (FDEP) clean-up target levels depends upon the results of tests conducted in the field as the remediation is conducted. As work proceeds, PEF updates cost estimates based upon actual invoices received from contractors.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2) for the period January 2012 to December 2012.

A. O&M project expenditures for the Distribution System Program are estimated to be $190,394 or 58% higher than originally projected. This increase is primarily attributable to 5 transformer sites planned for abatement work in 2011 but postponed until 2012 due to customer requests, and delayed submittal of invoices to PEF by vendors in 2012 for payment of abatement work completed in 2011.

Q: Please explain the variance between Estimated/Actual project expenditures and the original projections for the Sea Turtle – Coastal Street Lighting Program (Project No. 9) for the period January 2012 to December 2012.A:

A: O&M project expenditures for the Sea Turtle – Coastal Street Lighting Program are estimated to be $2,496 or 50% lower than originally projected. This variance is due to installing amber shields on a smaller quantity of street lights to prevent turtle disorientation than initially anticipated. PEF is notified by municipalities or the public when a turtle nesting site is close to a streetlight that currently does not have a shield in place. As a result of previously performed retrofitting, PEF is receiving fewer new requests for amber shield installations.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

COREY ZEIGLER

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

AUGUST 30, 2012

Q. Please state your name and business address.

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

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

A. I am employed by Progress Energy Florida as the Environmental Health & Safety Manager for Transmission & Distribution

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

A. Yes.

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

A. Some of my duties have changed since the last time I filed testimony, but at this time, my duties have not changed with respect to the ECRC programs that are the subject of my testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide estimates of costs that will be incurred in the year 2013 for Progress Energy Florida's (PEF's or Company's) Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a), previously approved in PSC Order No. PSC-02-1735-FOF-EI, Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2), previously approved in PSC Order No. PSC-02-1735-FOF-EI, and the Sea Turtle Coastal Street Lighting Program (Project 9), previously approved in PSC Order No. PSC-05-1251-FOF-EI.

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

A. Yes. I am co-sponsoring the following portions of the schedule Exhibit No._(TGF-3) attached to Thomas G. Foster's testimony:

- 42-5P page 1 of 20 - Substation Environmental Investigation, Remediation, and Pollution Prevention
- 42-5P page 2 of 20 - Distribution System Environmental Investigation, Remediation, and Pollution Prevention; and

- 42-5P page 10 of 20 - Sea Turtle - Coastal Street Lighting.

Q. What costs do you expect to incur in 2013 in connection with the Substation System Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a)?

A. PEF estimates O&M remediation costs of approximately $2.3 million at 34 sites for the Substation System Investigation, Remediation and Pollution Prevention Program.

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

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

Q. What costs do you expect to incur in 2013 in connection with the Distribution System Investigation, Remediation and Pollution Prevention Program (Project 2)?

A. PEF estimates O&M costs of approximately $0.2 million to perform further testing and remediation at nine sites for the Distribution System Investigation, Remediation and Pollution Prevention Program. This estimate assumes seven 3-

phase transformer sites at an average cost of $15,800 per site, two single-phase transformer sites at an average cost of $10,800 per site and deviation sampling costs of $1,000 per site. The average cost per site was based upon PEF's analysis of the prior two years of invoices associated with the remediation of transformer sites.

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

A. To ensure the level of expenditures is reasonable and prudent, PEF closely monitors remediation work and provides quarterly reports to the FDEP on progress made in remediating sites.

Q. What costs do you expect to incur in 2013 in connection with the Sea Turtle/Street Lighting Program (Project No. 9)?

A. PEF estimates capital and O&M expenses of approximately $5,000 for the Sea Turtle/Street Lighting Program to ensure compliance with sea turtle ordinances in Franklin, Gulf and Pinellas Counties and the City of Mexico Beach.

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

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

WILL GARRETT

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

April 2, 2012

Q. Please state your name and business address.

A. My name is Will Garrett. 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 Progress Energy Service Company, LLC as Controller of Progress Energy Florida (PEF).

Q. What are your responsibilities in that position?

A. As legal entity Controller for PEF, I am responsible for all accounting matters that impact the reported financial results of this Progress Energy Corporation entity. I have direct management and oversight of the employees involved in PEF Regulatory Accounting, Property Plant and Materials Accounting, and PEF Financial Reporting and General Accounting.

COM 5
APA 1
ECR 6
GCL 1
RAD 1
SRC
ADM
OPC
CLK
Crt Rep 1

Q. Please describe your educational background and professional experience.

A. I joined the company as Controller of PEF on November 7, 2005. My direct relevant experience includes over 2 years as the Corporate Controller for DPL, Inc. and its major subsidiary, Dayton Power and Light, headquartered in Dayton, Ohio. Prior to this position, I held a number of finance and accounting positions for 8 years at Niagara Mohawk Power Corporation, Inc. (NMPC) in Syracuse, New York, including Executive Director of Financial Operations, Director of Finance and Assistant Controller. As the Director of Finance and Assistant Controller, my responsibilities included regulatory proceedings, rates, financial planning, and providing testimony on a variety of matters before the New York Public Service Commission. Prior to joining NMPC, I was a Senior Audit Manager at Price Waterhouse (PW) in upstate New York, with 10 years of direct experience with investor owned utilities and publicly traded companies. I am a graduate of the State University of New York in Binghamton, with a Bachelor of Science in Accounting and I am a Certified Public Accountant in the State of New York.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida'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, Progress Energy Florida's Actual True-up costs associated with Environmental Compliance activities for the period January 2011 through December 2011.

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

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

Exhibit No. WG-1 consists of the following:

- Form 42-1A reflects the final true-up for the period January 2011 through December 2011.
- Form 42-2A reflects the final true-up calculation for the period.
- Form 42-3A reflects the calculation of the interest provision for the period.
- Form 42-4A reflects the calculation of variances between actual and estimated/actual costs for O&M activities.
- Form 42-5A presents a summary of actual monthly costs for the period of O&M activities.
- Form 42-6A reflects the calculation of variances between actual and estimated/actual costs for Capital Investment Projects.
- Form 42-7A presents a summary of actual monthly costs for the period for Capital Investment Projects.

- Form 42-8A, pages 1 through 16, consist of the calculation of depreciation expense, property tax expense, and return on capital investment for each project that is being recovered through the ECRC.
- Form 42-9A presents PEF's capital structure and cost rates.

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

- Pipeline Integrity Management (Capital Program Detail (CPD), pages 1 through 2)
- Above Ground Storage Tank Secondary Containment (CPD, pages 3 through 8)
- Clean Air Interstate Rule (CAIR) Combustion Turbines (CTs)(CPD, pages 9 through 12)
- CAIR (CPD, pages 13 through 20)
- Thermal Discharge Permanent Cooling Tower (CPD, page 21)

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

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

Q. What is the final true-up amount for which PEF is requesting for the period January 2011 through December 2011?

A. PEF is requesting approval of an over-recovery amount of $863,786 for the calendar period ending December 31, 2011. This amount is shown on Form 42-1A, Line 1.

Q. What is the net true-up amount PEF is requesting for the January 2011 through December 2011 period which is to be applied in the calculation of the environmental cost recovery factors to be refunded/recovered in the next projection period?

A. PEF has calculated and is requesting approval of an under-recovery of $1,688,551 reflected on Line 3 of Form 42-1A, as the adjusted net true-up amount for the January 2011 through December 2011 period. This amount is the difference between the actual over-recovery amount of $863,786 and the actual/estimated over-recovery of $2,552,337, as approved in Order PSC-11-0553-FOF-EI, for the period of January 2011 through December 2011.

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

A. Yes.

Q. How did actual O&M expenditures for January 2011 through December 2011 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits?

A. Form 42-4A shows that total O&M project variance was $1,995,909 or 4% higher than projected. Following are variance explanations for those O&M projects with significant variances. Individual project variances are provided on Form 42-4A.

<u>O&M Project Variances</u>

1. **Substation Environmental Investigation, Remediation, and Pollution Prevention (Project No. 1):** The project expenditure variance was $1,620,074 or 20% higher than projected. This variance is primarily attributable to higher amounts of subsurface contamination encountered during remediation of sites. This project is further discussed in Corey Zeigler's Direct Testimony.

2. **Distribution System Environmental Investigation, Remediation, and Pollution Prevention (Project No. 2):** The project expenditure variance was $39,367 or 1% higher than projected. This increase is due to unpredictability of conditions at each abatement location. This project is also discussed in Corey Zeigler's Direct Testimony.

3. **Pipeline Integrity Management (Project No. 3):** The project expenditure variance was $217,985 or 14% lower than projected. This variance is primarily

attributable to work originally planned for 2011 being postponed into 2012 while the PIM team addressed sinkhole mitigation efforts. This project is further discussed in Patricia West's Direct Testimony.

4. **SO2/NOx Emissions Allowances (Project No. 5):** SO2/NOx Emissions Allowances O&M expenditures variance was $278,095 or 5% higher than in the Estimated/Actual Filing. This variance is due to a higher energy demand, due to weather, during the third quarter of 2011 and the mix of generating units dispatched.

5. **CAIR Combustion Turbine Predictive Emissions Monitoring Systems (Project No. 7.2):** The project expenditure variance was $32,164 or 27% lower than projected. This decrease is attributable to reduced costs for software maintenance and a lower number of recertification tests than were originally expected as discussed in Patricia West's Direct Testimony.

6. **CAIR Crystal River (Project 7.4):** The project expenditure variance was $1,392,584 or 5% higher than projected. This variance is primarily due to higher gypsum volumes and removal expenses than estimated. This project is further discussed in Jeff Swartz' Direct Testimony.

7. **Modular Cooling Towers (Project No. 11):** The project expenditure variance was $481,521 or 15% lower than projected. These costs were expected for demobilization dismantlement activities in November and December 2011, however, the towers were not dismantled and associated costs were not incurred as discussed in Patricia West's direct testimony.

8. **Mercury TMDL (Project No. 13):** The project expenditure variance was $11,663 or 23% lower than projected. This variance is due to Florida Coordinating Group project participation assessment fees not charged to the program as originally expected as discussed in Patricia West's Direct Testimony.

9. **National Pollutant Discharge Elimination System (Project No.16):** The project was $505,123 or 78% lower than projected. This variance is primarily attributable to a delays in the engineering studies associated with the Bartow plant's freeboard project and implementation of toxicity testing required by the Crystal River North NPDES permit as discussed in Patricia West's Direct Testimony.

10. **Mercury & Air Toxics Standards (MATS) (Project No. 17):** The project was $85,000 or 100% lower than projected. This variance is due to test reports not being finalized and available until December 2011. These costs will be

incurred in 2012 as discussed in Patricia West's Direct Testimony.

Q. How did actual Capital recoverable expenditures for January 2011 through December 2011 compare with PEF's Estimated/Actual projections as presented in previous testimony and exhibits?

A. Form 42-6A shows that Total Capital Investment Activities - Recoverable Costs variance was $137,628 lower than projected for an immaterial difference. Actual costs and variances by individual project are on Form 42-6A. Return on capital investment, depreciation and property taxes for each project for the period are provided on Form 42-8A, pages 1 through 16.

Q. Were any major CAIR assets placed into service during 2011?

A. No.

Q. Does this conclude your testimony?

A. Yes.

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

THOMAS G. FOSTER

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

AUGUST 1, 2012

Q. Please state your name and business address.

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

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

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

Q. What are your responsibilities in that position?

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

Q. Please describe your educational background and professional experience.

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, Progress Energy Florida's Estimated/Actual True-up costs associated with Environmental Compliance activities for the period January 2012 through December 2012.

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

A. Yes. I am sponsoring the following exhibits:

1. Exhibit No. __ (TGF-1), which consists of PSC Forms 42-1E through 42-9E; and
2. Exhibit No. __ (TGF-2), which provides details of capital projects by site.

These forms provide a summary and detail of the Estimated/Actual True-up Operation and Maintenance (O&M) and Capital Environmental costs and revenue requirements for the period January 2012 through December 2012.

Q. What is the Estimated/Actual True-up amount for which PEF is requesting recovery for the period of January 2012 through December 2012?

A. The Estimated/Actual True-up amount for 2012 is an over-recovery, including interest, of $14,632,974 as shown in Exhibit No. __ (TGF-1), Form 42-1E, Line 4. This amount will be added to the final true-up under-recovery of $1,688,551 for 2011 shown on Form 42-2E, Line 7a, resulting in a net over-recovery of $ 12,944,423 as shown on Form 42-2E, Line 11. The detailed calculations supporting the estimated true-up for 2012 are contained in Forms 42-1E through 42-8E.

Q. What capital structure, components and cost rates did Progress Energy Florida rely upon to calculate the revenue requirement rate of return for the period January 2012 through December 2012?

A. The capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return for the period January 2012 through

December 2012 are shown on page 42-9E. Page 42-9E 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 included in Exhibit TGF-1. The schedule also cites all sources and includes the rationale for using the particular capital structure and cost rates.

Q. How do the Estimated/Actual O&M expenditures for January 2012 through December 2012 compare with original projections?

A. Form 42-4E shows that total O&M project costs are projected to be approximately $9.3 million or 20% lower than originally projected. Following are variance explanations for those O&M projects with significant variances. Individual project variances are provided on Form 42-4E.

<u>O&M Project Variances</u>:

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

   O&M project expenditures for the Substation System Program are estimated to be approximately $1.2 million or 28% higher than originally projected. As discussed in the testimony of Mr. Corey Zeigler, this variance is primarily attributable to higher amounts of subsurface contamination encountered at the remediation sites.

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

PEF is projecting O&M expenditures to be approximately $0.2 million or 58% higher for this program than originally projected. This variance is discussed in the testimony of Mr. Corey Zeigler.

3. Emissions Allowances (Project 5) – O&M

Sulfur dioxide (SO2) and nitrogen oxide (NOx) emission allowance expenses are estimated to be approximately $3.1 million or 42% lower than originally projected. This variance is primarily driven by the fact that CSAPR was stayed in December of 2011. As PEF advised in a letter to the Commission dated January 9, 2012, due to Cross State Air Pollution Rule (CSAPR) being stayed, the NOx inventory was not written off in 2011 and the 3 year amortization the Commission approved last year was not necessary as the allowances still have value. Consistent with Order No. PSC-11-0553-FOF-EI PEF, has continued to comply with CAIR by continuing to expense NOx allowances based on actual usage in 2012 and this has resulted in a decrease in expense as compared to the projected expense based on a 3 year amortization of the remaining balance.

4. CAIR Crystal River - Energy (Project 7.4) – O&M

Total O&M project costs are estimated to be approximately $7.7 million or 24% lower than originally projected. As further discussed in the testimony of Mr. Jeffrey Swartz, this variance is primarily being driven by a $9.3 million decrease in CAIR Project 7.4 – Energy and a $1.6 million increase in CAIR Project 7.4 – Base.

5. Modular Cooling Towers – Base (Project 11) – O&M

Total O&M project costs are estimated to be approximately $0.9 million or 100% higher than originally projected. As further discussed in the testimony of Ms. Patricia West, this variance is primarily due to the removal of the cooling towers deferred from 2011 to 2012.

6. National Pollutant Discharge Elimination System - Energy (Project 16) – O&M

Total O&M project costs are estimated to be approximately $0.4 million or 65% lower than originally projected. As further discussed in the testimony of Ms.West, this variance is primarily due to delay in work on thermal discharge studies pending authorization to proceed from the Florida Department of Environmental Protection (FDEP).

7. Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy (Project 17) – O&M

Total O&M project costs are estimated to be approximately $0.3 million or 94% lower than originally projected. Ms. West describes the driver of this variance in her testimony.

Q. How do the Estimated/Actual Capital recoverable investments for January 2012 through December 2012 compare with PEF's original projections?

A. Total recoverable capital investments itemized on Form 42-6E, are projected to be approximately $3.4 million or 2% lower than originally projected. Below are variance explanations for those approved Capital Investment Projects with significant variances. Individual project variances are provided on Form 42-6E. Return on Capital Investment, Depreciation and Taxes for each project for the Estimated/Actual period are provided on Form 42-8E, pages 1 through 18.

__**Capital Investment Project Variances – Recoverable Costs:**__

1. CAIR (Project 7.x) – Capital

PEF is projecting capital investment activities to be approximately $3.4 million or 2% lower for this program than originally projected. This variance is primarily attributable to lower than projected average investment in project 7.4 and lower than projected depreciation expense due to the unitization of the project 7.4 assets.

2. SO2/NOx Emmissions Allowances (Project 5)

PEF is projecting these costs to be approximately $0.1million or 5% higher than originally projected due to higher than projected average investment balance. This is due to less amortization of the NOx investment balance than projected due to Cross State Air Pollution Rule (CSAPR) beign stayed in 2011. Ms. West describes the status of CSAPR further in her testimony.

3. National Pollutant Discharge Elimination System (NPDES) (Project 16) - Capital

PEF is projecting capital investment activities to be approximately $0.1 million or 72% lower for this program than originally projected. This project is further discussed in the testimony of Ms. West.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

THOMAS G. FOSTER

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 120007-EI

Revised OCTOBER 17, 2012

Q. Please state your name and business address.

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

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

A. I am employed by Progress Energy Service Company, LLC, as Manager of Retail Riders and Rate Cases in Florida.

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

A. Yes.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, Progress Energy Florida's (PEF's) calculation of revenue requirements and ECRC factors for customer billings for the period January 2013 through December 2013. My testimony addresses capital and operating and maintenance ("O&M") expenses associated with PEF's environmental compliance activities for the year 2013.

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

A. Yes. I am sponsoring the following exhibits:

1. Exhibit No. __(TGF-3R), which consists of PSC Forms 42-1P through 42-8P; and
2. Exhibit No. __(TGF-4), which provides details of capital projects by site.

The following individuals will also be co-sponsors of Forms 42-5P pages 1 through 20 as indicated in their testimony:

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

Q. What is the total recoverable revenue requirement relating to the projection period January 2013 through December 2013?

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is approximately $182.6 million as shown on Form 42-1P, Line 5 of Exhibit No. __(TGF-3R).

Q. What is the total true-up to be applied in the period January 2013 through December 2013?

A. The total true-up applicable for this period is an over-recovery of approximately $12.9 million. This consists of the final true-up under-recovery of approximately $1.7 million for the period from January 2011 through December 2011 and an estimated true-up over-recovery of approximately $14.6 million for the current period of January 2012 through December 2012. The detailed calculation supporting the 2012 estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. __ (TGF-1) filed with the Commission on August 1, 2012.

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

A. The following projects were previously approved by the Commission:

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

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

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

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

PEF's Integrated Clean Air Compliance Plan (Program No.7), which the Commission approved as a prudent and reasonable means of complying with CAIR and related regulatory requirements in Order No. PSC-07-0922-FOF-EI.

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

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

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

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

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

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

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

Mercury & Air Toxic Standards (MATS) (No. 17) which replaces Maximum Achievable Control Technology (MACT) was previously approved in Order No. 11-0553-FOF-EI and Order No. PSC-12-0432-PAA-EI. These programs are further discussed in Witnesses West and Hixon testimony.

Q. What impact does the Thermal Discharge Permanent Cooling Tower (No. 11.1) have on 2013 estimated costs?

A. As discussed in Witness West's testimony, these estimates will be impacted by both the final form of new environmental regulations, and the repair plan and timing of completing the Crystal River 3 delamination work. There are no revenue requirements being driven by items in CWIP for this project included in this filing.

Q. **What capital structure, components and cost rates did Progress Energy Florida rely upon to calculate the revenue requirement rate of return for the period January 2013 through December 2013?**

A. PEF has used the capital structure, components and cost rates consistent with the language in Order No. PSC-12-0425-PAA-EU. For investments other than PEF's Project 7.4 CAIR investments expected to be in-service at year end 2013, PEF has used the rates contained in its May 2012 Earnings Surveillance Report (ESR) Weighted Average Cost of Capital. This rate is shown on page 42-8P, included in Exhibit TGF-3. Page 42-8P includes the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b). For PEF's investments in Project 7.4 (CAIR) expected to be in-service by year end 2013, PEF has continued to use the rate as included in Exhibit TGF-1 Form 42-9E. This is consistent with the language contained in Order No. PSC-12-0425-PAA-EU excluding PEF's CAIR investment expected to be in-service by year end 2013 from the application of the new methodology for calculating WACC to be applied to clauses.

Q. What effect does the Stipulation and Settlement Agreement Order No. PSC-12-0104-FOF-EI dated March 8, 2012 have on the (CAIR) Investments presented in this Docket (120007-EI)?

A. Due to the Settlement Agreement, PEF disaggregated the Project 7.4 CAIR assets that are expected to be in service by year end 2013 from those that will not yet be in-service. Specifically, paragraph 14 of the Settlement Agreement provides that effective with the first billing cycle of January 2014, PEF is authorized to remove the capital assets installed and in-service on the Crystal River Units 4 & 5 ("CR4 & 5") power plants to comply with the Federal Clean Air Interstate Rule ("CAIR") from the Environmental Cost Recovery Clause ("ECRC") and transfer those capital assets to base rates in an amount which will equal the annual retail revenue requirements of the assets projected to be in-service as of December 31, 2013 (excluding O&M related costs) which is reflected in the Company's filing (Form 42-4P; Project 7.4, Page 8 of 17) in Docket 120007-EI in Exhibit_(TGF-3). Because the Settlement Agreement only provides for the transfer of assets projected to be in-service by year end 2013 to base rates, PEF has broken out Project 7.4 Crystal River FGD and SCR into two pages (pages 8 and 9 of Form 42-4P). The investments that are not projected to be in-service at year end 2013 will continue to be recovered through ECRC in future Dockets.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2013?

A. Yes. Form 42-2P contained in Exhibit No. __ (TGF-3R) summarizes the recoverable jurisdictional O&M cost estimates for these projects in the amount of approximately $32.7 million.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2013?

A. Yes. Form 42-3P contained in Exhibit No. __ (TGF-3R) summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 17, shows the calculations of these costs that result in recoverable jurisdictional capital costs of approximately $162.6 million.

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

A. Yes. Form 42-5P, pages 1 through 20, contained in Exhibit No. __ (TGF-3R) provide each project description and progress, as well as projected recoverable cost estimates.

Q. What is the total projected jurisdictional costs for environmental compliance activities in the year 2013?

A. The total jurisdictional capital and O&M costs of approximately $195.4 million to be recovered through the ECRC, are calculated on Form 42-1P, Line 1c of Exhibit No. __ (TGF-3R).

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

A. The ECRC factors were calculated as shown on Forms 42-6P and 42-7P contained in Exhibit No. __(TGF-3R). The demand component of class allocation factors were calculated by determining the percentage each rate class contributes to the monthly system peaks and then adjusted for losses for each rate class. This information was obtained from PEF's load research study filed July 2012. The energy allocation factors were calculated by determining the percentage each rate class contributes to total kilowatt-hour sales and then adjusted for losses for each rate class. Form 42-7P presents the calculation of the proposed ECRC billing factors by rate class.

Q. Are there any non-CAIR assets projected to go into service in 2013? If, so how will the revenue requirements for those projects be allocated to the Rate Classes?

A. Yes. As further explained in Witness Hixon's testimony, the Anclote Gas Conversion (Project 17.1) is expected to be placed in-service in 2013. The recoverable costs will be calculated using the retail energy factor and allocated to rate classes on an energy basis.

Q. Are any adjustments included in Exhibit TGF-3 or TGF-4?

A. Yes. There were 2 small adjustments made to reflect corrections to information contained in Exhibits TGF-1 and TGF-2. These corrections are relatively minor and have the effect of making the revenue requirement included in Exhibit TGF-3 correct.

Q. Can you describe these adjustments?

A. Yes. First, after Exhibit TGF-1 was filed, it was discovered that there was an error in the estimated ammonia costs on schedule 42-8E page 10. The result was to overstate ammonia expense by approximately $350 thousand in 2012. I have corrected this by placing a credit in January of 2013 on Schedule 42-4P page 10 in line 6a. Second, there were two projects in Exhibit TGF-2 that should have had a different depreciation rate. These are projects 7.4e and 7.4k as included in the Capital Program Detail. To correct this, I have adjusted the beginning balance for accumulated depreciation for these two projects by approximately $67 thousand and $17 thousand, respectively. Additionally, I have adjusted form 42-3P of Exhibit TGF-3 line 1, project 7.4 CAIR/CAMR Crystal River AFUDC – Base to reduce the revenue requirements by approximately this amount. By incorporating these adjustments the revenue requirement in Exhibit TGF-3 line 5 is correct.

Q. What are PEF's proposed 2013 ECRC billing factors by the various rate classes and delivery voltages?

A. The computation of PEF's proposed ECRC factors for 2013 customer billings is shown on Form 42-7P, contained in Exhibit No. __(TGF-3R). In summary, these factors are as follows:

RATE CLASS	ECRC FACTORS 12CP & 1/13AD
Residential	0.494 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.490 cents/kWh
@ Primary Voltage	0.485 cents/kWh
@ Transmission Voltage	0.480 cents/kWh
General Service 100% Load Factor	0.484 cents/kWh
General Service Demand	
@ Secondary Voltage	0.485 cents/kWh
@ Primary Voltage	0.480 cents/kWh
@ Transmission Voltage	0.475 cents/kWh
Curtailable	
@ Secondary Voltage	0.485 cents/kWh
@ Primary Voltage	0.480 cents/kWh
@ Transmission Voltage	0.475 cents/kWh
Interruptible	
@ Secondary Voltage	0.474 cents/kWh
@ Primary Voltage	0.469 cents/kWh
@ Transmission Voltage	0.465 cents/kWh
Lighting	0.476 cents/kWh

Q. When is PEF requesting that the proposed ECRC billing factors be made effective?

A. PEF is requesting that its proposed ECRC billing factors be made effective with the first bill group for January 2013 and continues through the last bill group for December 2013.

Q. Please summarize your testimony.

A. My testimony supports the approval of an average environmental billing factor of 0.489 cents per kWh which includes projected capital and O&M revenue requirements of approximately $182.6 million associated with a total of 17 environmental projects and a true-up over-recovery provision of approximately $12.9 million. My testimony also demonstrates that the projected environmental expenditures for 2013 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

A. My name is Howard T. Bryant. 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 graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position, I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have testified before this Commission on ECRC activities since 2001 as well as conservation and load management activities, DSM goals setting, DSM plan approval dockets and other ECCR dockets since 1993.

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 ECRC and the calculations associated with the environmental compliance activities for the January 2011 through December 2011 period.

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

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

- Form 42-1A, Document No. 1, Final true-up for the January 2011 through December 2011 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, provides details to the calculation of the interest provision for the period;
- Form 42-4A, Document No. 4, reflects the calculation of 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 details of the calculation of variances between actual and actual/estimated costs for capital investment projects;
- Form 42-7A, Document No. 7, presents a summary of actual monthly costs for capital investment projects for the period;
- Form 42-8A, Document No. 8, pages 1 through 25, consist of the calculation of depreciation expenses and return on capital investment for each project that is being recovered through the ECRC, and page 26 calculates the net expenses associated with maintaining an SO_2 allowance inventory.

- Form 42-9A, Document No. 9, consisting of one page, details the calculation of Tampa Electric's capital structure, components and cost rates.

Q. What is the source of the data presented by way of your testimony or exhibits in this process?

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 actual true-up amount Tampa Electric is requesting for the January 2011 through December 2011 period?

A. Tampa Electric has calculated and is requesting approval of an under-recovery of $3,696,541 as the actual true-up amount for the January 2011 through December 2011 period.

Q. What is the adjusted net true-up amount Tampa Electric is requesting for the January 2011 through December 2011 period which is to be applied in the calculation of the environmental cost recovery factors to be refunded/(recovered) in the 2013 projection period?

A. Tampa Electric has calculated an under-recovery of $3,232,451 reflected on Form 42-1A, as the adjusted net true-up amount for the January 2011 through December 2011 period. This adjusted net true-up amount is the difference between the actual under-recovery and the actual/estimated under-recovery for the January 2011 through December 2011 period as depicted on Form 42-1A. The actual true-up amount for the January 2011 through December 2011 period is an under-recovery of $3,696,541 as compared to the $464,090 actual/estimated under-recovery amount approved in Commission Order No. PSC-11-0553-FOF-EI issued December 7, 2011.

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

Q. Did Tampa Electric include costs in its 2011 final ECRC true-up filing for any environmental projects that were not anticipated and included in its 2011 factors?

A. No.

Q. How did actual expenditures for the January 2011 through December 2011 period compare with Tampa Electric's actual/estimated projections as presented in previous testimony and exhibits?

A. As shown on Form 42-4A, total O&M activities costs were $1,504,331 or 7.2 percent more than the actual/estimated projections. Form 42-6A shows the total capital investment costs were $46,355 or 0.1 percent less than the actual/estimated projections. O&M projects with material variances from the 2011 Actual/Estimated True-Up filing are explained below. Variances for capital investment projects are quite modest; therefore, explanations are not provided.

O&M Project Variances

- **Big Bend Unit 3 Flue Gas Desulfurization Integration:** The Big Bend Unit 3 Flue Gas Desulfurization Integration project variance was $388,266 or 7.0 percent more than projected due to an increase in consumables used for operations as well as an increase in the prices for consumables.

- **SO_2 Emissions Allowances:** The SO_2 Emission Allowances project variance was $9,782 or 36.3 percent less than projected. The variance was due to less cogeneration purchases than originally projected.
- **Big Bend Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance was $524,523 or 6.9 percent more than projected due to increase in operations, which in turn, caused an increase in limestone consumption.
- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance was $162,147 or 58 percent more than projected due to preventative maintenance on system as well as facilitating best practices on fly ash system.
- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance was $51,128 or 13.5 percent less than projected due to maintenance activity being less than expected during planned outages.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance was 65,970 or 89.8 percent lower than projected due to a postponement of the study that was scheduled to occur in 2011 regarding cooling towers at the plant.

- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance was $32,619 or 31.9 percent greater than projected due to scheduled outages being cancelled, in turn causing more ammonia being consumed than originally anticipated.
- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study was $18,623 or 34.3 percent greater than projected due to EPA's extension of the comment period and postponing of final rule. The extension created the need for additional outside services in preparation for EPA's rendering of the final rule.
- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance was $150,508 or 7.6 percent greater than projected due to the increase in ammonia consumption driven by the increase in generating unit production as well as usage for SO_3 mitigation system.
- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance was $221,267 or 17.3 percent greater than projected due to the increase in ammonia consumption driven by the increase in generating unit production as well as usage for SO_3 mitigation system.
- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance was $93,985 or 6.5 percent greater than projected due to the increase in ammonia consumption

driven by the increase in generating unit production as well as usage for SO_3 mitigation system.

- **Greenhouse Gas Reduction Program:** The Greenhouse Gas Reduction Program variance was $49,583 or 115.4 percent greater than originally projected due to a software subscription that was due for renewal in 2011.

Q. Did Tampa Electric make any adjustments to the 2011 true-up period?

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120007-EI
FILED: 08/01/12

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

A. My name is Howard T. Bryant. 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 graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goals setting and DSM plan approval dockets, and other ECCR dockets since 1993, and ECRC activities since 2001.

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

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2012 through December 2012 estimated true-up amount to be refunded or recovered through the ECRC during January 2013 through December 2013. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2012, based on six months of actual data and six months of estimated data. This information will be used to determine the environmental cost recovery factors for January 2013 through December 2013.

Q. Have you prepared an exhibit that shows the determination of the recoverable environmental costs for the period January 2012 through December 2012?

A. Yes. Exhibit No. _____ (HTB-2), containing nine documents, was prepared under my direction and supervision. It includes Forms 42-1E through 42-9E which show the current period estimated true-up amount to be used in calculating the cost recovery factors for January 2013 through December 2013.

Q. What has Tampa Electric calculated as the estimated true-up for the current period to be applied to the January 2013 through December 2013 ECRC factors?

A. The estimated true-up applicable for the current period, January 2012 through December 2012, is an under-recovery of $11,754,826. A detailed calculation supporting the estimated true-up is shown on Forms 42-1E through 42-8E of my exhibit.

Q. Is Tampa Electric including costs in this estimated true-up filing for any new environmental projects that were not anticipated and included in its 2012 factors?

A. No, Tampa Electric is not including costs for any new environmental projects that were not anticipated or included in its 2012 factors.

Q. What depreciation rates were utilized for the capital projects contained in the 2012 Actual/Estimated True-Up?

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

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2012 through December 2012?

A. Tampa Electric relied upon the capital structure approved by the Commission in Docket No. 080317-EI, to calculate the revenue requirement rate of return found on Form 42-9E.

Q. How did the actual/estimated project expenditures for January 2012 through December 2012 period compare with the company's original projection?

A. As shown on Form 42-4E, total O&M activities were $8,145,980 greater than projected costs. Total capital expenditures itemized on Form 42-6E, were $3,114,886 greater than originally projected. O&M and capital investment projects with material variances are explained below.

O&M Project Variances

- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is estimated to be $12,303 or 55.3 percent less than projected. The variance was due to less cogeneration purchases than expected and the application of a lower rate than originally projected.
- **Big Bend Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance is estimated to be $8,771,061 or 99.3 percent greater than projected due to landfilling approximately 350,000 tons of lesser quality gypsum to be used as valley fill in two landfills.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance is estimated to be $20,000 or 100 percent less than originally projected. This variance is due to pending acceptance of Big Bend Plan of Study regarding thermal variances that will have regulatory impact at Bayside Power Station.
- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions

Reduction project variance is estimated to be $18,664 or 53.3 percent lower than originally projected due to forced outages at the Polk Power Station in addition to a reduction in water costs and maintenance associated with the saturator that is used to reduce NO_x emissions.

- **Clean Water Act Section 316(b)Phase II Study:** The Clean Water Act Section 316(b) Phase II Study project variance is estimated to be $26,140 or 87.1 percent greater than originally projected due to EPA's extension of the comment period and postponing of the final rule. The extension created the need for additional outside services in preparation for EPA's rendering of the final rule.
- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program variance is estimated to be $582,501 or 87.3 percent less than what was originally projected due to FDEP delay in approval of activity associated with project work.
- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is estimated to be $166,118 or 6.7 percent less than originally projected due to a decrease in generation caused by extended outages, thereby creating a lower consumption of ammonia than originally projected.

- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is estimated to be $208,157 or 8.2 percent less due to actual consumption of ammonia for the SO_3 mitigation system being less than originally projected. The ammonia is utilized in the SO_3 mitigation system to meet ongoing environmental regulation requirements.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is estimated to be $355,889 or 23.5 percent greater than originally projected due to actual consumption of ammonia for the SO_3 mitigation system being greater than originally projected. The ammonia is utilized in the SO_3 mitigation system to meet ongoing environmental regulation requirements.
- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is estimated to be $130,201 or 13 percent less than originally projected due to a credit for equipment that offset an increase in ammonia consumption for the SO_3 mitigation system.
- **Greenhouse Gas Reduction Program:** The Greenhouse Gas Reduction Program variance is expected to be $50,788 or 127 percent greater than originally projected due to the cost of the Enviance subscription being higher than originally projected.

<u>**Capital Investment Project Variances**</u>

- **Big Bend Unit 1 & 2 Flue Gas Conditioning:** The Big Bend

Units 1 & 2 Flue Gas Conditioning project variance is estimated to be $30,874 or 8.0 percent greater than originally projected due to updating depreciation rates consistent with the current depreciation study approved by the Commission in Order No. PSC-12-0175-PAA-EI.

- **Big Bend Unit 4 Continuous Emissions Monitors:** The Big Bend Unit 4 Continuous Emissions Monitors project variance is estimated to be $8,976 or 12.1 percent greater than originally projected due to updating depreciation rates consistent with the current depreciation study approved by the Commission in Order No. PSC-12-0175-PAA-EI.
- **Phillips Upgrade Tank #1 for FDEP:** The Phillips Upgrade Tank #1 for FDEP project variance is estimated to be $26,051 or 494.6 percent greater than originally projected due to the retirement of this asset and the resulting recovery of net investment.
- **Phillips Upgrade Tank #4 for FDEP:** The Phillips Upgrade Tank #4 for FDEP project variance is estimated to be $40,782 or 493.3 percent greater than originally projected due to the retirement of this asset and the resulting recovery of net investment.
- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is estimated to be $24,275 or 6.9 percent greater than originally projected due to updating

depreciation rates consistent with the current depreciation study approved by the Commission in Order No. PSC-12-0175-PAA-EI.

- **Big Bend Unit 1 SCR**: The Big Bend Unit 1 SCR project variance is estimated to be $1,069,552 or 9.3 percent greater than originally projected due to updating depreciation rates consistent with the current depreciation study approved by the Commission in Order No. PSC-12-0175-PAA-EI.
- **Big Bend Unit 2 SCR**: The Big Bend Unit 2 SCR project variance is estimated to be $849,988 or 6.8 percent greater than originally projected due to updating depreciation rates consistent with the current depreciation study approved by the Commission in Order No. PSC-12-0175-PAA-EI.
- **Big Bend Unit 3 SCR**: The Big Bend Unit 3 SCR project variance is estimated to be $846,891 or 8.3 percent greater than originally projected due to updating depreciation rates consistent with the current depreciation study approved by the Commission in Order No. PSC-12-0175-PAA-EI.
- **Big Bend Unit 4 SCR**: The Big Bend Unit 4 Pre-SCR project variance is estimated to be $564,010 or 7.2 percent greater than projected due to updating depreciation rates consistent with the current depreciation study approved

by the Commission in Order No. PSC-12-0175-PAA-EI.

- **Big Bend Units FGD System Reliability**: The Big Bend FGD System Reliability program variance is estimated to be $496,190 or 14.3 percent less than originally projected due to the overall expenditures for the project now estimated to be less. Additionally, the anticipated in-service date has been extended to July 2012 from its original anticipated date of January 2012.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120007-EI
FILED: AUGUST 30, 2012

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

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

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

A. I graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goals setting and DSM plan approval dockets, and other ECCR dockets since 1993, and ECRC activities since 2001.

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

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the revenue requirements and the projected ECRC factors for the period of January 2013 through December 2013. In support of the projected ECRC factors, my testimony identifies the capital and operating and maintenance ("O&M") costs associated with environmental compliance activities for the year 2013.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2013 through December 2013?

A. Yes. Exhibit No. ___ (HTB-3), containing eight documents, was prepared under my direction and supervision. Document Nos. 1 through 8 contain Forms 42-1P through 42-8P, which show the calculation and summary of O&M and capital expenditures that support the development of the environmental cost recovery factors for 2013.

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

A. Yes. The ECRC factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (HTB-3), Document No. 7, on Form 42-7P. These annualized factors will apply for the period January through December 2013.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2013 through December 2013?

A. The net true-up applicable for this period is an under-recovery of $14,987,277. This consists of the final true-up under-recovery of $3,232,451 for the period of January 2011 through December 2011 and an estimated true-up under-recovery of $11,754,826 for the current period of January 2012 through December 2012. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-9E of Exhibit No. ___ (HTB-2) filed with the Commission on August 1, 2012.

Q. What were the major contributing factors that created the net under-recovery to be applied to the company's ECRC rates for the period January 2013 through December 2013?

A. There were two major contributing factors that created the net under-recovery. First, the increased O&M expense associated with the management of the gypsum production at Big Bend Station. Second, capital costs increased due to the use of newly approved depreciation rates for several projects.

Q. Will Tampa Electric include any new environmental compliance projects for ECRC cost recovery for the period from January 2013 through December 2013?

A. No, Tampa Electric is not including any new environmental compliance projects for ECRC cost recovery during 2013.

Q. What are the existing capital projects included in the calculation of the ECRC factors for 2013?

A. Tampa Electric proposes to include for ECRC recovery the 24 previously approved capital projects and their projected costs in the calculation of the ECRC factors for 2013. These projects are:

1) Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) Big Bend Unit 4 Continuous Emissions Monitors
4) Big Bend Fuel Oil Tank 1 Upgrade
5) Big Bend Fuel Oil Tank 2 Upgrade
6) Big Bend Unit 1 Classifier Replacement
7) Big Bend Unit 2 Classifier Replacement
8) Big Bend Section 114 Mercury Testing Platform
9) Big Bend Units 1 and 2 FGD
10) Big Bend FGD Optimization and Utilization
11) Big Bend NO_x Emissions Reduction
12) Big Bend Particulate Matter ("PM") Minimization and Monitoring
13) Polk NO_x Emissions Reduction
14) Big Bend Unit 4 SOFA
15) Big Bend Unit 1 Pre-SCR
16) Big Bend Unit 2 Pre-SCR

17) Big Bend Unit 3 Pre-SCR
18) Big Bend Unit 1 SCR
19) Big Bend Unit 2 SCR
20) Big Bend Unit 3 SCR
21) Big Bend Unit 4 SCR
22) Big Bend FGD Reliability
23) Clean Air Mercury Rule
24) SO_2 Emission Allowances

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

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2013?

A. Yes. Form 42-3P contained in Exhibit No. ___ (HTB-3) summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 26, provides the calculations of the costs, which result in recoverable jurisdictional capital costs of $60,257,233.

Q. What are the existing O&M projects included in the calculation of the ECRC factors for 2013?

A. Tampa Electric proposes to include for ECRC recovery the 22 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2013. These projects are:

1) Big Bend Unit 3 FGD Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) SO_2 Emissions Allowances
4) Big Bend Units 1 and 2 FGD
5) Big Bend PM Minimization and Monitoring
6) Big Bend NO_x Emissions Reduction
7) NPDES Annual Surveillance Fees
8) Gannon Thermal Discharge Study
9) Polk NO_x Emissions Reduction
10) Bayside SCR and Ammonia
11) Big Bend Unit 4 SOFA
12) Big Bend Unit 1 Pre-SCR
13) Big Bend Unit 2 Pre-SCR
14) Big Bend Unit 3 Pre-SCR
15) Clean Water Act Section 316(b) Phase II Study
16) Arsenic Groundwater Standard Program
17) Big Bend Unit 1 SCR
18) Big Bend Unit 2 SCR
19) Big Bend Unit 3 SCR
20) Big Bend Unit 4 SCR

21) Clean Air Mercury Rule
22) Greenhouse Gas Reduction Program

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

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2013?

A. Yes. Form 42-2P contained in Exhibit No. ___ (HTB-3) summarizes the recoverable jurisdictional O&M costs for these projects which total $25,768,511 for 2013.

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

A. Yes. Project descriptions and progress reports, as well as the projected recoverable cost estimates, are provided in Form 42-5P, pages 1 through 32.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2013?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $86,025,744.

Q. How were environmental cost recovery factors calculated?

A. The environmental cost recovery factors were calculated as shown on Schedules 42-6P and 42-7P. The demand allocation factors were calculated by determining the percentage each rate class contributes to the monthly system peaks and then adjusted for losses for each rate class. The energy allocation factors were determined by calculating the percentage that each rate class contributes to total MWH sales and then adjusted for losses for each rate class. This information was based on applying historical rate class load research to the 2013 projected forecast of system demand and energy. Form 42-7P presents the calculation of the proposed ECRC factors by rate class.

Q. What are the ECRC billing factors by rate class for the period of January through December 2013 which Tampa Electric is seeking approval?

A. The computation of the billing factors by metering voltage level is shown in Exhibit No. ___ (HTB-3) Document No. 7, Form 42-7P. In summary, the January through December 2013 proposed ECRC billing factors are as follows:

Rate Class		**Factor by Voltage Level (¢/kWh)**
RS Secondary		0.558
GS, TS Secondary		0.557
GSD, SBF		
	Secondary	0.555
	Primary	0.550
	Transmission	0.544
IS		
	Secondary	0.545
	Primary	0.540
	Transmission	0.534
LS1		0.553
Average Factor		0.556

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 2013.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2013 through December 2013?

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

Q. Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2013 through December 2013 consistent with criteria established for ECRC recovery in Order No. PSC-94-0044-FOF-EI?

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

1. Such costs were prudently incurred after April 13, 1993;
2. The activities are legally required to comply with a governmentally imposed environmental regulation enacted, became effective or whose effect was triggered after the company's last test year upon which rates are based; and,

3. Such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. Please summarize your testimony.

A. My testimony supports the approval of a final average environmental billing factor credit of 0.556 cents per kWh. This includes the projected capital and O&M revenue requirements of $86,025,744 associated with a total of 30 environmental projects and a true-up under-recovery provision of $14,987,277 that is primarily driven by the combination of O&M and capital expenditures being greater than anticipated while ECRC revenue was less than expected. My testimony also explains that the projected environmental expenditures for 2013 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PAUL CARPINONE

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

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

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

A. I received a Bachelor of Science degree in Water Resources Engineering Technology from the Pennsylvania State University in 1978. I have been a Registered Professional Engineer in the State 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, Environmental Health and Safety. My responsibilities include the development and administration of the company's environmental, health and safety policies and goals. I am also responsible for ensuring resources, procedures and programs meet or surpass compliance with applicable environmental, health and safety requirements, and that rules and policies are in place and functioning appropriately and consistently throughout the company.

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

A. The purpose of my testimony is to demonstrate that the activities for which Tampa Electric seeks cost recovery through the Environmental Cost Recovery Clause ("ECRC") for the January 2013 through December 2013 projection period are activities necessary for the company to comply with various environmental requirements. Specifically, I will describe the ongoing activities that are associated with the Consent Final Judgment ("CFJ") entered into with the Florida Department of Environmental Protection ("FDEP") and the Consent Decree ("CD") lodged with the U.S. Environmental Protection Agency ("EPA") and the Department of Justice. I will also discuss other programs previously approved by the Commission for recovery through the ECRC.

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

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

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

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

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

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

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

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

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

Q. Please describe the Big Bend PM Minimization and Monitoring program activities and provide the estimated capital and O&M expenditures for the period of January 2013 through December 2013.

A. The Big Bend PM Minimization and Monitoring program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. In the Order, the Commission found that the program met the requirements for recovery through the ECRC. Tampa Electric had previously identified various projects to improve precipitator performance and reduce PM emissions as required by the Orders. In 2013, capital expenditures are anticipated to be $7,902,900 for BOP and BACT equipment while O&M expenses associated with existing and recently installed BOP and BACT equipment and continued implementation of the BOP procedures are expected to be $390,000.

Q. What do the Orders require for NO_x reductions?

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

Q. Please describe the Big Bend NO_x Emission Reduction program activities and provide the estimated capital and O&M expenses for the period of January 2013 through December 2013.

A. The Big Bend NO_x Emission Reduction program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. In the Order, the Commission found that the program met the requirements for recovery through the ECRC. No capital expenditures are anticipated in 2013; however, Tampa Electric will perform maintenance on the previously approved and installed NO_x Reduction equipment. This activity is expected to result in approximately $375,000 of O&M

expenses.

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

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

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

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

Q. Please describe the Big Bend Units 1 through 3 Pre-SCR and the Big Bend Units 1 through 4 SCR projects and provide estimated capital and O&M expenditures for the period of January 2013 through December 2013.

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

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

For the period of January 2013 through December 2013, no capital or O&M expenditures are anticipated for the Big Bend Units 1 through 3 Pre-SCR projects. For 2013, there are no anticipated capital expenditures for Big Bend Units 2, 3 and 4 SCRs; however, the anticipated capital expenditure for Big Bend Unit 1 SCR is $2,000,000 for catalyst replacement. The 2013 SCR O&M expenses are projected to be $2,259,818 for Big Bend Unit 1 SCR, $2,506,409 for Big Bend Unit 2 SCR, $1,548,628 for Big Bend Unit 3 SCR and $1,041,076 for Big Bend Unit 4 SCR. O&M expenses are driven by ammonia purchases.

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

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

1) Big Bend Unit 3 FGD Integration
2) Big Bend Units 1 and 2 FGD
3) Gannon Thermal Discharge Study
4) Bayside SCR Consumables

5) Clean Water Act Section 316(b) Phase II Study
6) Big Bend FGD System Reliability
7) Arsenic Groundwater Standard
8) Clean Air Mercury Rule ("CAMR")
9) Greenhouse Gas ("GHG") Reduction 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 2013 through December 2013.

A. The Big Bend Unit 3 FGD Integration program was approved by the Commission in Docket No. 960688-EI, Order No. PSC-96-1048-FOF-EI, issued August 14, 1996. The Big Bend Units 1 and 2 FGD program was approved by the Commission in Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999. In those Orders, the Commission found that the programs met the requirements for recovery through the ECRC. The programs were implemented to meet the SO_2 emission requirements of the Phase I and II Clean Air Act Amendments ("CAAA") of 1990.

The projected January 2013 through December 2013 capital expenditures for the Big Bend Unit 3 FGD Integration project are $3,507,284 for controls upgrades as well as duct replacements. O&M expenses are anticipated to be $5,526,100 for consumables and ongoing maintenance. The projected January 2013 through December 2013 capital expenditures for the Big Bend FGD Units 1 and 2 project are $1,195,443 for improvements to waste water treatment reliability and the oxidation air header, both scheduled to occur during the spring outage. O&M expenses are anticipated to be $11,080,000 for consumables and ongoing maintenance.

Q. Please describe the Gannon Thermal Discharge Study program activities and provide the estimated capital and O&M expenditures for the period of January 2013 through December 2013.

A. The Gannon Thermal Discharge Study program was approved by the Commission in Docket No. 010593-EI, Order No. PSC-01-1847-PAA-EI, issued September 14, 2001. In that Order, the Commission found that the program met the requirements for recovery through the ECRC. For the period of January 2013 through December 2013, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses will be approximately $12,500 for continuation of the ongoing study.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated capital and O&M expenditures for the period of January 2013 through December 2013.

A. The Bayside SCR Consumables program was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. For the period of January 2013 through December 2013, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses associated with the consumable goods (primarily anhydrous ammonia) will be approximately $106,000 for the period.

Q. Please describe the Clean Water Act Section 316(b) Phase II Study program activities and provide the estimated capital and O&M expenditures for the period of January 2013 through December 2013.

A. The Clean Water Act Section 316(b) Phase II Study program was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005. On March 20, 2007 the EPA announced that the rule adopted pursuant to Section 316(b) be considered suspended. The suspension of the final rule was made on July 9, 2007. On

April 20, 2012, EPA published a proposed rule for existing steam electric generators, with the final rule expected in July 2012. In July 2012, the final rule was postponed once again until June 2013. Tampa Electric believes that the current work will continue to be useful for purposes related to the Phase II Rule and does not intend to suspend the work because it would not be cost-effective or appropriate to do so. Therefore, Tampa Electric anticipates O&M expenses associated with the 2013 planned study activities will be approximately $60,000. No capital expenditures are anticipated.

Q. Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital and O&M expenses for the period of January 2013 through December 2013.

A. Tampa Electric's Big Bend FGD System Reliability program was approved by the Commission in Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006. The Commission granted cost recovery approval for prudent costs associated with this project. The Big Bend FGD System Reliability project has been running concurrently with the installation of SCR systems on the generating units.

For the period of January 2013 through December 2013, there are no anticipated capital or O&M expenditures for this project.

Q. Please describe the Arsenic Groundwater Standard program activities and provide the estimated capital and O&M expenditures for the period of January 2013 through December 2013.

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

For the period of January 2013 through December 2013, there will be no capital expenditures for this program; however, Tampa Electric anticipates O&M expenses associated with the sampling activities will be approximately $667,000.

Q. Please describe the CAMR program activities and provide the estimated capital and O&M expenditures for the period of January 2013 through December 2013.

A. The CAMR program was approved by the Commission in Docket No. 060583-EI, Order No. PSC-06-0926-PAA-EI, issued November 6, 2006. In that Order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric cost recovery approval for prudently incurred costs.

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

For 2013, there are no capital expenditures anticipated; however, O&M expenditures are projected to be $20,000.

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

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

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

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

Q. Please describe the GHG Reduction Program activities and provide the estimated capital and O&M expenditures for the period of January 2013 through December 2013.

A. Tampa Electric's GHG Reduction Program approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PPA-EI, issued March 22, 2010 is a result of the EPA's Mandatory Reporting Rule requiring annual reporting of greenhouse gas emissions. Tampa Electric is required to report greenhouse gas emissions to the EPA for the first time in 2011. Reporting for the EPA's Greenhouse Gas Mandatory Reporting Rule will continue in 2013. For 2013, this activity is not anticipated to require capital expenditures; however, it is expected to result in approximately $90,000 in O&M expenses.

Q. Please summarize your testimony.

A. Tampa Electric's settlement agreements with FDEP and EPA require significant reductions in emissions from Tampa Electric's Big Bend and Gannon Stations. The Orders established definite requirements and time frames in which air quality improvements must be made and result in reasonable and fair outcomes for Tampa Electric, its community and customers, and the environmental agencies. My testimony identified projects that are legally required by these Orders. I described the progress Tampa Electric has made to achieve the more stringent environmental standards. I have identified estimated costs, by project, which the company expects to incur in 2013. Additionally, my testimony identified other projects that are required for Tampa Electric to meet the environmental requirements and I provided the associated 2013 activities and projected expenditures.

Q. Does this conclude your testimony?

A. Yes it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 120007-EI
April 2, 2012

Q. Please state your name and business address.

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

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

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

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

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

Q. What are your responsibilities with Gulf Power Company?

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

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

A. Yes.

Q. Mr. Vick, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's Environmental Cost Recovery Clause (ECRC) final true-up for the period January through December 2011.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2011 through December 2011 with the approved estimated true-up amounts.

A. As reflected in Mr. Dodd's Schedule 6A, the actual recoverable capital costs were $127,290,583 as compared to $127,285,793 included in the Estimated True-up filing. This resulted in a net variance of $4,790 above the estimated true-up. I will address three projects and/or programs that contributed to this variance: Crist 5, 6, & 7 Precipitator Projects, Smith Water Conservation, and CAIR/CAMR/CAVR Compliance.

Q Please explain the capital variance of ($68,108) or (3.2%) in the Crist 5, 6, & 7 Precipitator Projects (Line Item 1.2).

A. Due to a delay in material and equipment deliveries for the Plant Crist Unit 6 precipitator project, some construction activities were delayed until 2012. These delays resulted in lower carrying costs than originally projected.

Q. Please explain the capital variance of ($75,000) or (82.1%) in the Smith Water Conservation Program (Line Item 1.17).

A. As stated in previous fillings, Gulf is determining whether the existing site properties make it feasible for injection of used reclaimed water. Gulf will also make decisions on the completion of additional injection wells and the associated monitoring wells that would be required by the Florida Department of Environmental Protection (FDEP) Underground Injection Control Group. Gulf is currently in the drilling and testing phase of the test well for the Smith Water Conservation Program. As a result of the testing and evaluation process not being complete and a final agreement having not been reached with the applicable suppliers of reclaimed water, the decision to move forward with the project has not yet been made. This has resulted in lower carrying costs for this project than projected.

Q Please explain the capital variance of $164,991 or 0.2% in the CAIR/CAMR/CAVR Compliance Program (Line Item 1.26).

A. This variance is due to higher carrying costs than originally projected because of changes in the timing of portions of the Plant Crist Unit 6 SCR project being placed into service. In the 2011 Estimated True-up filing, Gulf failed to reflect expenditures for safety & fire protection equipment, compressed air piping and other miscellaneous items related to portions of the SCR project being placed in service in 2011.

Q. How do the actual O&M expenses for the period January 2011 to December 2011compare to the amounts included in the Estimated True-up filing?

A. Mr. Dodd's Schedule 4A reflects that Gulf's recoverable environmental O&M expenses for the current period were $23,895,071, as compared to the estimated true-up of $25,391,528. This resulted in a variance of ($1,496,457) or (5.9%) below the estimated true-up. I will address eight O&M projects and/or programs that contribute to this variance: Air Emission Fees, Title V, General Solid & Hazardous Waste, FDEP NOx Reduction Agreement, CAIR/CAMR/CAVR Compliance, Crist Water Conservation, Annual NOx Allowances, and SO_2 Allowances.

Q. Please explain the variance of ($124,374) or (16.2%) in (Line item 1.2) Air Emission Fees and the variance of $113,627 or 96.1% in (Line item 1.3) Title V program.

A. These variances are due to Air Emissions fees of $124,374 charged to the Title V program instead of the Air Emission Fees program. As a result, the net variance of the Air Emission Fees and the Title V programs is ($10,747).

Q. Please explain the variance of $128,147 or 16.7% 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 several large transformer oil spills and disposal costs for Gulf's power delivery operations that were not projected.

Q Please explain the variance of ($54,836) or (2.8%) in FDEP NOx Reduction Agreement (Line Item 1.19).

A. The FDEP NOx Reduction Agreement includes O&M costs associated with the Plant Crist Unit 7 SCR and the Crist Units 4 through 6 SNCR projects that were included as part of the 2002 agreement with FDEP. More specifically, this line item includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the agreement. This variance is primarily due to less ammonia and urea being needed due to burning less coal at Plant Crist than originally projected.

Q. Please explain the O&M variance ($740,227) or (5.3%) in the CAIR/CAMR/CAVR Compliance Program, (Line Item 1.20).

A. During 2011, the CAIR/CAMR/CAVR Compliance Program included O&M expenses associated with the Crist Units 4 through 7 scrubber, the Smith Units 1 and 2 SNCRs, and the Scholz mercury monitoring project. More specifically, this line item includes the cost of urea, limestone, and general operation and maintenance activities included in Gulf's CAIR/CAMR/CAVR Compliance Program. This variance is primarily due to the cost and scope of the scrubber maintenance activities such as booster fans, gas cooling duct expansion joints repairs and other maintenance repairs being less than originally projected.

Q. Please explain the O&M variance of $(138,610) or (95.6%) in the Crist Water Conservation Program (Line Item 1.22).

A. The Crist Water Conservation line item includes general O&M expenses associated with the new Plant Crist reclaimed water system. This variance is primarily due to the delay of exterior surface maintenance work for the three million gallon water tank that was originally scheduled to be completed in 2011.

Q. Please explain the variance of ($406,974) or (12.5%) in Annual NOx Allowances (Line Item 1.24) and the variance of ($259,513) or (20.9%) in SO_2 Allowances (Line Item 1.26).

A. Gulf burned less coal than projected for the period and thus had to surrender fewer allowances. The lower coal burns, primarily at Plants Smith and Daniel, were due to a combination of lower loads due to milder weather conditions and a change in the generation mix from coal to gas fired generation due to lower market prices for natural gas.

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

A. Yes.

GULF POWER COMPANY
Before the Florida Public Service Commission
Prepared Direct Testimony
James O. Vick
Docket No. 120007-EI
August 1, 2012

Q. Please state your name and business address.

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

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

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

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

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

Q. What are your responsibilities with Gulf Power Company?

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

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

A. Yes.

Q. Mr. Vick, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's Environmental Cost Recovery Clause (ECRC) estimated true-up for the period January through December 2012. This true-up is based on six months of actual data and six months of estimated data.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the estimated true-up calculation for the period January 2012 through December 2012 with the approved projected amounts.

A. As reflected in Mr. Dodd's Schedule 6E, the recoverable capital costs approved in the original projection total $144,604,181 as compared to the estimated true-up amount of $127,553,064. This resulted in a variance of ($17,051,117) or (11.8%). There are three capital projects and programs that contribute to this variance that I will discuss: The Crist 5, 6 & 7 Precipitator Projects, Daniel Ash Management Project, and the Smith Water Conservation Project.

Q. Are there any factors that have had an effect on all capital projects?

A. Yes. Gulf's cost of capital approved in its recent base rate case, Docket No. 110138-EI, is lower than its previously approved cost of capital which has resulted in the estimated/actual carrying cost amounts being lower than the original 2012 projections. Mr. Dodd will discuss this issue in more detail in his testimony, and thus the impact of the change in cost of capital is not addressed in my explanations below.

Q. Please explain the capital variance of ($1,656,462) or (26.3%) in the Crist 5, 6, & 7 Precipitator Projects (Line Item 1.2).

A. Approximately ($970,000) of this variance is due to lower carrying costs than originally projected because expenditures are expected to be less than originally anticipated. When preparing the 2012 ECRC projection filing last August, the Crist precipitator project scope of work and bids had not been completed. When the bids came in, they were lower than expected. Therefore, the total expenditures for the project were lower than originally projected resulting in lower carrying costs for 2012.

Q. Please explain the capital variance of ($243,960) or (12.1%) in the Daniel Ash Management Project (Line Item 1.16).

A. Approximately ($90,000) of this variance is attributed to retirement of a Plant Daniel ash storage cell that was not reflected in the 2012 Projection filing. As a result, depreciation expenses and property taxes associated with this program are lower than originally projected.

Q. Please explain the capital variance of ($770,045) or (98.2%) in the Smith Water Conservation Program (Line Item 1.17).

A. As stated in previous fillings, Gulf is determining whether the existing Plant Smith site properties make it feasible for injection of used reclaimed water. Both the test injection well and monitoring well required by the Florida Department of Environmental Protection (FDEP) have been installed. Gulf is currently in the testing phase of the project. Since the testing and evaluation process is not complete and a final agreement has not been reached with the applicable suppliers of reclaimed water, the decision to move forward with the project has not yet been made. This has resulted in lower carrying costs for this project in 2012 than projected.

Q. How do the estimated/actual 2012 O&M expenses compare to the original 2012 projections?

A. Mr. Dodd's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated at $23,824,688 as compared to $26,077,178. This results in an estimated year-end variance of ($2,252,490) or (8.6%). I will address eight O&M projects and programs that contribute to this variance: Air Emission Fees, Groundwater Contamination Investigation, General Solid & Hazardous Waste, FDEP NOx Reduction Agreement, CAIR/CAMR/CAVR Compliance Program, Annual NOx Allowances, Seasonal NOx Allowances and SO2 Allowances.

Q. Please explain the O&M variance of ($122,210) or (14.8 %) in (Line Item 1.2) Air Emission Fees.

A. The Air Emission Fees represent the expenses projected for the annual fees required by the Clean Air Act Amendments (CAAA) of 1990 that are payable to the FDEP and Mississippi Department of Environmental Quality. These fees are based on annual tons of emissions regulated under the Title V Air Program. Gulf's 2012 Air Emissions Fees were less than expected due to less coal being burned than originally projected.

Q. Please explain the O&M variance of $91,622 or 4.4% in (Line item 1.7) Groundwater Contamination Investigation Program.

A. This variance is due to costs associated with additional excavation projects for the removal and disposal of contaminated soils from substation sites. Two of these sites are undergoing construction to expand their capacity. Both of these construction projects have encountered complicated site conditions which increased the cost of contaminated soil removal and required special remediation techniques to be employed.

Q. Please explain the O&M variance of $203,814 or 44.5 % in (Line item 1.11) General Solid and Hazardous Waste Program.

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 disposal costs for Gulf's power delivery operations that were not projected.

Q. Please explain the O&M variance of $366,210 or 21.9% in FDEP NOx Reduction Agreement (Line Item 1.19).

A. The FDEP NOx Reduction Agreement includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the Plant Crist FDEP Agreement related to Ozone Attainment. This variance is primarily due to an increase in expenses for the Crist Unit 7 SCR and a decrease in expenses for the Crist SNCRs. The ammonia cost per ton for the Unit 7 SCR increased and additional maintenance work is scheduled for the Unit 7 SCR. These increases are projected to be partially offset by a decrease in urea cost for the SNCRs. The net result is an increase in this program of $366,210.

Q. Please explain the O&M variance ($1,446,213) or (8.8%) in the CAIR/CAMR/CAVR Compliance Program, (Line Item 1.20).

A. The CAIR/CAMR/CAVR Compliance Program currently includes O&M expenses associated with the Crist Units 4 through 7 scrubber and the Smith Units 1 and 2 SNCRs. More specifically, this line item includes the cost of urea, limestone, and general operation and maintenance activities included in Gulf's CAIR/CAMR/CAVR Compliance Program. The line item variance is primarily due to Gulf being able to sell more gypsum from Plant Crist which resulted in increased revenue and reduced gypsum handling expenses. Also, Plant Smith SNCR chemical expenses were less than originally projected due to burning less coal than originally anticipated.

Q. Please explain the O&M variance of $618,341 in Annual NOx Allowances (Line Item 1.24).

A. The Annual NOx program was not impacted by EPA's planned implementation of the Cross-State Air Pollution Control (CSPAR) rule beginning January 1, 2012 as originally projected. On December 30, 2011, less than 48 hours before compliance was set to begin, the D.C. Circuit Court issued a stay of CSAPR and ordered EPA to continue administering CAIR while CSAPR is stayed. As a result, for 2012 Gulf now projects to incur $722,012 of NOx emission allowance expense as compared to the $103,671 originally projected.

Q. Please explain the O&M variance of ($1,719,005) or (100.0%) in Seasonal NOx Allowances (Line Item 1.25).

A. Gulf's original 2012 projection of seasonal ozone emission allowance expense was based upon EPA's planned implementation of the Cross-State Air Pollution Control (CSPAR) rule beginning January 1, 2012. Under the CAIR Seasonal Ozone program, Gulf received more seasonal ozone emission allowance allocations than originally projected under CSPAR and, therefore, no longer anticipates a need to purchase additional emission allowances during 2012. As a result, Gulf's estimated true-up for 2012 seasonal ozone is a reduction of $1,719,005.

Q. Please explain the O&M variance of ($166,021) or (23.2%) in SO2 Allowances (Line Item 1.26).

A. This variance is the result of Gulf surrendering fewer SO2 allowances than originally projected due to a lower than projected coal burn. Gulf's generation mix in 2012 has been more heavily weighted toward natural gas-fired generation than projected due to its current lower economic dispatch cost. Natural gas fired generation has significantly lower SO2 emission rates than coal- fired generation

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

A. Yes.

GULF POWER COMPANY
Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 120007-EI
August 28, 2012

Q. Please state your name and business address.

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

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

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

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

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

Q. What are your responsibilities with Gulf Power Company?

A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs section to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e., both existing laws and such laws and regulations that may be enacted or amended in the future. In performing this function, I have the responsibility for numerous environmental activities.

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

A. Yes.

Q. Mr. Vick, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's projection of environmental compliance costs recoverable through the Environmental Cost Recovery Clause (ECRC) for the period from January 2013 through December 2013.

Q. Mr. Vick, please identify the capital projects included in Gulf's ECRC projection filing.

A. The environmental capital projects for which Gulf seeks recovery through the ECRC are described in Schedules 3P, 4P, and 5P. I am supporting the expenditures, clearings, retirements, salvage and cost of removal currently projected for each of these projects. Mr. Dodd compiled these schedules and has calculated the associated revenue requirements for

Gulf's requested recovery. Of the projects shown on Mr. Dodd's schedules, there are three projects that were previously approved by the Commission with activities that have projected capital expenditures during 2013. These projects include: Substation Contamination Remediation, Smith Water Conservation, and the CAIR/CAMR/CAVR Compliance program.

Q. Mr. Vick, please describe the project included in the 2013 projection for (Line Item 1.6) the Substation Contamination Remediation.

A. During 2013 Gulf Power will be removing contaminated soils from the Highland City substation site. Substation equipment will be relocated in order to allow access for excavation of contaminated soils. Removal of impacted soils is the most cost effective means of remediation for that area of the site. The projected 2013 expenditures for this line item are $704,000.

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

A. As stated in previous filings, Gulf is determining whether the existing Plant Smith site properties make it feasible for injection of used reclaimed water. Both the test injection well and monitoring well required by the Florida Department of Environmental Protection (FDEP) have been installed. Gulf is currently in the testing phase of the project. Since the testing and evaluation process is not complete and a final agreement has not been reached with the applicable suppliers of reclaimed water, the decision to move forward with the project has not yet been made. During 2013, Gulf anticipates designing a pump system and conducting longer term testing of the well system. Based on the testing results, Gulf will make a final determination on whether to move forward with the Plant Smith Reclaimed Water project. If it is determined that the project should be pursued, additional activities such as installation of additional injection well(s), a pumping system, monitoring well(s) and permitting the wells as a class I injection system would take place. Costs associated with these activities reflected in the 2013 projection filing for this line item are $6.9 million.

Q. Mr. Vick, please describe the projected 2013 capital expenditures for the CAIR/CAMR/CAVR Compliance program (Line Item 1.26).

A. Gulf plans to add an additional catalyst layer to the Plant Crist Unit 6 SCR during 2014. A new catalyst layer will be purchased in late 2013 for installation during the spring of 2014 outage. The 2013 projected cost for this line item is $332,000.

Q. Mr. Vick, are you including the purchase of allowances in your 2013 projection filing?

A. No, we are not currently projecting the need to purchase additional allowances during 2013. On August 21, 2012, the D.C. Circuit Court of Appeals vacated and remanded the Cross State Air Pollution Rule (CSAPR) to EPA. It cannot be determined at this time what, if any, impact the court's action will have on Gulf's need for allowances.

Q. Mr. Vick, please provide an update on the status of the Daniel scrubber projects?

A. The Plant Daniel scrubber project team is continuing engineering design and is in the early stages of construction. The primary construction activities for this year include site preparation, relocations, and the installation of foundations required to support the Unit 1 and 2 absorber vessels and new stack. By year end 2012, the Plant Daniel scrubber project will be approximately 22% complete. During 2013, completion of the scrubber site development and installation of foundations are projected to take place. Fabrication of the stack liner and construction of the stack shell and absorber vessels will begin during 2013. Projected 2013 capital expenditures for Gulf's ownership portion of the Daniel scrubber project are $111 million. This project qualifies for AFUDC treatment and therefore these expenditures are not included in Gulf's projected 2013 ECRC factor.

Q. Mr. Vick, are there any other updates that you would like to discuss?

A. Yes, as discussed in the 2012 Environmental Compliance Program Update, Gulf Power is currently evaluating potential options to comply with the Mercury Air Toxics Standards (MATS) rule. Compliance with this rule is likely to require substantial capital expenditures and compliance costs at the Company's facilities. These costs may arise from unit retirements, installation of additional emission controls, changing fuel sources for certain existing units, the addition of new generating resources, and/or upgrades to the transmission system. The MATS rule also requires installation of additional continuous emission monitors and/or additional emissions testing. Once the Company determines the most cost-effective compliance options, Gulf will submit revisions to the Environmental Compliance Program for the Commission's review.

Q. How do the Environmental Operation and Maintenance (O&M) activities listed on Schedule 2P of Mr. Dodd's exhibit compare to the O&M activities approved for cost recovery in past ECRC proceedings?

A. All of the O & M activities listed on Schedule 2P have been approved for recovery through the ECRC in past proceedings.

Q. Please describe the O&M activities included in the air quality category that have projected expenses during 2013.

A. There are five O&M activities included in the air quality category that have projected expenses in 2013. On Schedule 2P, Air Emission Fees (Line Item 1.2), represents the expenses projected for the annual fees required by the Clean Air Act Amendments (CAAA) of 1990 that are payable to the FDEP and Mississippi Department of Environmental Quality. The expenses projected for the 2013 recovery period total $632,000.

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 2013 estimated expenses for the Title V Program are $125,044.

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 expenses projected for the recovery period total $900.

Emission Monitoring (Line Item 1.5) on Schedule 2P reflects an ongoing O&M expense associated with the Continuous Emission Monitoring equipment as required by the CAAA. These expenses are incurred in response to EPA's requirements that the Company perform Quality Assurance/Quality Control (QA/QC) testing for the CEMS, including Relative Accuracy Test Audits (RATAs) and Linearity Tests. The expenses expected to be incurred during the 2013 recovery period for these activities total $645,576.

The FDEP NOx Reduction Agreement (Line Item 1.19) includes O&M costs associated with the Plant Crist Unit 6 and Unit 7 SCRs and the Crist Units 4 and 5 Selective Non-Catalytic Reduction (SNCR) projects that were included as part of the 2002 agreement with FDEP. This line item includes the cost of anhydrous ammonia, urea, air monitoring, and general O&M expenses related to activities undertaken in connection with the agreement. Gulf was granted approval for recovery of the costs incurred to complete these activities in FPSC Order No. PSC-02-1396-PAA-EI in Docket No. 020943-EI. The projected expenses for the 2013 recovery period total $1.7 million.

Q. What O&M activities are included in the water quality category?

A. General Water Quality (Line Item 1.6), identified in Schedule 2P, includes costs associated with Soil Contamination Studies, Dechlorination, Groundwater Monitoring, Surface Water Studies, the Cooling Water Intake Program, the Impaired Waters Rule, and Storm Water Maintenance. The expenses expected to be incurred during the projection period for this line item totals $851,953.

Q. What other O&M activities are included in the water quality category?

A. Groundwater Contamination Investigation (Line Item 1.7) was previously approved for environmental cost recovery in Docket No. 930613-EI. This line item includes expenses related to substation investigation and remediation activities. Gulf has projected $2.2 million of incremental expenses for this line item during the 2013 recovery period.

Line Item 1.8, State National Pollutant Discharge Elimination System (NPDES) Administration, was previously approved for recovery in the ECRC and reflects expenses associated with NPDES annual fees for Gulf's three generating facilities in Florida. These expenses are expected to be $34,500 during the projected recovery period.

Finally, Line Item 1.9, Lead and Copper Rule, was also previously approved for ECRC recovery and reflects sampling, analytical, and chemical costs related to the lead and copper drinking water quality standards. These expenses are expected to total $16,480 during the 2013 projection period.

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

A. Only one O&M activity is included in this category on Schedule 2P (Line Item 1.10) of Mr. Dodd's exhibit. This line item refers to the Company's Environmental Audit/Assessment function. This program is an on-going compliance activity previously approved for ECRC recovery. Expenses totaling $7,000 are expected during the 2013 recovery period.

Q. What O&M activities are included in the General Solid and Hazardous waste category?

A. This solid and hazardous waste activity involves the proper identification, handling, storage, transportation, and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. This program is a previously approved program that is projected to incur incremental expenses totaling $469,157 in 2013.

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

A. There are five other O&M activities that have been approved in past proceedings which have projected expenses during 2013. They are the Above Ground Storage Tanks program, the Sodium Injection System, the CAIR/CAMR/CAVR Compliance Program, Crist Water Conservation, and Emission Allowances.

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

A. Above Ground Storage Tanks (Line Item 1.12) includes maintenance activities and fees required by Florida's above ground storage tank regulation, Chapter 62 Part 762, F.A.C. Expenses totaling $186,582 are projected to be incurred during 2013.

Q. What activity is included in the Sodium Injection line item?

A. The Sodium Injection System (Line Item 1.16) was originally approved for inclusion in the ECRC in Order No. PSC-99-1954-PAA-EI. The activities in this line item involve sodium injection to the coal supply that enhances precipitator efficiencies when burning certain low sulfur coals at Plant Crist and Plant Smith. Expenses totaling $74,000 are projected to be incurred during 2013 for this line item.

Q. What activities are included in the CAIR/CAMR/CAVR Compliance Program (Line Item 1.20)?

A. This line item includes O&M expenses associated with the capital projects approved for ECRC recovery under the CAIR/CAMR/CAVR Compliance Program. The projected 2013 expenses for this line item total approximately $16.5 million which includes $7.9 million for limestone costs associated with operation of the Plant Crist scrubber.

Q. What activities are included in the Crist Water Conservation line item (Line Item 1.22)?

A. The Crist Water Conservation line item includes general O&M expenses associated with the Plant Crist reclaimed water system, such as piping and valve maintenance and pump replacements. Expenses totaling $291,840 are projected to be incurred during 2013 for this line item.

Q. Please describe the emission allowance line items 1.24 and 1.26.

A. These line items include projected allowance expenses for Gulf's generation. Line Items 1.24 and 1.26 include projected expenses for Annual NOx and SO_2 emission allowances of $412,304 and $602,887, respectively.

Q. Do each of the capital projects and O&M activities that have projected costs in 2013 meet the ECRC statutory guidelines?

A. Yes. The projects included in Gulf's 2013 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. Dodd's schedules include only prudent costs that are not recovered through some other cost recovery mechanism or base rates. The projected environmental costs are necessary to achieve and/or maintain compliance with environmental laws, rules, and regulations.

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

A. Yes.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 120007-EI
Date of Filing: April 2, 2012

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

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

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator.

In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Rates and Regulatory Matters area. My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. 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 2011 through December 2011 for the Environmental Cost Recovery Clause (ECRC).

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

A. Yes, I have.

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

Q. Are you familiar with the ECRC true-up calculation for the period January through December 2011 set forth in your exhibit?

A. Yes. These documents were prepared under my supervision.

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

A. Yes.

Q. What is the amount to be refunded or collected in the recovery period beginning January 2013?

A. An amount to be collected of $5,275,632 was calculated, which is reflected on line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $5,275,632 to be collected was calculated by taking the difference between the estimated January 2011 through December 2011 over-recovery of $14,380,513 as approved in FPSC Order No. PSC-11-0553-FOF-EI, dated December 7, 2011, and the actual over-recovery of $9,104,881, 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 2011 through December 2011. Schedule 3A of my exhibit is the calculation of the interest provision on the average true-up balance. This is the same method of calculating interest that is used in the Fuel Cost Recovery and Purchased Power Capacity Cost Recovery clauses.

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

A. Schedule 4A compares the actual O&M expenses for the period January 2011 through December 2011 with the estimated/actual O&M expenses approved in conjunction with the November 2011 hearing. Schedule 5A shows the monthly O&M expenses by activity, along with the calculation of jurisdictional O&M expenses for the recovery period. Emission allowance expenses and the amortization of gains on emission allowances are included with O&M expenses. Any material variances in O&M expenses are discussed in Mr. Vick's final true-up testimony.

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

A. Schedule 6A for the period January 2011 through December 2011 compares the actual recoverable costs related to investment with the estimated/actual amount approved in conjunction with the November 2011 hearing. The recoverable costs include the return on investment, depreciation and amortization expense, dismantlement accrual, and property taxes associated with each environmental capital project for the recovery period. Recoverable costs also include a return on working capital associated with emission allowances. Schedule 7A provides the monthly recoverable costs associated with each project, along with the calculation of the jurisdictional recoverable costs. Any material variances in recoverable costs related to environmental investment for this period are discussed in Mr. Vick's final true-up testimony.

Q. Please describe Schedule 8A of your exhibit.

A. Schedule 8A includes 31 pages that provide the monthly calculations of the recoverable costs associated with each approved capital project for the recovery period. As I stated earlier, these costs include return on investment, depreciation and amortization expense, dismantlement accrual, property taxes, and the cost of emission allowances. Pages 1 through 27 of Schedule 8A show the investment and associated costs related to capital projects, while pages 28 through 31 show the investment and costs related to emission allowances.

Q. Mr. Dodd, what capital structure, components and cost rates did Gulf use to calculate the revenue requirement rate of return?

A. In accordance with FPSC Order No. PSC-94-0044-FOF-EI, the rate of return used to develop the revenue requirements associated with ECRC investment is based on the capital structure and cost rates approved in Docket No. 010949-EI, FPSC Order No. PSC-02-0787-FOF-EI, dated June 10, 2002 which were in effect for 2011. Please see Schedule 9 of my exhibit for the derivation of debt and equity components.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 120007-EI
Date of Filing: August 1, 2012

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

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

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator.

In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Rates and Regulatory Matters area. My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. 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 2012 through December 2012 for the Environmental Cost Recovery Clause (ECRC).

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes, I have. My exhibit consists of nine schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Dodd's exhibit consisting of nine schedules be marked as Exhibit No. _____(RWD-2).

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

Q. What has Gulf calculated as the estimated true-up for the January 2012 through December 2012 period to be refunded or collected in the period January 2013 through December 2013?

A. The estimated true-up for the current period is an over-recovery of $7,453,359 as shown on Schedule 1E. This is based on six months of actual data and six months of estimated data. This amount will be added to the 2011 final true-up under-recovery amount of $5,275,632. The sum of $2,177,727 will be refunded to customers during the January 2013 through December 2013 period. The detailed calculations supporting the estimated true-up for 2012 are contained in Schedules 2E through 8E.

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

A. Schedule 2E shows the calculation of the estimated over-recovery of environmental costs for the period January 2012 through December 2012. Schedule 3E of my exhibit is the calculation of the interest provision on the average true-up balance. This is the same method of calculating interest that is used in the Fuel Cost Recovery and Purchased Power Capacity Cost Recovery clauses.

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

A. Schedule 4E compares the estimated/actual O&M expenses for the period January 2012 through December 2012 to the projected O&M expenses approved by the Commission in Docket No. 110007-EI. Schedule 5E shows the monthly O&M expenses by activity, along with the calculation of jurisdictional O&M expenses for the current recovery period. Per the

Staff's request, emission allowance expenses and the amortization of gains on emission allowances are included with O&M expenses. Mr. Vick describes the main reasons for the expected variances in O&M expenses in his true-up testimony.

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

A. Schedule 6E for the period January 2012 through December 2012 compares the estimated/actual recoverable costs related to investment to the projected amount approved in Docket No. 110007-EI. The recoverable costs include the return on investment, depreciation and amortization expense, dismantlement accrual, and property taxes associated with each environmental capital project for the current recovery period. Recoverable costs also include a return on working capital associated with emission allowances. Schedule 7E provides the monthly recoverable revenue requirements associated with each project, along with the calculation of the jurisdictional recoverable revenue requirements. Mr. Vick describes the major variances in recoverable costs related to environmental investment for this estimated true-up period in his testimony.

Q. Please describe Schedule 8E of your exhibit.

A. Schedule 8E includes 31 pages that provide the monthly calculations of recoverable costs associated with each approved capital investment for the current recovery period. As stated earlier, these costs include return on investment, depreciation and amortization expense, dismantlement accrual, property taxes, and the return on working capital associated with emission allowances. Pages 1 through 27 of Schedule 8E show the investment and associated costs related to capital projects, while pages 28 through 31 show the investment and return related to emission allowances.

Q. What capital structure and return on equity were used to develop the rate of return used to calculate the revenue requirements as shown on Schedule 9E?

A. Consistent with Commission policy, the capital structure used in calculating the rate of return for recovery clause purposes is based on the capital structure approved in Gulf's last completed rate case. For the period January 2012 through April 10, 2012, the rate of return for the ECRC is based on the capital structure approved in Docket No. 010949-EI, FPSC Order No. PSC-02-0787-FOF-EI dated June 10, 2002. Gulf's new base rates resulting from its recent base rate case, Docket No. 110138-EI, were effective April 11, 2012. Therefore, the rate of return used to calculate the ECRC revenue requirements for the period April 11, 2012 through December 31, 2012 is based on the capital structure and a return on equity of 10.25% approved in this proceeding.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 120007-EI
Date of Filing: August 28, 2012

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

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

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator. In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Rates and Regulatory Matters area. My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present both the calculation of the revenue requirements and the development of the environmental cost recovery factors for the period of January 2013 through December 2013.

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

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

Counsel: We ask that Mr. Dodd's exhibit consisting of eight schedules be marked as Exhibit No. _____(RWD-3).

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

A. As discussed in the testimony of J. O. Vick, Gulf is requesting recovery for certain environmental compliance operating expenses and capital costs that are consistent with both the decision of the Commission in Order No. PSC-94-0044-FOF-EI in Docket No. 930613-EI and with past proceedings in this ongoing recovery docket. The costs we have identified for recovery through the ECRC are not currently being recovered through base rates or any other cost recovery mechanism.

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

A. Mr. Vick has provided me with projected recoverable O&M expenses for January 2013 through December 2013. Schedule 2P of my exhibit 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 the Clean Air Act Amendments of 1990 (CAAA) were considered to be energy-related, consistent with Commission Order No. PSC-94-0044-FOF-EI. O&M expenses associated with Gulf's Clean Air Interstate Rule (CAIR) and Clean Air Visibility Rule (CAVR) Compliance Program were considered to be energy-related pursuant to FPSC Order No. PSC-06-0972-FOF-EI issued November 22, 2006. The remaining expenses were broken down between demand and energy consistent with Gulf's last approved cost-of-service methodology in Docket No. 110138-EI.

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

A. Schedule 3P summarizes the monthly recoverable revenue requirements associated with each capital investment project for the recovery period. Schedule 4P shows the detailed calculation of the revenue requirements associated with each investment project. These schedules also include the calculation of the jurisdictional amount of recoverable revenue requirements. Mr. Vick has provided me with the expenditures, clearings, retirements, salvage, and cost of removal related to each capital project as well as the monthly costs for emission allowances. From that information, plant-in-service and construction work in progress (non interest bearing) was calculated. Additionally, depreciation, amortization and dismantlement expense and the associated accumulated depreciation balances were calculated based on Gulf's approved depreciation rates, amortization periods, and dismantlement accruals. The capital projects identified for recovery through the ECRC are those environmental projects which were not included in the approved January 2012 through December 2012 test year on which present base rates were set.

Q. How was the amount of property taxes to be recovered through the ECRC derived?

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

Q. What capital structure and return on equity were used to develop the rate of return used to calculate the revenue requirements as shown on 8P?

A. Consistent with Commission Order No. PSC-12-0425-PAA-EU dated August 16, 2012 in Docket No. 120007-EI, the capital structure used in calculating the rate of return for recovery clause purposes is based on the weighted average cost of capital (WACC) presented in Gulf's May 2012 Earnings Surveillance Report. This rate of return used to calculate ECRC revenue requirements includes a return on equity of 10.25% for the period January 1, 2013 through December 31, 2013.

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

A. The investment costs associated with compliance with the CAAA were considered to be energy-related consistent with Commission Order No. PSC-94-0044-FOF-EI, dated January 12, 1994, in Docket No. 930613-EI. The investment costs associated with Gulf's CAIR and CAVR Compliance Program were considered to be energy-related pursuant to FPSC Order No. PSC-06-0972-FOF-EI issued November 22, 2006. The remaining investment costs of environmental compliance were allocated 12/13th based on demand and 1/13th based on energy, consistent with Gulf's last approved cost-of-service study. The calculation of this breakdown is shown on Schedule 4P and summarized on Schedule 3P.

Q. What is the total amount of projected recoverable costs related to the period January 2013 through December 2013?

A. The total projected jurisdictional recoverable costs for the period January 2013 through December 2013 is $141,059,079 as shown on line 1c of Schedule 1P. This includes costs related to O&M activities of $23,951,253 and costs related to capital projects of $117,107,826 as shown on lines 1a and 1b of Schedule 1P.

Q. What is the total recoverable revenue requirement to be recovered in the projection period January 2013 through December 2013 and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $138,981,347 for the period January 2013 through December 2013 as shown on line 5 of Schedule 1P. This amount includes the recoverable costs related to the projection period and the total true-up cost of $2,177,727 to be refunded. Schedule 1P also summarizes the energy and demand components of the requested revenue requirement. These amounts are allocated by rate class using the appropriate energy and demand allocators as shown on Schedules 6P and 7P.

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

A. The demand allocation factors used in the ECRC were calculated using the 2009 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The energy allocation factors were calculated based on projected KWH sales for the period adjusted for losses. The calculation of the allocation factors for the period is shown in columns 1 through 9 on Schedule 6P.

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

A. As I described earlier in my testimony, Schedule 1P summarizes the energy and demand portions of the total requested revenue requirement. The energy-related recoverable revenue requirement of $130,648,326 for the period January 2013 through December 2013 was allocated using the energy allocator, as shown in column 3 on Schedule 7P. The demand-related recoverable revenue requirement of $8,333,020 for the period January 2013 through December 2013 was allocated using the demand allocator, as shown in column 4 on Schedule 7P. The energy-related and demand-related recoverable revenue requirements are added together to derive the total amount assigned to each rate class, as shown in column 5.

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

A. The environmental costs recovered through the clause from the residential customer who uses 1,000 kWh will be $12.53 monthly for the period January 2013 through December 2013.

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 2013 and will continue through the last billing cycle of December 2013.

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

A. Yes.

CHAIRMAN BRISÉ: All right. I think we are at a point, again, where we can make a decision. Is there a motion?

COMMISSIONER BALBIS: Yes, Mr. Chairman. I move that we approve all issues as stipulated in Docket Number 120007-EI.

CHAIRMAN BRISÉ: Okay. Thank you. Is there a second?

COMMISSIONER EDGAR: Second.

CHAIRMAN BRISÉ: Okay. It has been moved and seconded.

Any questions? Okay. Seeing none, all in favor say aye.

(Vote taken.)

CHAIRMAN BRISÉ: Okay. Seeing that we have made a bench decision on this docket, there is no need for post-hearing filings. The final order will be issued December 1, 2012.

Thank you very much. Now we'll adjourn Docket Number 120007.

(The hearing concluded at 9:51 a.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, 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 8th day of November, 2012.

JANE FAUROT, RPR
FPSC Official Commission Reporter
(850) 413-6732