BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 150001-EI

FUEL AND PURCHASED POWER COST
RECOVERY CLAUSE WITH
GENERATING PERFORMANCE
INCENTIVE FACTOR.
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VOLUME 1

(Pages 1 through 220)

PROCEEDINGS: HEARING

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

DATE: Monday, November 2, 2015

TIME: Commenced at 1:31 p.m.
Concluded at 1:38 p.m.

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

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

APPEARANCES:

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

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

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

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

ROBERT SCHEFFEL WRIGHT and JOHN T. LaVIA, III, ESQUIRES, Gardner Law Firm, 1300 Thomaswood Drive, Tallahassee, Florida 32308, appearing on behalf of the Florida Retail Federation.

APPEARANCES (Continued):

BETH KEATING, ESQUIRE, Gunster Law Firm, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1839, appearing on behalf of Florida Public Utilities Company.

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

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

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

APPEARANCES (Continued):

SUZANNE BROWNLESS, DANIJELA JANJIC, and JOHN VILLAFRATE, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission.

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

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

I N D E X

WITNESSES

EXHIBITS

NUMBER: ID. ADMTD.

No exhibits marked or admitted in this volume

P R O C E E D I N G S

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

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

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

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

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

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

CHAIRMAN GRAHAM: Thank you.

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

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

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

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

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

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

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

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

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

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

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

MR. BECK: And Charlie Beck, General Counsel.

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CHAIRMAN GRAHAM: Okay. Let's come to order. Just to let you know how the next couple of days are going to play out. We've had a little scheduling snafu, so we're going to try to end today probably by 6:00, 6:30, so we won't be taking a dinner break. We should be, as normal, stopping every two hours or so for our court reporter to rest her little fingers.

Tomorrow we start at, I believe at 7:00 -- I'm sorry, 9:30. We start at 9:30. We will take a break for lunch, I'm guessing, sometime around 1:00-ish. We'll probably take a break for dinner I'm guessing sometime around 6:30-ish. And I would say bring your nightcap because we're probably going to go pretty late.

On Wednesday, we need to finish up on Wednesday, so we'll go Wednesday until we finish. We do have the afternoon on Thursday if for some reason we have to go to that, but so anticipate going late both Tuesday and Wednesday. Hopefully we don't have to go late at all on Wednesday, but it all depends on how it goes. We're doing things a little different this time, so we've got to kind of feel our way through them, and so I just ask your patience as we get through those -- as we work our way through that. Is there any questions or concerns or comments before we open the 01 docket? Fantastic.

All right. So let's open the 01 docket. Staff, preliminary matters.

MS. BROWNLESS: Yes, sir. The Prehearing Order does not list any stipulations; however, stipulations were entered into after the Prehearing Order was issued. A notice of stipulations and notice of issues and witnesses, should the stipulations be approved, were filed in the docket on October 30th of 2015.

We recommend that the proposed stipulations provided to Commissioners and parties be approved by the Commission. These stipulations are all Type 2 stipulations as some parties have taken no position on the issues. These stipulations have also been entered into with the understanding that should the Commission discontinue hedging, appropriate adjustments will be made in the next year's fuel docket to reflect the Commission's decision.

There are some minor corrections to the stipulations for FP&L's positions stated on the notice of stipulations filed on October 30th that need to be made. These are with regard to Issue 2C. It should read "$12,976,120" not -- oh, 3C. I'm sorry, forgive me -- not "$12,976,102."

Issue 3E should read "2,259,985," not "2,259,986."

Issue 21 should read, "FPL is proposing the following separate factors for January 2016 through May 2016 and for June 2016 through December 2016," not "FPL is proposing the following separation factors for January 2016 through May 2016 and for June 2016 through December 2016."

The issues that remain in contention for all parties are 1B, 1E, 2B, 3B, 3K, 4A, 4B, 5B, and 6B. Additionally, the issues that also remain in contention for FPUC are Issues 9 through 12, 19, 21, and 23. We recommend that for the stipulated issues identified on the notice of stipulations that a bench vote be taken.

CHAIRMAN GRAHAM: Commissioners, any questions of staff?

Commissioner Edgar.

COMMISSIONER EDGAR: Mr. Chairman, I do not have a question, but I'll be ready to offer a motion when you are ready for it.

CHAIRMAN GRAHAM: Anybody else? Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman. For the 01 docket I move approval of all issues listed on the notice of stipulations with the additional scrivener's error corrections to Issue 3C, Issue 3E, and Issue 21.

COMMISSIONER BROWN: Second.

CHAIRMAN GRAHAM: It's been moved and seconded. We will call it the Edgar motion. Any further discussion? Seeing none, all in favor, say aye.

(Vote taken.)

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

Okay. Comprehensive Exhibit List, staff.

MS. BROWNLESS: Yes, sir. At this time staff requests that staff's Comprehensive Exhibit List be marked for identification as Exhibit 1. This list was provided to the parties by email on Friday, October 30th.

CHAIRMAN GRAHAM: Okay.

MS. BROWNLESS: With regard to prefiled testimony and exhibits for excused witnesses, the parties have stipulated to the excusal of these witnesses and to the insertion into the record of the prefiled testimony of DEF witness Matthew Jones, Jeffrey Swartz, and Christopher Menendez; Gulf witness C. L. Nicholson and C. S. Boyette; TECO witnesses Brian Buckley, B. F. Smith, and Penelope Rusk; FPL witnesses C. R. Rote, Don Grissette, and Terry Keith; and staff witnesses Simon Ojada, Intesar Terkawi, and George Simmons. Staff would ask that this testimony be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert the testimony into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 150001-EI

MARCH 3, 2015

Q. Please state your name, business address, employer and position.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida, 33174. I am employed by Florida Power & Light Company (FPL or the Company) as the Director, Cost Recovery Clauses, in the Regulatory & State Governmental Affairs Department.

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

A. Yes.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery (FCR) Clause and Capacity Cost Recovery (CCR) Clause Net True-Up amounts for the period January 2014 through December 2014. The Net True-Up for the FCR is an over-recovery, including interest, of $10,088,837. The Net True-Up for the CCR is an under-recovery, including interest, of $2,951,171. FPL is requesting Commission approval to include the FCR true-up over-recovery of $10,088,837 in the calculation of the FCR factors for the period January 2016 through December 2016. FPL is also requesting Commission approval to include the CCR true-up under-recovery of $2,951,171 in the calculation of the CCR factors for the period January 2016 through

December 2016. Finally, FPL is requesting Commission approval to include $12,976,120 in the calculation of the FCR factors for the period January 2016 through December 2016, which represents FPL's share of the 2014 Incentive Mechanism gain described in the testimony of FPL witness Yupp.

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

A. Yes, I have. It consists of two appendices. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules. In addition, FCR Schedules A1 through A12 for the January 2014 through December 2014 period have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

Q. What is the source of the data you present?

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 the Company's business in accordance with generally accepted accounting principles and practices, and with the applicable provisions of the Uniform System of Accounts as prescribed by the Commission.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the FCR net true-up amount.

A. Appendix I, page 1, titled "Summary of Net True-Up," shows the calculation of the Net True-Up for the period January 2014 through December 2014, an over-recovery of $10,088,837.

The Summary of the Net True-up amount shows the actual End-of-Period True-Up under-recovery for the period January 2014 through December 2014 of $256,473,369 on line 1. The Actual/Estimated True-Up under-recovery for the same period of $266,562,206 is shown on line 2. Line 1 less line 2 results in the Net Final True-Up for the period January 2014 through December 2014, an over-recovery of $10,088,837 on line 3.

The calculation of the true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision."

Q. Have you provided a schedule showing the calculation of the 2014 FCR actual true-up by month?

A. Yes. Appendix I, page 2, titled "Calculation of Final True-up Amount," shows the calculation of the FCR actual true-up by month for January 2014 through December 2014.

Q. Have you provided schedules showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2014?

A. Yes. Appendix I, page 3, provides a comparison of jurisdictional fuel costs and revenues on a dollar per MWh basis. Appendix I, page 4, compares the actual End-of-Period True-up under-recovery of $256,571,851 to the Actual/Estimated End-of-Period True-up under-recovery of $266,660,688. Both comparisons result in a net over-recovery of $10,088,837.

Q. Please describe the variance analysis on page 3 of Appendix I.

A. Appendix I, page 3, provides a comparison of Jurisdictional Total Fuel Revenues and Jurisdictional Total Fuel Costs (including Net Power Transactions) on a dollar per MWh basis.

The $10,088,837 over-recovery is primarily due to a decrease in fuel prices resulting in a variance of $9,054,297 and a decrease in consumption resulting in a variance of $1,045,445.

Actual jurisdictional fuel revenues collected were $36,014,173 lower than projected and actual consumption was 1,125,767 MWh lower than projected, yet revenues collected per MWh were $0.00787 higher than projected. Of the $36,014,173 decrease in fuel revenues collected, $36,835,405 was due to the decrease in consumption, partly offset by a slight increase in price (revenues per MWh) of $821,232.

Actual jurisdictional fuel costs were $46,113,915 lower than projected, jurisdictional fuel costs per MWh were $0.07887 lower than projected, and actual consumption was 1,125,767 MWh lower than projected. Of the $46,113,915 decrease in jurisdictional fuel costs, $37,880,850 was due to the decrease in consumption and $8,233,065 was due to the decrease in price (fuel costs incurred per MWh).

The decrease in fuel revenues due to consumption of $36,835,405 minus the decrease in jurisdictional fuel costs due to consumption of $37,880,850 resulted in a variance due to consumption of $1,045,445. The increase in fuel revenues due to price of $821,232 minus the decrease in fuel costs due to price of $8,233,065 resulted in a variance due to price of $9,054,297. The variance due to consumption of $1,045,445 and the variance due to price of $9,054,297 resulted in an over-recovery of $10,099,742. This over-recovery of $10,099,742 plus the decrease of $10,905 in interest associated with the 2014 final true-up amount resulted in a total true up over-recovery of $10,088,837.

Q. Turning to page 4 in Appendix I, what was the variance in Adjusted Total Fuel Costs and Net Power Transactions?

A. The variance in Adjusted Total Fuel Costs and Net Power Transactions was a decrease of $38,030,582. This decrease was primarily due to a $44.8 million decrease in Fuel Cost of System Net Generation, a $15.7 million decrease in Energy Payments to Qualifying Facilities (QFs), a $3.2 million increase in Gains from Off-System Sales, a $1.0 million increase in the Fuel Cost of Power Sold, a $0.8 million increase in Energy Imbalance Fuel Revenues, and a $0.2 million decrease in Inventory Adjustments. These amounts were partially offset by a $19.1 million increase in Fuel Cost of Purchased Power, a $7.0 million increase in Energy Cost of Economy Purchases, a $1.2 million increase in Non-Recoverable Oil/Tank Bottoms, and a $0.4 million increase in the Variable Power Plant O&M Costs.

<u>Fuel Cost of System Net Generation ($44.8 million decrease)</u>

FPL's coal cost averaged $2.92 per MMBtu, which was $0.14 per MMBtu or 5.1% higher than projected during the period. However, FPL consumed 8,292,018 less MMBtus (14.7%) than projected during the period. Of the total

$16.3 million decrease for coal, $23.1 million was due to lower than projected consumption, partially offset by a $6.8 million increase due to higher than projected unit costs.

FPL's natural gas cost averaged $5.29 per MMBtu, which was $0.13 per MMBtu or 2.49% lower than projected during the period. However, FPL consumed 12,046,706 more MMBtus (2.11%) than projected during the period. Of the total $13.3 million decrease for natural gas, $78.7 million was due to lower than projected unit costs, partially offset by a $65.3 million increase due to higher than projected consumption.

FPL's heavy oil cost averaged $14.70 per MMBtu, which was $0.01 per MMBtu or 0.05% higher than projected during the period. However, FPL consumed 845,951 less MMBtus (24.7%) than projected during the period. Of the total $12.4 million decrease for heavy oil, $12.4 million was due to lower than projected consumption, slightly offset by a $17,190 increase due to higher than projected unit costs.

FPL's light oil cost averaged $20.84 per MMBtu, which was $0.21 per MMBtu or 0.98% lower than projected during the period. Additionally, FPL consumed 90,989 less MMBtus (7.4%) than projected during the period. Of the total $2.2 million decrease for light oil, $1.9 million was due to lower than projected consumption and $0.2 million was due to lower than projected unit costs.

FPL's nuclear fuel cost averaged $0.63 per MMBtu, which was $0.01 per MMBtu or 1.4% lower than projected during the period. However, FPL consumed 3,219,898 more MMBtus (1.1%) than projected during the period. Of the total $0.7 million decrease for nuclear, $2.7 million was due to lower than projected unit costs, partially offset by a $2.0 million increase due to higher than projected consumption.

Energy Payments to Qualifying Facilities ($15.7 million decrease)

The variance for Energy Payments to QFs was attributable to both lower than projected QF purchases and lower than projected unit costs for those purchases. FPL purchased approximately 315,000 MWh less from QF facilities. Lower purchases resulted in a variance of approximately $12.8 million or 82% of the total variance. The fuel cost of QF purchases was approximately $1.15/MWh less than projected. Lower than projected fuel costs resulted in a variance of approximately $2.9 million, or 18% of the total variance. The combination of lower volume and lower fuel costs resulted in a total variance of $15.7 million lower than projected QF energy costs.

Gains from Off-System Sales ($3.2 million increase)

The variance for Gains from Off-System Sales was primarily due to higher than projected economy sales. FPL sold approximately 396,500 MWh more of economy power than projected, which resulted in a variance of approximately $8.1 million. This variance was partially offset by a lower than projected average margin on economy sales of $1.98/MWh which resulted in a variance of approximately $4.9 million.

Fuel Cost of Power Sold ($1.0 million increase)

The variance for Fuel Cost of Power Sold was primarily due to higher than projected economy sales, partially offset by lower than projected fuel costs for economy sales. FPL sold approximately 396,500 MWh more of economy power than projected, which resulted in a variance of approximately $14.6 million. The lower fuel costs of economy sales, $31.22/MWh versus a projection of $36.86/MWh, resulted in a partially offsetting variance of approximately $14.1 million. This variance is increased by $0.4 million primarily due to higher than projected sales related to the St. Lucie Reliability Exchange. FPL sold approximately 67,000 more MWh through the agreement than originally projected.

Fuel Cost of Purchased Power ($19.1 million increase)

The variance for Fuel Cost of Purchased Power is primarily due to higher than projected utilization of the UPS power agreements. Total costs for UPS purchases were approximately $21.9 million higher than projected. Of the $21.9 million variance, approximately $19.8 million was due to approximately 455,000 MWh higher UPS purchases and approximately $2.1 million was due to higher fuel costs, $44.18/MWh versus a projection of $43.44/MWh. FPL executed a power purchase agreement with Seminole Electric in August, which was not included in the previous projections and resulted in a variance of approximately $0.5 million. St. Lucie purchases resulted in a total cost variance of approximately $0.2 million.

FPL purchased approximately 17,000 more MWh than projected, while the overall unit cost was $0.13/MWh higher than originally projected. The UPS variance was partially offset by lower than projected purchases from SJRPP. The total costs for SJRPP purchases were approximately $3.4 million lower than projected. FPL purchased approximately 106,000 MWh lower than projected, while the overall unit cost was $0.17/MWh higher than projected.

Energy Cost of Economy Purchases ($7.0 million increase)

The variance for Energy Cost of Economy Purchases is primarily attributable to higher than projected economy purchases. FPL purchased approximately 141,000 MWh more of economy energy than projected. Higher economy purchases resulted in a volume variance of approximately $7.0 million, or 101% of the total variance. The costs of economy purchases were on average $0.21/MWh lower than projected, resulting in an offsetting variance of approximately $88,000, or 1% of the total variance.

Variable Power Plant O&M Costs ($0.4 million increase)

Variable Power Plant O&M Costs are driven by sales volumes in excess of the 514,000 MW threshold applicable to the Incentive Mechanism. The variance is primarily due to higher sales of economy power. FPL sold approximately 396,500 MWh more economy power than originally projected.

Q. What was the variance in retail (jurisdictional) FCR revenues?

A. As shown on Appendix I, page 4, line 30, actual jurisdictional FCR revenues, net of revenue taxes, were approximately $36.0 million or 1.0% lower than the actual/estimated projection. This was primarily due to lower than projected jurisdictional sales, which were approximately 1,125,767,272 kWh, or 1.1% lower than the actual/estimated projection.

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $12,976,120 as its 60% share of 2014 Incentive Mechanism gains over the $46 million threshold. When is FPL requesting to recover its share of the gains, and how will this be reflected in the FCR schedules?

A. FPL is requesting recovery of its share of the 2014 Incentive Mechanism gains through the 2016 FCR factors, consistent with its treatment of approved Generating Performance Incentive Factor (GPIF) amounts. FPL will include the approved Incentive Mechanism amount in the calculation of the 2016 FCR factors and will reflect recovery of one-twelfth of the approved amount, net of revenue taxes, in each month's Schedule A2 for the period January 2016 through December 2016 as a reduction to jurisdictional fuel revenues applicable to each period.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the CCR net true-up amount.

A. Appendix II, page 1, titled "Summary of Net True-Up" shows the calculation of the CCR Net True-Up for the period January 2014 through December 2014, an under-recovery of $2,951,171, which FPL is requesting to be included in the calculation of the CCR factors for the January 2016 through December 2016 period.

The actual End-of-Period over-recovery for the period January 2014 through December 2014 of $7,348,039 shown on line 1 less the Actual/Estimated End-of-Period over-recovery for the same period of $10,299,210 shown on line 2 that was approved by the Commission in Order No. PSC-14-0701-FOF-EI, results in the Net True-Up under-recovery for the period January 2014 through December 2014 of $2,951,171 on line 3.

Q. Have you provided a schedule showing the calculation of the CCR actual true-up by month?

A. Yes. Appendix II, page 2, titled "Calculation of Final True-up" shows the calculation of the CCR End-of-Period true-up for the period January 2014 through December 2014 by month.

Q. Is this true-up calculation consistent with the true-up methodology used for the FCR clause?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" for the FCR clause.

Q. Have you provided a schedule showing the variances between actual and actual/estimated capacity charges and applicable revenues for 2014?

A. Yes. Appendix II, page 3, titled "Calculation of Final True-up Variances," shows the actual capacity charges and applicable revenues compared to actual/estimated capacity charges and applicable revenues for the period January 2014 through December 2014.

Q. What was the variance in net capacity charges?

A. Appendix II, page 3, line 15 provides the variance in Jurisdictional Capacity Charges, which is a decrease of $4,892,590 or 0.9%. This $4.9 million decrease was primarily due to a $6.1 million decrease in Incremental Plant Security - O&M, a $1.6 million decrease in Transmission of Electricity by Others, and a $0.1 million decrease in Incremental Plant Security - Capital. These decreases were partially offset by a $2.0 million increase in Payments to Non-cogenerators, and an increase of $0.8 million in Incremental Nuclear NRC Compliance (Fukushima) - O&M.

<u>Incremental Power Plant Security Costs - O&M ($6.1 million decrease)</u>

The $6.1 million decrease was primarily due to the nuclear cyber security plan implementation date being deferred from December 2015 to December 2017. FPL requested approval of the extension from the Nuclear Regulatory Commission (NRC), which is anticipated in 2015. Industry representatives have developed better guidance on how to implement the NRC's cyber security rule and NRC endorsement of the additional guidance is expected in 2015. As a result, FPL deferred some of the cyber security work that was planned for 2014 pending finalization of that guidance. NERC Critical Infrastructure Protection (CIP) and Cyber Security Distributed Control System (DCS) upgrades were deferred to 2015 due to regulatory uncertainty and implementation logistics. Additionally, initiatives related to the development of procedures and processes for the implementation of CIP versions 4 and 5 were deferred due to regulatory changes and final rule development.

Transmission of Electricity by Others ($1.6 million decrease)

The approximately $1.6 million variance is due to higher than projected utilization of the UPS power agreements, resulting in lower than projected unutilized transmission costs. FPL utilized approximately 455,000 MWh more than projected for the last five months of 2014.

Incremental Power Plant Security Costs - Capital ($0.1 million decrease)

The $0.1 million decrease is primarily due to the deferral of in-service dates for the St. Lucie Force-On-Force modifications from December 2014 to December 2015. The modifications were delayed pending the results of the graded Force on Force exercise performed by the NRC in October 2014 in order to determine if any changes to the scope of the project are required. Additionally, savings were realized at the Manatee plant for infrastructure upgrades and a portion of the planned scope of work was deferred to 2015. Finally, milestone payments at the West County plant were deferred to 2015.

Payments to Non-Cogenerators ($2.0 million increase)

The $2.0 million increase was primarily due to costs associated with the SJRPP agreement. Approximately $1.7 million of the total variance was attributable to the SJRPP agreement. An increase in costs of approximately $3.3 million for Cumulative Capital Recovery Amount (CCRA) payments was partially offset by lower payments for property taxes $720,000, decommissioning $116,000, O&M $627,000, and inventory expense charges to FPL $185,000. There was a small increase in costs of approximately $122,000 due to a Capacity Availability

Performance Adjustment (CAPA) true-up payment related to the Harris unit in the UPS agreement. In addition, FPL executed a purchased power agreement with Seminole Electric Cooperative, Inc. in August. That transaction resulted in a variance of approximately $194,000 as the purchase was not included in 2014 projections.

Incremental Nuclear NRC Compliance Costs (Fukushima) – O&M ($0.8 million increase)

The $0.8 million increase was primarily due to higher than projected Regional Response Center program fees and additional scope to ensure potential flooding hazards do not impact plant safety equipment at the St. Lucie plant.

Q. What was the variance in CCR revenues?

A. As shown on page 3, line 16, actual Capacity Cost Recovery Revenues (Net of Revenue Taxes) were $7,844,243 or 1.3% lower than the actual/estimated projection. This was primarily due to lower than projected jurisdictional sales, which were approximately 1,125,767,272 kWh, or 1.1% lower than the actual/estimated projection.

Q. Have you provided Schedule A12 showing the actual monthly capacity payments by contract?

A. Yes. Schedule A12 consists of two pages that are included in Appendix II as pages 4 and 5. Page 4 shows the actual capacity payments for FPL's Purchase Power Agreements for the period January 2014 through December 2014. Page 5 provides the Short Term Capacity Payments for the period January 2014 through December 2014.

Q. Have you provided a schedule showing the capital structure components and cost rates relied upon by FPL to calculate the rate of return applied to all capital projects recovered through the FCR and CCR clauses?

A. Yes. The capital structure components and cost rates used to calculate the rate of return on the capital investments for the period January 2014 through December 2014 are included on pages 10 and 11 of Appendix II.

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. 150001-EI

AUGUST 4, 2015

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the calculation of the Actual/Estimated True-up amounts for the Fuel Cost Recovery ("FCR") Clause and the Capacity Cost Recovery ("CCR") Clause for the period January 2015 through December 2015.

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

A. Yes, I have. It consists of various schedules included in Appendices I and II. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules.

The FCR Schedules contained in Appendix I include Schedules E3 through E9 that provide revised estimates for the period July 2015 through December 2015. Also included in the FCR Schedules is FPL's Gas Reserves Revenue Requirement Schedule. FCR Schedules A1 through A9 provide actual data for the period January 2015 through June 2015. They are filed monthly with the Commission, are served on all parties and are incorporated herein by reference. The FCR Schedules contained in Appendix I also provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2015 through December 2015.

The CCR Schedules contained in Appendix II provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2015 through December 2015.

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

A. Unless otherwise indicated, the actuals data are taken from the books and records of FPL. The books and records are kept in the regular course of the Company's business in accordance with generally accepted accounting principles and practices, as well as the provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. Please describe the data that FPL has used as a comparison when calculating the FCR and CCR true-ups presented in your testimony.

A. The FCR true-up calculation compares actual/estimated data consisting of actuals for January 2015 through June 2015 and revised estimates for July 2015 through December 2015 to the data reflected in the midcourse correction that was approved by Order No. PSC-15-0161-PCO-EI, issued on April 30, 2015. The CCR true-up calculation compares actual/estimated data consisting of actuals for January 2015 through June 2015 and revised estimates for July 2015 through December 2015 to the data reflected in FPL's original projections for the period January 2015 through December 2015 filed on August 22, 2014.

Q. Please explain the calculation of the interest provision that is applicable to the FCR and CCR true-ups.

A. The calculation of the interest provision follows the methodology used in calculating the interest provision for all cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount times the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the AA financial 30-day rates as published in the Federal Reserve website on the first business day of the current and the subsequent month. The average interest rate for the projected months is the actual rate published on the first business day in July 2015, which reflects the interest rate from the last business day in June 2015.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2015 actual/estimated true-up by month?

A. Yes. Appendix I, Page 1 shows the calculation of the FCR actual/estimated true-up by month for the period January 2015 through December 2015.

Q. Please explain the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts you are requesting this Commission to approve.

A. Appendix I, Page 1 shows the calculation of the FCR end-of-period net true-up and actual/estimated true-up amount. The 2015 end-of-period net true-up amount to be carried forward to the 2016 FCR factors is an under-recovery of $83,995,808 (Column 14, Line 45). This $83,995,808 under-recovery is comprised of the actual/estimated true-up under-recovery of $83,873,265 for the period January 2015 through December 2015 (Column 14, Line 39) plus associated interest of $122,543 (Column 14, Line 40). Per Order No. PSC-15-0161-PCO-EI, issued on April 30, 2015, FPL is refunding the 2014 final true-up over-recovery of $10,088,837 in its midcourse correction fuel factors for the period May 2015 through December 2015.

Q. Were these calculations made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes, they were.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and the projections in the midcourse correction for 2015?

A. Yes. Appendix I, Page 2 provides a comparison of jurisdictional revenues and costs on a dollar per MWh basis. Appendix I, Page 3 provides a variance calculation that compares the actual/estimated period data by component to the projected data by component from the midcourse correction for the May 2015 through December 2015 period (January 2015 actuals and revised estimates for

February 2015 through December 2015).

Q. Please describe the variance analysis on Page 2 of Appendix I.

A. Appendix I, Page 2, provides a comparison of Jurisdictional Total Fuel Revenues and Jurisdictional Total Fuel Costs (including Net Power Transactions) on a dollar per MWh basis. The $83,995,808 under-recovery is primarily due to an increase in fuel prices resulting in a variance of $87,939,348, partially offset by an increase in consumption resulting in a variance of $4,066,084.

Jurisdictional total fuel revenues to be collected are estimated to be $42,424,196 higher than projected and consumption is estimated to be 1,615,918 MWh higher than projected. However, revenues per MWh are estimated to be $0.08538 lower than projected. Of the $42,424,196 increase in jurisdictional fuel revenues, $51,668,316 is due to an increase in consumption, partially offset by a decrease in price (revenues collected per MWh) of $9,244,120.

Total jurisdictional fuel costs are estimated to be $126,297,461 higher than projected, jurisdictional fuel costs per MWh are estimated to be $0.72682 higher than projected, and as I stated above, consumption is estimated to be 1,615,918 MWh higher than projected. Of the $126,297,461 increase in total jurisdictional fuel costs, $78,695,229 is due to an increase in price (fuel costs incurred per MWh) and $47,602,232 is due to an increase in consumption.

The increase in jurisdictional fuel revenues due to consumption of $51,668,316 minus the increase in jurisdictional fuel costs due to consumption of $47,602,232 resulted in a total variance due to consumption of $4,066,084. The decrease in jurisdictional fuel revenues due to price of $9,244,120 minus the increase in jurisdictional fuel costs due to fuel prices of $78,695,229 resulted in a total variance due to price of $87,939,348. The variance due to price of $87,939,348 partially offset by the variance due to consumption of $4,066,084 resulted in an under-recovery of $83,873,265. When the interest amount of $122,543 associated with the 2015 actual/estimated true-up amount is added to the calculation, the total amount of the variance is $83,995,808.

Q. Please summarize the variance schedule on Page 3 of Appendix I.

A. FPL's midcourse correction filing projected Jurisdictional Total Fuel Costs and Net Power Transactions to be $3.142 billion for 2015 (Appendix I, Page 3, Column 3, Line 38). The Actual/Estimated Jurisdictional Total Fuel Costs and Net Power Transactions are now projected to be $3.268 billion for that period (actual data for January 2015 through June 2015 and revised estimates for July 2015 through December 2015) (Appendix I, Page 3, Column 2, Line 38). Therefore, Jurisdictional Total Fuel Costs and Net Power Transactions are projected to be $126.3 million, or 4.0% higher than the midcourse correction estimates (Appendix I, Page 3, Column 4, Line 38) and Jurisdictional Fuel Revenues, net of revenue taxes for 2015 are projected to be $42.4 million, or 1.2% higher than the midcourse correction estimates (Appendix I, Page 3, Column 4, Line 30).

Q. Please explain the variances in Jurisdictional Total Fuel Costs and Net Power Transactions.

A. Below are the primary reasons for the $126.3 million variance.

Fuel Cost of System Net Generation ($104.0 million increase)

Natural gas costs are currently projected to be $54.8 million (2.0%) higher than the midcourse correction estimates. Natural gas consumption in the actual/estimated period is projected to be 623,995,212 MMBtu, which is approximately 1.8% higher than the 612,959,909 MMBtu included in the midcourse correction estimates. The unit cost of natural gas in the actual/estimated period is projected to be $4.60 per MMBtu, which is 0.14% higher than the $4.59 per MMBtu included in the midcourse correction estimates. Of the $54.8 million projected increase in natural gas costs, $50.7 million is attributable to higher consumption and $4.1 million is attributable to higher costs.

Coal costs are currently projected to be $27.2 million (26.5%) higher than the midcourse correction estimates. Coal consumption in the actual/estimated period is projected to be 48,349,453 MMBtu, which is 28.9% higher than the 37,496,981 MMBtu included in the midcourse correction estimates. The unit cost of coal in the actual/estimated period is projected to be $2.69 per MMBtu, which is 1.9% lower than the $2.75 per MMBtu included in the midcourse correction estimates. Of the $27.2 million projected increase in coal costs, $29.8 million is attributable to higher consumption and $2.6 million is attributable to lower costs.

Light oil costs are currently projected to be $11.6 million (96.4%) higher than the midcourse correction estimates. Light oil burn in the actual/estimated period is projected to be 1,200,417 MMBtu, which is 101.4% higher than the 596,091 MMBtu included in the midcourse correction estimates. The unit cost of light oil in the actual/estimated period is projected to be $19.65 per MMBtu, which is 2.5% lower than the $20.15 per MMBtu included in the midcourse correction estimates. Of the $11.6 million projected increase in light oil costs, $12.2 million is attributable to higher consumption and $0.6 million is attributable to lower costs.

Heavy oil costs are currently projected to be $11.6 million (33.7%) higher than the midcourse correction estimates. Heavy oil burn in the actual/estimated period is projected to be 3,174,869 MMBtu, which is 34.2% higher than the 2,365,399 MMBtu included in the midcourse correction estimates. The unit cost of heavy oil in the actual/estimated period is projected to be $14.46 per MMBtu, which is 0.4% lower than the $14.52 per MMBtu included in the midcourse correction estimates. Of the $11.6 million projected increase in heavy oil costs, $11.8 million is attributable to higher consumption and $0.2 million is attributable to lower costs.

Nuclear generation costs are currently projected to be $1.2 million (0.6%) lower than the midcourse correction estimates. Nuclear consumption in the actual/estimated period is projected to be 297,024,722 MMBtu, which is 0.5% higher than the 295,670,659 MMBtu included in the midcourse correction estimates. The unit cost of nuclear fuel in the actual/estimated period is projected to be $0.65 per MMBtu, which is 1.1% lower than the $0.66 per MMBtu included in the midcourse correction estimates. Of the $1.2 million projected decrease in nuclear generation costs, $2.1 million is attributable to lower costs and $0.9 million is attributable to higher consumption.

Generation data by fuel type for the actual/estimated period January 2015 through December 2015 are included in Appendix I, Schedule E3.

<u>Fuel Cost of Purchased Power ($47.4 million increase)</u>

The variance for the Fuel Cost of Purchased Power is primarily attributable to higher than projected purchases and costs under the SJRPP and UPS agreements, as well as the addition of two contracts with the Solid Waste Authority ("SWA") that have been moved from Schedule E8 to Schedule E7 for the July through December 2015 time period. FPL now projects that it will purchase 429,167 MWh more than projected from the SJRPP and UPS agreements combined. In addition, FPL now projects that SJRPP and UPS purchases will average $5.67/MWh and $1.57/MWh higher, respectively, than projected. The combination of higher purchases and costs from the SJRPP and UPS agreements account for $28.5 million, or 60% of the total variance of $47.4 million. The remaining variance of just under $19 million is due to the inclusion of the SWA contracts on Schedule E7 (previously shown on Schedule E8) for the remainder of the year. Effective with the commercial operation date of the second unit at the SWA Palm Beach facility in July 2015, these contracts became firm purchased power agreements and are appropriately captured on Schedule E7 from this point forward.

<u>Energy Cost of Economy Purchases ($8.8 million increase)</u>

The variance for the Energy Cost of Economy Purchases is attributable to higher than projected economy purchases and higher than projected costs for economy purchases. FPL now projects that it will purchase 98,805 MWh more of economy energy, resulting in a variance of $2.4 million. FPL also projects that the average cost of economy purchases will be $14.85/MWh higher than projected, resulting in a variance of $6.4 million. The combination of higher purchases and higher costs results in a total variance of $8.8 million for the Energy Cost of Economy Purchases.

<u>Fuel Cost of Power Sold ($2.3 million decrease)</u>

The variance for the Fuel Cost of Power Sold is primarily attributable to lower than projected economy sales. FPL now projects that it will sell 268,054 MWh less of economy power than projected, resulting in a variance of $5.8 million. This variance is partially offset by higher than projected fuel costs attributable to economy sales. FPL now projects that its average fuel costs attributable to economy sales will be approximately $1.45/MWh higher, resulting in a variance of $3.6 million. The combination of lower economy sales and higher fuel costs on economy sales results in a total variance of approximately $2.2 million of the total variance for the Fuel Cost of Power Sold of $2.3 million. The remaining variance of $0.1 million is attributable to lower than projected fuel costs on St. Lucie Plant Reliability Exchange sales, partially offset by higher than projected St. Lucie Plant Reliability Exchange sales.

<u>Gains from Off-System Sales ($1.9 million decrease)</u>

The variance for Gains from Off-System Sales is primarily attributable to lower than projected economy sales. FPL now projects that it will sell 268,054 MWh less of economy sales than projected, resulting in a variance of $2.9 million. This variance is partially offset by higher than projected margins on economy sales. FPL now projects that the average margin on economy sales will be $0.40/MWh higher than projected, resulting in a variance of $1.0 million. The combination of lower economy sales coupled with slightly higher margins on economy sales results in a total variance for Gains from Off-System Sales of $1.9 million.

Energy Payments to Qualifying Facilities ($26.5 million decrease)

The variance for Energy Payments to Qualifying Facilities is primarily attributable to the removal of the SWA contracts from Schedule E8. As previously described, effective with the commercial operation date of the second unit at the SWA Palm Beach facility in July 2015, the two SWA contracts will now be captured on Schedule E7. The removal of these contracts from Schedule E8 resulted in a variance of $24.6 million, or almost 93% of the total variance of $26.5 million. Additionally, FPL now projects that it will utilize almost 104,000 MWh less than projected from the Indiantown Co-Gen ("ICL") facility. This decrease in purchases from ICL, when coupled with a projected average cost increase of $4.14/MWh, results in an additional variance of $2.5 million. The decrease in costs associated with the SWA and ICL contracts are partially offset by an increase in costs at the Cedar Bay facility. While FPL now projects to utilize 20,202 MWh less from the Cedar Bay facility, an average projected cost increase of $2.27/MWh yields a net variance of $0.6 million.

Variable Power Plant O&M Costs over 514,000 MWh Threshold ($0.6 million decrease)

The variance of $0.6 million is due to lower than projected economy sales.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2015 actual/estimated true-up by month?

A. Yes. Appendix II, Page 1 provides the calculation of the CCR actual/estimated true-up by month for the period January 2015 through December 2015.

Q. Please explain the calculation of the CCR 2015 end-of-period net true-up and actual/estimated true-up amounts you are requesting this Commission to approve.

A. Appendix II, Page 1 shows the calculation of the CCR end-of-period net true-up and actual/estimated true-up amounts. The 2015 end-of period true up amount to be carried forward to the 2016 CCR factors is an over-recovery of $1,458,375 (Column 14, Line 24). This $1,458,375 net over-recovery is comprised of the 2014 Final True-up under-recovery of $2,951,171 filed with the Commission on March 3, 2015 (Column 14, Line 22) and the actual/estimated true-up over-recovery of $4,404,044 for the period January 2015 through December 2015 (Column 14, Line 19) plus associated interest of $5,502 (Column 14, Line 20).

Q. Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes, it is.

Q. Have you provided a schedule showing the variances between the actual/estimated and the original projections for 2015?

A. Yes. Appendix II, Page 2 shows the actual/estimated capacity charges and applicable revenues (January 2015 through June 2015 reflects actual data and the data for July 2015 through December 2015 is based on updated estimates) compared to the original projections for the January 2015 through December 2015 period.

Q. Please explain the variances related to capacity charges.

A. As shown in Appendix II, Page 2, Column 4, Line 15, the variance related to jurisdictional capacity charges is $3.1 million, a 0.6% decrease from original projections. The primary reason for this variance is a $3.3 million or 0.6% decrease in total system capacity costs (Page 2, Column 4, Line 11).

Below are the primary reasons for the $3.3 million decrease in total system capacity costs.

<u>Payments to Non-Cogenerators ($11.0 million increase)</u>

The variance for Payments to Non-Cogenerators (UPS, SJRPP & SWA) is primarily attributable to the inclusion of costs for the SWA contracts. Effective with the commercial operation date of the second unit at the SWA Palm Beach facility in July 2015, the two SWA contracts will now be considered Non-Cogenerators. Inclusion of these contracts, from the Payments to Co-Generators category, resulted in a variance of approximately $8.2 million, or almost 75% of the total variance. Additionally, higher than projected costs associated with the

SJRPP agreement resulted in a variance of approximately $2.6 million, or 24% of the total variance. This $2.6 million variance consists of approximately $2.9 million resulting from higher than projected costs for Cumulative Capital Recovery Amount ("CCRA") payments, partially offset by slightly lower than projected costs for property taxes $0.4 million. FPL also projects slightly higher costs than originally expected for the UPS agreements. Higher costs of approximately $0.2 million are now projected due to Change In Law ("CIL") payments related to the Scherer unit.

Incremental Nuclear NRC Compliance O&M Costs ($1.0 million increase)

The variance for Incremental Nuclear NRC Compliance O&M Costs is primarily attributable to engineering costs associated with the Plant St. Lucie flooding hazard re-evaluation. These costs were originally projected as capital costs, but were reclassified as O&M.

Payments to Co-Generators ($6.1 million decrease)

The variance for Payments to Co-Generators is primarily due to the removal of costs for the SWA 40 MW unit contract. As previously described, effective with the commercial operation date of the second unit at the SWA Palm Beach facility in July 2015, the two SWA contracts will now be captured as Non-Cogenerators. Removal of this contract from the Payments to Co-Generators category resulted in a variance of approximately $6.7 million, or almost 110% of the total variance. Approximately 11%, or $0.7 million, of the net variance was attributable to higher than projected payments to Cedar Bay. A decrease in payments to SWA during the first half of the period resulted in a variance of $93,000 or approximately 1% of the total variance.

Incremental Plant Security O&M Costs ($5.6 million decrease)

The variance for Incremental Plant Security O&M costs is primarily due to scope changes resulting in lower costs than originally projected. Uncertainties related to the NERC Critical Infrastructure Protection ("CIP") Low-Impact Rating Standards led to a redeveloped NERC CIP Version 5 transition and implementation plan to include NERC CIP requirements at FPL's affected facilities.

Transmission of Electricity By Others ($1.4 million decrease)

The variance for Transmission of Electricity By Others is due to higher than projected UPS power purchases, resulting in lower than projected unutilized transmission costs. FPL projects to purchase approximately 212,524 more MWh than originally projected for 2015.

Incremental Nuclear NRC Compliance Capital Costs ($0.8 million decrease)

The variance for Incremental Nuclear NRC Compliance depreciation and return is primarily due to estimated costs associated with the Turkey Point Unit 3 and 4 Reactor Coolant Pumps being incurred later in the year than originally projected.

Transmission Revenues from Capacity Sales ($0.7 million increase)

The variance for Transmission Revenues from Capacity Sales is attributable to higher than projected economy power sales relative to FPL's original 2015

Projection Filing.

<u>Incremental Plant Security Capital Costs ($0.5 million decrease)</u>

The variance for Incremental Plant Security depreciation and return is primarily due to scope changes resulting in lower costs than originally projected. The inconsistency between NERC standard revisions and FERC communications led to a redeveloped NERC CIP version 5 transition and implementation plan. Additionally, there was a shift in work at the West County and Manatee plants due to a change in the outage schedule from spring to fall as a result of limited resources.

<u>SJRPP Suspension Accrual ($0.2 million increase)</u>

The variance for the SJRPP Suspension Accrual is due to slightly higher than projected accrual amounts when compared to original calculations. The increase is primarily due to a reduction in estimated property tax expense. The current estimate is approximately 6.8% lower than the prior year projection.

Q. What is the variance in CCR revenues?

A. In addition to the cost variances, Appendix II, Page 2, Column 4, line 16 shows that actual Capacity Cost Recovery Revenues (Net of Revenue Taxes) are projected to be $1.3 million higher than originally estimated. The $3.1 million decrease in costs (Appendix II, Page 2, Column 4, Line 15) less the $1.3 million increase in revenues results in the actual/estimated 2015 true-up over-recovery amount of $4.4 million, including interest (Appendix II, Page 2, Column 4, Lines 19 plus 20).

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. 150001-EI

SEPTEMBER 1, 2015

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- I present a revised 2015 Fuel Cost Recovery ("FCR") actual/estimated true-up amount, which has been updated to include July 2015 actual data that is incorporated into the calculation of the 2016 FCR factors.
- I present FCR factors for the period January 2016 through May 2016 and June 2016 through December 2016 that reflect the Port Everglades Next Generation Clean Energy Center ("PEEC") fuel savings in the period after the unit goes into service (projected to be June 1, 2016). I also present for informational purposes, 2016 FCR

factors based on the traditional factor calculation methodology, which spreads the fuel savings associated with PEEC over the entire calendar year.

- I present the calculation of the jurisdictional amount of FPL's portion of the 2014 incentive mechanism gains for recovery through the 2016 FCR factors.
- I present an alternative cost recovery approach with respect to FPL's wholesale firm power sales agreement with Seminole Electric Cooperative, Inc. in order to appropriately allocate costs between retail and wholesale customers.
- I present a revised 2015 Capacity Cost Recovery ("CCR") actual/estimated true-up amount, which has been updated to include July 2015 actual data that is incorporated into the calculation of the 2016 CCR factors.
- I present the CCR factors for the period January 2016 through December 2016. I also provide CCR factors for the period January 2016 through December 2016 including an adjustment to recover the non-fuel revenue requirements associated with West County Energy Center Unit 3 ("WCEC-3") for the period January 2016 through December 2016, as approved in Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013.
- I present the WCEC-3 revenue requirement calculation for the January 2016 through December 2016 period.
- Finally, I provide on pages 95-96 of Appendix II FPL's proposed

cogeneration ("COG") tariff sheets, which reflect 2016 projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten-year projection of FPL's annual generation mix and fuel prices.

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

A. Yes, I have. They are as follows:

TJK-6 (Appendix II)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 provide the calculation of FCR factors for January 2016 through May 2016, which exclude PEEC fuel savings.
- Schedule E1-A, a revised Schedule E1-B, which includes July 2015 actual data, Schedules E1-C, E1-D, Calculation of Jurisdictional Incentive Mechanism Gains – FPL Portion and H1, which pertain to the entire 2016 calendar year.
- Pages 10 through 13, which provide the 2016 Projected Energy Losses by Rate Class.
- Pages 95 and 96, which provide updated COG tariff sheets.

TJK-7 (Appendix III)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 for the period June 2016 through December 2016, which include PEEC fuel savings.

TJK-8 (Appendix IV)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 that provide the calculation of FCR factors for the period January 2016 through December 2016 based on the traditional factor calculation methodology, which spreads the PEEC fuel savings over the entire calendar year.

TJK-9 (Appendix V)

- Page 1 provides the calculation of the revised 2015 Actual/Estimated CCR True-Up amount, which reflects July 2015 actual data.
- Pages 2 through 4 provide the calculation of the 2016 CCR factors excluding the WCEC-3 non-fuel revenue requirement for January 2016 through December 2016.
- Pages 5 through 8 provide the calculation of depreciation and return on incremental power plant security and incremental Nuclear Regulatory Commission ("NRC") compliance capital investments.
- Pages 11 through 13 provide the calculation of the portion of the CCR factors that recovers the non-fuel revenue requirement associated with WCEC-3 for the period January 2016 through December 2016.
- Page 14 combines the results from pages 2 through 4 and pages 11 through 13 to provide the total 2016 CCR factors including the non-fuel revenue requirement associated with WCEC-3 for the period January 2016 through December 2016.
- Page 15 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 through the CCR Clause for the period January 2016 through December 2016.

TJK-10 (Appendix VI)

- Pages 1 and 2 provide the calculation of the WCEC-3 revenue requirement for January 2016 through December 2016.

FUEL COST RECOVERY CLAUSE

Q. Has FPL revised its 2015 FCR Actual/Estimated True-up amount that was filed on August 4, 2015 to reflect July actual data?

A. Yes. The 2015 FCR actual/estimated true-up amount has been revised to an under-recovery of $71,388,622, incorporating July 2015 actual data, plus interest. This revised 2015 FCR actual/estimated $71,388,622 under-recovery is included in the calculation of the FCR factors for the January 2016 through December 2016 period.

Q What adjustments are included in the calculation of the 2016 FCR factors shown on Schedules E1 included in Appendices II, III and IV?

A. The total net true-up to be included in the 2016 FCR factors is an under-recovery of $71,388,622. This amount, divided by the projected retail sales of 109,379,466 MWh for January 2016 through December 2016, results in an increase of 0.0653¢ per kWh before applicable revenue taxes, as shown on Line 27 of Schedule E1. The Generating Performance Incentive Factor ("GPIF") testimony of witness J. Carine Bullock, filed on March 17, 2015 and adopted by FPL witness Charles Rote, proposes a reward of $23,303,114 for the period ending December 2014. This $23,303,114 reward, divided by the projected retail sales of 109,379,466 MWh for January 2016 through December 2016, results in an increase of 0.0213¢ per kWh, as shown on Line 31 of Schedule E1.

Recovery of FPL's Portion of 2014 Incentive Mechanism Gains

Q. Is FPL including any additional adjustments in the calculation of the 2016 FCR factors shown on Schedules E1 included in Appendices II, III and IV?

A. Yes. FPL is including $12,349,600 in the calculation of its 2016 FCR factors, which represents the jurisdictional amount associated with its share of 2014 Incentive Mechanism Gains that FPL is allowed to retain per the settlement agreement approved in Order No. PSC. 13-0023-S-EI and which is being treated consistent with FPL's recovery methodology of approved GPIF amounts.

As presented and explained in the direct testimony and exhibits of FPL witness Gerry Yupp filed on March 3, 2015 in this docket, FPL's activities under the Incentive Mechanism during 2014 delivered $67,626,867 million in total gains. Of these total gains, FPL is allowed to retain $12,976,120 million (system amount). FPL will reflect recovery of one-twelfth of the approved amount, net of revenue taxes, in each month's Schedule A2 for the period January 2016 through December 2016 as a reduction to jurisdictional fuel revenues applicable to each period.

Q. How has FPL calculated the jurisdictional share of the 2014 Incentive Mechanism Gains?

A. As shown on Page 5 of Appendix II, FPL calculated an average jurisdictional separation factor of 95.10327%, which is based on actual 2014 sales. This separation factor is applied to the $12,976,120 resulting in a jurisdictional amount of $12,340,714. This amount is then adjusted for revenue taxes resulting in $12,349,600, which is the total jurisdictional amount of FPL's share of the 2014 Incentive Mechanism Gains. The $12,349,600 is included in the calculation of the average FCR factor on Line 32 of Schedule E1.

Seminole Electric Cooperative, Inc. Power Sales Agreement

Q. What is the current treatment for calculating retail jurisdictional fuel costs on separated power sales?

A. Per FPSC Order No. PSC-97-0262-FOF-EI (the "Separated Sales Order"), FPL is required to utilize the traditional jurisdictional separation approach, which provides for fuel expenses related to long-term contracts to be separated based on average system costs, unless it requests and receives Commission approval for an alternative approach.

Q. Is FPL requesting approval for an alternative approach to be applied to a separated power sale in the 2016 projection period?

A. Yes. As required under the Separated Sales Order, FPL is seeking FPSC approval to deviate from the separated sales approach in order to appropriately allocate costs between retail and wholesale customers for its sale of 200 MW of firm capacity to Seminole Electric Cooperative, Inc. ("Seminole") under a long-term wholesale firm capacity agreement (the "Agreement").

Q. Why is FPL requesting this change for the Seminole Agreement?

A. Under the terms of the Agreement, energy charges are based on a specified heat rate times the daily midpoint price in $/MMBtu for the relevant day of delivery of energy as published in Platt's Gas Daily for the Florida City Gate. This calculated amount for energy charges under the Agreement is different than the average system fuel costs that would be allocated to Seminole under the standard separated sales approach. FPL is requesting a deviation from the separated sales approach in order to bring the cost allocation more in line with the basis for FPL's energy charges under the Agreement.

Q. What is the alternative approach that FPL proposes for jurisdictional separation of sales under the Agreement?

A. FPL requests to credit all fuel revenues received under the Agreement against the total system fuel costs for the period and exclude Seminole's kWh sales from the calculation of the monthly fuel retail separation factor. Additionally, the fuel revenues received from Seminole will be reported on a separate line in the monthly A2 Schedule; in this manner it would provide clarity around the methodology used to compute the monthly fuel retail separation factor and clearly identify the revenues that lowered total system fuel costs to be recovered from retail customers.

Q. The Separated Sales Order requires that a utility demonstrate benefits to retail customers from a separated sale for which it is seeking to apply an alternative approach for jurisdictional separation of sales. Would FPL's retail customers benefit under the alternative approach that FPL proposes for sales under the Agreement?

A. Yes. Seminole was only willing to enter into the Seminole Agreement with the energy charges calculated as described above, which are not based on FPL's average system energy costs. FPL cannot justify entering into wholesale agreements for separated sales with energy charges that are not based on average system energy costs unless FPL is able to deviate from the standard jurisdictional separation approach that is based on average system energy costs. Absent the Agreement, FPL's retail customers would be responsible for more costs. Therefore, allowing FPL to apply its proposed alternative approach to sales under the Agreement will benefit retail customers and meets the test established in the Separated Sales Order.

Q. Are there other instances in which FPL has contracted to sell power to wholesale customers at a cost other than average system costs? If so, how were the revenues received under these instances treated for cost recovery purposes?

A. Yes. FPL had long-term wholesale power sales agreements with the City of Key West ("CKW") and Florida Keys Electric Cooperative ("FKEC"), which are now expired, where the basis of the costs used to bill these entities excluded all nuclear related costs. In these instances, both of which were in existence prior to the issuance of the Separated Sales Order, FPL applied a revenue crediting methodology, thus lowering the costs when determining the proper amount of costs to collect from retail customers.

Q. Is FPL's proposed alternative approach in this filing comparable to the approach that was previously applied for the CKW and FKEC contracts?

A. Yes. FPL is requesting the same treatment as was applied when the non-nuclear CKW and FKEC contracts were in effect.

Q. Is FPL planning on implementing any modifications to the way it calculates base rate revenue requirements as a result of the Seminole Agreement?

A. Yes. Currently, FPL includes Seminole in the wholesale load for the calculation of the retail separation factors and the costs allocated to wholesale include Seminole's load ratio share of average system costs, as required by the separated sales approach. If the Commission approves FPL's request to deviate from the separated sales approach for fuel costs, FPL plans to apply a revenue crediting methodology to base rates in the same manner as is being requested for the fuel costs. Specifically, FPL will implement revenue crediting for base rates as follows:

- FPL will remove Seminole's load from the calculation of all applicable retail separation factors for rate base and expenses and include retail load in the separation factor for Seminole's base revenues.
- The Seminole revenues allocated to retail will be credited against retail revenue requirements for surveillance reporting and base rate setting purposes.

If approved, revenue crediting will be implemented for both base rates and fuel costs on January 1, 2016.

Calculation of 2016 FCR Factors

Q. Please explain how FPL has calculated its proposed FCR factors for the period January 2016 through December 2016 to reflect the impact of PEEC fuel savings once that unit goes into service.

A. In Order No. PSC-13-0023-S-EI, the Commission approved FPL's recovery of annualized non-fuel revenue requirements associated with PEEC contemporaneously with the in-service date of the unit, which is projected for June 1, 2016. FPL proposes that the corresponding fuel savings associated with PEEC be reflected in fuel factors to become effective when the unit goes in-service. Implementing the fuel factors reflecting those savings concurrent with the step base rate increase better aligns costs with the fuel savings benefits. This treatment is consistent with past practice approved by the Commission at the time new units come into service during the year.

Q. What are the projected jurisdictional fuel savings associated with PEEC from June 1, 2016 through the balance of 2016?

A. As explained in the testimony of FPL witness Yupp, the projected total fuel savings for that period are $39,772,262. The jurisdictional portion of those fuel savings adjusted for losses and revenues taxes is $38,039,005. The calculation of this jurisdictional amount is shown on Page 2 of Appendix III.

Q. Has FPL calculated 2016 FCR factors reflecting PEEC fuel savings commencing with the unit's in-service date?

A. Yes. FPL has prepared two E-1 Schedules to calculate average "Step 1" fuel factors to be applied during the period before PEEC goes in service, assumed to be January 2016 through May 2016, (Page 1 of Appendix II) and separate average "Step 2" fuel factors to be applied during the period after PEEC goes in-service, assumed to be June 1, 2016 through December 2016 (Page 1 of Appendix III).

Q. Please explain this calculation.

A. FPL first calculates the "Step 1" fuel factors assuming PEEC is not operating in 2016, meaning that the total fuel savings are excluded from the calculation of the levelized fuel factor on both E-1 Schedules. This adjustment is shown on Line 2. This results in a levelized fuel factor of 2.861 cents per kWh for the period January 2016 through May 2016. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $25.43 during this period.

Next, FPL adjusts the "Step 2" fuel factors for the period June 2016 through December 2016 by crediting the jurisdictional fuel savings associated with PEEC during this period. The total jurisdictional fuel savings of $38,039,005, divided by the projected sales for June 2016 through December 2016 of 68,035,141 MWh, results in a downward adjustment of 0.0559 cents per kWh, including revenue taxes (Appendix III, Page 1, Line 33). This downward adjustment results in a lower levelized FCR factor of 2.805 cents per kWh for the period June 2016 through December 2016, which reflects a reduction in the levelized fuel factor of 0.056 cents per kWh. For FPL's residential 1,000 kWh bill, this represents a fuel charge of $24.87 for that period.

Schedule E2 provides the monthly fuel factors and also the levelized FCR factor. Schedule E-1E provides the calculation of the FCR factors by rate group for each period.

Q. Has FPL also calculated levelized FCR factors that would apply uniformly throughout calendar year 2016?

A. Yes. Although FPL requests approval of its "Step 1" and "Step 2" FCR factors for 2016, FPL has also provided fuel factors using the traditional methodology for informational purposes. Appendix IV includes Schedules El, El-E, E2, RS-1 Inverted Rate Calculation and E10, which calculate a twelve-month levelized fuel factor of 2.826¢ per kWh, based on the traditional methodology. This twelve-month levelized fuel factor spreads the PEEC fuel savings throughout the twelve months of 2016.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2015 CCR Actual/Estimated True-up amount that was filed on August 4, 2015 to reflect July 2015 actual data?

A. Yes. The 2015 CCR actual/estimated true-up amount has been revised to an over-recovery of $7,255,010 (Appendix V, Page 1, Line 19 plus Line 20), incorporating July 2015 actual data, plus interest and updated capital schedules for the depreciation and return on incremental power plant security and incremental nuclear NRC compliance capital investments. The $7,255,010 over-recovery, plus the 2014 final true-up under-recovery of $2,951,171 results in a net over-recovery of $4,303,839 (Appendix V, Page 1, Line 24). This $4,303,839 net over-recovery is included in the calculation of the CCR factors for the January 2016 through December 2016 period.

Q. Have you prepared a summary of the requested capacity payments for the projected period of January 2016 through December 2016?

A. Yes. Page 2 of Appendix V provides this summary. Total Recoverable Jurisdictional Capacity Payments for the period January 2016 through December 2016 are $362,928,439 (Line 11). This $362,928,439 is decreased by the net over-recovery for 2014 and 2015 of $4,303,839 (Line 14 plus Line 15) and increased by the Nuclear Cost Recovery Clause amount of $34,249,614 (Line 16) for which FPL has sought approval in Docket No. 150009-EI. The total jurisdictional CCR amount to be recovered in 2016, including taxes but excluding the 2016 WCEC-3 non-fuel revenue requirement is $373,817,456.

Q. When will the Commission approve FPL's Nuclear Cost Recovery amount to be included in the 2016 CCR factors?

A. The Commission is scheduled to approve the Nuclear Cost Recovery amount to be included in FPL's 2016 CCR factors at its October 20, 2015 Special Agenda Conference. Per the Order Establishing Procedure in this docket, if the Commission makes any changes to FPL's requested recovery amount of $34,249,614 on October 19, by October 30, 2015 FPL will submit to the

Commission, with copies to all parties, revised schedules showing the calculation of the 2016 CCR factors.

Calculation of CCR Factors for WCEC-3

Q. What is the projected WCEC-3 jurisdictional non-fuel revenue requirement for the January 2016 through December 2016 period?

A. The jurisdictional non-fuel revenue requirement for January 2016 through December 2016 is $145,515,209. The calculation of this amount is shown in my Exhibit TJK-10, which is Appendix VI. The $145,515,209 reflects the actual plant-in-service balance for WCEC-3 with the return on equity ("ROE") of 10.5%, as approved in the Settlement Agreement per Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013.

Q. Have you provided a calculation of 2016 CCR factors by rate class including an adjustment to recover the non-fuel revenue requirement associated with WCEC-3 for the period January 2016 through December 2016?

A. Yes. As approved in Order No. PSC-13-0023-S-EI, FPL has included in Appendix VI the 2016 non-fuel revenue requirement associated with WCEC-3 of $145,515,209. Accordingly, Exhibit TJK-9, which is Appendix V to my testimony, shows the calculation of the 2016 CCR factors including the non-fuel revenue requirement associated with WCEC-3 for the period January 2016 through December 2016.

Q. What is the total jurisdictional CCR amount to be recovered in 2016?

A. The total CCR jurisdictional amount to be recovered in 2016 is $519,332,665.

Q. Have you prepared a calculation of the allocation factors for demand and energy?

A. Yes. Page 3 of Appendix V provides this calculation. 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. What effective date is FPL requesting for the new FCR and CCR factors?

A. FPL is requesting that the FCR and CCR factors become effective with customer bills for January 2016 (cycle day 1, which will be January 4, 2016) and that they remain effective until cycle day 21 of December 2016, or until they are modified by the Commission. This will provide for 12 months of billing on the FCR and CCR factors for all customers.

<u>Proposed 2016 Residential Bill</u>

Q. What is FPL's proposed preliminary residential 1,000 kWh bill for the period beginning January, 2016?

A. Based on FPL's requests in this docket, Docket No. 150002-EI, Docket No. 150007-EI and Docket No. 150009-EI, its preliminary residential 1,000 kWh bill for January 2016 through May 2016 is $93.24. Once PEEC becomes commercially operational, which is projected to be June 1, 2016, FPL's base rate charges will increase to $57.00 and its FCR charge will decrease to $24.87. The base rate change reflects the application of a Generation Base Rate Adjustment ("GBRA") for PEEC consistent with the Stipulation and Settlement that was approved in Order No. PSC-13-0023-S-EI. Appendix VII contains the affidavit and supporting schedules of Kim Ousdahl, which present the base rate revenue requirement of $215.6 million for the first twelve months of operation for FPL's PEEC. Appendix VIII contains the affidavit of Tiffany Cohen and GBRA supporting schedules for PEEC. FPL's preliminary Residential 1,000 kWh bill for the period June 2016 through December 2016 is $94.86, which is an increase of $1.62, from its January 2016 through May 2016 bill. FPL's proposed preliminary Residential 1,000 kWh bills for 2016 are provided on Schedule E-10, which is page 7 of Exhibit TJK-7, Appendix III.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLEMENTAL TESTIMONY OF TERRY J. KEITH

DOCKET NO. 150001-EI

SEPTEMBER 21, 2015

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- I present a revised 2015 Fuel Cost Recovery ("FCR") actual/estimated true-up amount, which has been updated to include July 2015 actual data that is incorporated into the calculation of the 2016 FCR factors.
- I present FCR factors for the period January 2016 through May 2016 and June 2016 through December 2016 that reflect the Port Everglades Next Generation Clean Energy Center ("PEEC") fuel savings in the period after the unit goes into service (projected to be June 1, 2016). I also present for informational purposes, 2016 FCR

factors based on the traditional factor calculation methodology, which spreads the fuel savings associated with PEEC over the entire calendar year.

- I present the calculation of the jurisdictional amount of FPL's portion of the 2014 incentive mechanism gains for recovery through the 2016 FCR factors.
- I present a revised 2015 Capacity Cost Recovery ("CCR") actual/estimated true-up amount, which has been updated to include July 2015 actual data that is incorporated into the calculation of the 2016 CCR factors.
- I present the CCR factors for the period January 2016 through December 2016. I also provide CCR factors for the period January 2016 through December 2016 including an adjustment to recover the non-fuel revenue requirements associated with West County Energy Center Unit 3 ("WCEC-3") for the period January 2016 through December 2016, as approved in Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013.
- I present the WCEC-3 revenue requirement calculation for the January 2016 through December 2016 period.
- Finally, I provide on pages 95-96 of Appendix II FPL's proposed cogeneration ("COG") tariff sheets, which reflect 2016 projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten-year projection of FPL's annual generation mix and fuel prices.

The revised 2015 FCR actual/estimated true-up and 2016 FCR projections as well as the revised 2015 CCR actual/estimated true-up and 2016 CCR projections referenced below reflect the impact of acquiring the Cedar Bay facility and terminating the existing Cedar Bay power purchase agreement ("PPA"), consistent with the terms of the settlement agreement between FPL and the Office of Public Counsel ("OPC") that was approved in Docket No. 150075-EI by the Commission at the agenda conference held on August 27, 2015.

In addition, the revised 2016 FCR projections reflect application of the standard separated sales methodology to recovery of fuel costs associated with FPL's wholesale power sale to Seminole Electric Cooperative, rather than the alternative approach that FPL proposed in its September 1, 2015 filing in this docket. At Staff's request, FPL has agreed to defer consideration of FPL's alternative cost recovery approach to next year's FCR and CCR Clause proceedings.

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

A. Yes, I have. They are as follows:

TJK-6 (Appendix II)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 provide the calculation of FCR factors for January 2016 through May 2016, which exclude PEEC fuel savings.
- Schedule E1-A, a revised Schedule E1-B, which includes July

2015 actual data, Schedules E1-C, E1-D, Calculation of Jurisdictional Incentive Mechanism Gains – FPL Portion and H1, which pertain to the entire 2016 calendar year.

- Pages 10 through 13, which provide the 2016 Projected Energy Losses by Rate Class.
- Pages 95 and 96, which provide updated COG tariff sheets.

TJK-7 (Appendix III)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 for the period June 2016 through December 2016, which include PEEC fuel savings.

TJK-8 (Appendix IV)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 that provide the calculation of FCR factors for the period January 2016 through December 2016 based on the traditional factor calculation methodology, which spreads the PEEC fuel savings over the entire calendar year.

TJK-9 (Appendix V)

- Page 1 provides the calculation of the revised 2015 Actual/Estimated CCR True-Up amount, which reflects July 2015 actual data.
- Pages 2 through 4 provide the calculation of the 2016 CCR factors excluding the WCEC-3 non-fuel revenue requirement for January 2016 through December 2016.
- Pages 5 through 8 provide the calculation of depreciation and

return on incremental power plant security and incremental Nuclear Regulatory Commission ("NRC") compliance capital investments.

- Pages 11 through 13 provide the calculation of the portion of the CCR factors that recovers the non-fuel revenue requirement associated with WCEC-3 for the period January 2016 through December 2016.
- Page 14 combines the results from pages 2 through 4 and pages 11 through 13 to provide the total 2016 CCR factors including the non-fuel revenue requirement associated with WCEC-3 for the period January 2016 through December 2016.
- Page 15 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 through the CCR for the period January 2016 through December 2016.
- Pages 16 and 17 provide the calculation of amortization and return on the regulatory asset related to the loss of the Cedar Bay PPA and associated income tax gross up.
- Pages 18 and 19 provide the calculation of amortization and return on the regulatory liability related to the book/tax timing difference associated with the Cedar Bay plant asset.

TJK-10 (Appendix VI)

- Pages 1 and 2 provide the calculation of the WCEC-3 revenue requirement for January 2016 through December 2016.

FUEL COST RECOVERY CLAUSE

Q. Has FPL revised its 2015 FCR Actual/Estimated True-up amount that was filed on August 4, 2015 to reflect July actual data?

A. Yes. The 2015 FCR actual/estimated true-up amount has been revised to an under-recovery of $66,818,243, incorporating July 2015 actual data, plus interest. This revised 2015 FCR actual/estimated $66,818,243 under-recovery is included in the calculation of the FCR factors for the January 2016 through December 2016 period.

Additionally, FPL has revised its estimates for the September 2015 through December 2015 period to incorporate the requirements of the Cedar Bay Settlement Agreement. Revised schedules E3 through E9 are provided on pages 97 through 125 of Appendix II.

Q. What adjustments are included in the calculation of the 2016 FCR factors shown on Schedules E1 included in Appendices II, III and IV?

A. The total net true-up to be included in the 2016 FCR factors is an under-recovery of $66,818,243. This amount, divided by the projected retail sales of 109,379,466 MWh for January 2016 through December 2016, results in an increase of 0.0611 cents per kWh before applicable revenue taxes, as shown on Line 27 of Schedule E1. The Generating Performance Incentive Factor ("GPIF") testimony of witness J. Carine Bullock, filed on March 17, 2015 and adopted by FPL witness Charles R. Rote, proposes a reward of $23,303,114 for the period ending December 2014. This $23,303,114 reward, divided by the projected retail sales of 109,379,466 MWh for January 2016 through December 2016, results in an increase of 0.0213 cents per kWh, as shown on Line 31 of Schedule E1.

Recovery of FPL's Portion of 2014 Incentive Mechanism Gains

Q. Is FPL including any additional adjustments in the calculation of the 2016 FCR factors shown on Schedules E1 included in Appendices II, III and IV?

A. Yes. FPL is including $12,349,600 in the calculation of its 2016 FCR factors, which represents the jurisdictional amount associated with its share of 2014 Incentive Mechanism Gains that FPL is allowed to retain per the settlement agreement approved in Order No. PSC-13-0023-S-EI and which is being treated consistent with FPL's recovery methodology of approved GPIF amounts.

As presented and explained in the direct testimony and exhibits of FPL witness Gerry Yupp filed on March 3, 2015 in this docket, FPL's activities under the Incentive Mechanism during 2014 delivered $67,626,867 in total gains. Of these total gains, FPL is allowed to retain $12,976,120 (system amount). FPL will reflect recovery of one-twelfth of the approved amount, net of revenue taxes, in each month's Schedule A2 for the period January 2016 through December 2016 as a reduction to jurisdictional fuel revenues applicable to each period.

Q. How has FPL calculated the jurisdictional share of the 2014 Incentive Mechanism Gains?

A. As shown on Page 5 of Appendix II, FPL calculated an average jurisdictional separation factor of 95.10327%, which is based on actual 2014 sales. This separation factor is applied to the $12,976,120 resulting in a jurisdictional amount of $12,340,714. This amount is then adjusted for revenue taxes resulting in $12,349,600, which is the total jurisdictional amount of FPL's share of the 2014 Incentive Mechanism Gains. The $12,349,600 is included in the calculation of the average FCR factor on Line 32 of Schedule E1.

Calculation of 2016 FCR Factors

Q. Please explain how FPL has calculated its proposed FCR factors for the period January 2016 through December 2016 to reflect the impact of PEEC fuel savings once that unit goes into service.

A. In Order No. PSC-13-0023-S-EI, the Commission approved FPL's recovery of annualized non-fuel revenue requirements associated with PEEC contemporaneously with the in-service date of the unit, which is projected for June 1, 2016. FPL proposes that the corresponding fuel savings associated with PEEC be reflected in fuel factors to become effective when the unit goes in-service. Implementing the fuel factors reflecting those savings concurrent with the step base rate increase better aligns costs with the fuel savings benefits. This treatment is consistent with past practice approved by the Commission at the time new units come into service during the year.

Q. What are the projected jurisdictional fuel savings associated with PEEC from June 1, 2016 through the balance of 2016?

A. As explained in the testimony of FPL witness Yupp, the projected total fuel savings for that period are $43,089,540. The jurisdictional portion of those fuel savings adjusted for losses and revenue taxes is $40,912,578. The calculation of this jurisdictional amount is shown on Page 2 of Appendix III.

Q. Has FPL calculated 2016 FCR factors reflecting PEEC fuel savings commencing with the unit's in-service date?

A. Yes. FPL has prepared two E-1 Schedules to calculate average "Step 1" fuel factors to be applied during the period before PEEC goes in service, assumed to be January 2016 through May 2016, (Page 1 of Appendix II) and separate average "Step 2" fuel factors to be applied during the period after PEEC goes in-service, assumed to be June 1, 2016 through December 2016 (Page 1 of Appendix III).

Q. Please explain this calculation.

A. FPL first calculates the "Step 1" fuel factors assuming PEEC is not operating in 2016, meaning that the total fuel savings are excluded from the calculation of the levelized fuel factor on both E-1 Schedules. This adjustment is shown on Line 2. This results in a levelized fuel factor of 2.898 cents per kWh for the period January 2016 through May 2016. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $25.80 during this period.

Next, FPL adjusts the "Step 2" fuel factors for the period June 2016 through December 2016 by crediting the projected jurisdictional fuel savings associated with PEEC during this period. The total projected jurisdictional fuel savings of $40,912,578, divided by the projected sales for June 2016 through December 2016 of 68,035,141 MWh, results in a downward adjustment of 0.0601 cents per kWh, including revenue taxes (Appendix III, Page 1, Line 33). This downward adjustment results in a lower levelized FCR factor of 2.837 cents per kWh for the period June 2016 through December 2016, which reflects a reduction in the levelized fuel factor of 0.061 cents per kWh. For FPL's residential 1,000 kWh bill, this represents a fuel charge of $25.19 for that period.

Schedule E2 provides the monthly fuel factors and also the levelized FCR factor. Schedule E-1E provides the calculation of the FCR factors by rate group for each period.

Q. Has FPL also calculated levelized FCR factors that would apply uniformly throughout calendar year 2016?

A. Yes. Although FPL requests approval of its “Step 1” and “Step 2” FCR factors for 2016, FPL has also provided fuel factors using the traditional methodology for informational purposes. Appendix IV includes Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10, which calculate a twelve-month levelized fuel factor of 2.860¢ per kWh, based on the traditional methodology. This twelve-month levelized fuel factor spreads the PEEC fuel savings throughout the twelve months of 2016.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2015 CCR Actual/Estimated True-up amount that was filed on August 4, 2015 to reflect July 2015 actual data?

A. Yes. The 2015 CCR actual/estimated true-up amount has been revised to an over-recovery of $7,699,316 (Appendix V, Page 1, Line 21 plus Line 22), incorporating July 2015 actual data, plus interest and updated capital schedules for the depreciation and return on incremental power plant security and incremental nuclear NRC compliance capital investments. The $7,699,316 over-recovery, plus the 2014 final true-up under-recovery of $2,951,171 results in a net over-recovery of $4,748,145 (Appendix V, Page 1, Line 26). This $4,748,145 net over-recovery is included in the calculation of the CCR factors for the January 2016 through December 2016 period.

Q. Have you prepared a summary of the requested capacity payments for the projected period of January 2016 through December 2016?

A. Yes. Page 2 of Appendix V provides this summary. Total Recoverable Jurisdictional Capacity Payments for the period January 2016 through December 2016 are $321,148,426 (Line 15). This $321,148,426 is decreased by the net over-recovery for 2014 and 2015 of $4,748,145 (Line 16 plus Line 17) and increased by the Nuclear Cost Recovery Clause amount of $34,249,614 (Line 18) for which FPL has sought approval in Docket No. 150009-EI. The total jurisdictional CCR amount to be recovered in 2016, including taxes but excluding the 2016 WCEC-3 non-fuel revenue requirement is $350,902,363.

Q. When will the Commission approve FPL's Nuclear Cost Recovery amount to be included in the 2016 CCR factors?

A. The Commission is scheduled to approve the Nuclear Cost Recovery amount to be included in FPL's 2016 CCR factors at its October 19, 2015 Special Agenda Conference. Per the Order Establishing Procedure in this docket, if the Commission makes any changes to FPL's requested recovery amount of $34,249,614 on October 19, by October 30, 2015 FPL will submit to the Commission, with copies to all parties, revised schedules showing the calculation of the 2016 CCR factors.

<u>Calculation of CCR Factors for WCEC-3</u>

Q. What is the projected WCEC-3 jurisdictional non-fuel revenue requirement for the January 2016 through December 2016 period?

A. The jurisdictional non-fuel revenue requirement for January 2016 through December 2016 is $145,515,209. The calculation of this amount is shown in my Exhibit TJK-10, which is Appendix VI. The $145,515,209 reflects the actual plant-in-service balance for WCEC-3 with the return on equity ("ROE") of 10.5%, as approved in the Settlement Agreement per Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013.

Q. Have you provided a calculation of 2016 CCR factors by rate class including an adjustment to recover the non-fuel revenue requirement associated with WCEC-3 for the period January 2016 through December 2016?

A. Yes. As approved in Order No. PSC-13-0023-S-EI, FPL has included in Appendix VI the 2016 non-fuel revenue requirement associated with WCEC-3 of $145,515,209. Accordingly, Exhibit TJK-9, which is Appendix V to my testimony, shows the calculation of the 2016 CCR factors including the non-fuel revenue requirement associated with WCEC-3 for the period January 2016 through December 2016.

Q. What is the total jurisdictional CCR amount to be recovered in 2016?

A. The total CCR jurisdictional amount to be recovered in 2016 is $496,417,572.

Q. Have you prepared a calculation of the allocation factors for demand and energy?

A. Yes. Page 3 of Appendix V provides this calculation. 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.

Impact of Cedar Bay Transaction on FCR and CCR Factors

Q. Has FPL included in the calculation of its 2016 FCR and CCR factors any adjustments to incorporate the requirements of the Cedar Bay Transaction consistent with the settlement agreement between FPL and OPC that was approved by the Commission on August 27, 2015?

A. Yes. FPL closed on the Cedar Bay Transaction on September 18, 2015. Shortly after closing, the existing Cedar Bay PPA will be terminated and the high capacity payments that FPL is currently obligated to make to the current facility owner under the PPA will cease. The impact of ceasing those unfavorable capacity payments on the 2015 CCR actual/estimated true-up and 2016 CCR projections is a reduction of approximately $23 million. As provided in the settlement agreement, $435.5 million of the $520.5 million regulatory asset established for the Cedar Bay purchase price is reflected in the calculation of 2015 and 2016 CCR recoverable costs. Once the PPA is terminated, FPL will operate the Cedar Bay facility as its own generating asset and will recover through the FCR its fuel and fuel-related costs for the facility, rather than the energy payments that it makes to the current owner under the PPA. The impact on the 2015 FCR actual/estimated true-up and 2016 FCR projections of incurring the Cedar Bay fuel and fuel-related costs rather than continuing to pay the favorable PPA energy charges is an increase of approximately $14 million. Thus, the net impact of the Cedar Bay Transaction is a reduction of approximately $9 million in FCR and CCR costs for 2015 and 2016.

Proposed 2016 Residential Bill

Q. What is FPL proposing as the revised preliminary residential 1,000 kWh bill for the period beginning January, 2016?

A. Based on FPL's requests in this docket, Docket No. 150002-EI, Docket No. 150007-EI and Docket No. 150009-EI, its preliminary residential 1,000 kWh bill for January 2016 through May 2016 is $93.38. Once PEEC becomes commercially operational, which is projected to be June 1, 2016, FPL's base rate charges will increase to $57.00 and its FCR charge will decrease to $25.19. The base rate change reflects the application of a Generation Base Rate Adjustment ("GBRA") for PEEC consistent with the Stipulation and Settlement that was approved in Order No. PSC-13-0023-S-EI. Appendix VII contains the affidavit and supporting schedules of Kim Ousdahl, which present the base rate revenue requirement of $215.6 million for the first twelve months of operation for FPL's PEEC. Appendix VIII contains the affidavit of Tiffany Cohen and supporting GBRA schedules for PEEC. FPL's preliminary Residential 1,000 kWh bill for the period June 2016 through December 2016 is $94.95, which is an increase of $1.57, from its January 2016 through May 2016 bill. FPL's proposed preliminary Residential 1,000 kWh bills for 2016 are provided on Schedule E-10, which is page 7 of Exhibit TJK-7, Appendix III.

Q. How does the revised proposed residential bill for 1,000 kWh compare to the FPL's proposed bill in the September 1, 2015 filing?

A. The impact of the Cedar Bay Transaction has the effect of reducing the proposed residential 1,000 kWh bill by $0.09. This $0.09 reduction is made up of an increase to the FCR charge of $0.14 and a decrease to the CCR charge of $0.23.

However, FPL's supplemental filing also removes the effect of its proposed alternative approach to recovery of fuel costs associated with the Seminole wholesale power agreement, which had been included in the September 1 filing. In preparing the supplemental filing, it has come to FPL's attention that the September 1 filing understated the impact of the alternative Seminole approach by approximately $0.23. Removing the effect of the alternative Seminole approach thus increases the FCR charge by $0.23, rather than reducing it as one would expect.

Taking both of these changes into account means that the FCR charge increases by $0.37 (i.e., $0.14 for Cedar Bay + $0.23 for the alternative Seminole adjustment). The net of this $0.37 FCR increase and the $0.23 CCR decrease is an increase of $0.14 to the proposed 2016 residential 1,000 kWh bill.

Q. What effective date is FPL requesting for the new FCR and CCR factors?

A. FPL is requesting that the FCR and CCR factors become effective with customer bills for January 2016 cycle day 1 (which will be January 4, 2016) and that they remain effective until cycle day 21 of December 2016, or until they are modified by the Commission. This will provide for 12 months of billing on the FCR and CCR factors for all customers.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF DON GRISSETTE

DOCKET NO. 150001-EI

MARCH 3, 2015

Q. Please state your name and address.

A. My name is Don Grissette. 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 (FPL) as General Manager of Change Management and Organizational Development in the Nuclear Business Unit.

Q. Have you previously filed testimony in this or a predecessor docket?

A. Yes, I have.

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

A. I am responsible for the continuous improvement process for improving fleet efficiency, organizational design and effectiveness of the nuclear fleet.

Q. What is the purpose of your testimony?

A. My testimony discusses the outage extension that occurred in April 2014 at FPL's Plant St. Lucie Unit 2.

Q. Please summarize the outage extension at St. Lucie Unit 2 in April 2014.

A. In April 2014, while Unit 2 was shut down to perform a scheduled refueling outage, the following events delayed the restart of the unit:

- During reactor coolant pump start-ups, a monitor alarm indicated the presence of foreign materials in the steam generator. The foreign material was located and removed from the primary side of the 2B steam generator.
- During the inspection of the Unit 2 Steam Generator Feed Rings, it was identified that repairs would be required for the feed ring supports.
- After completing repairs to the Hydrazine pump discharge isolation valve as part of the scheduled outage work, the pump failed its post maintenance test, which required additional repair work.
- While performing local leak rate testing, a containment purge valve penetration failed to pressurize and required repair.

Q. What was the source of foreign material in the steam generator?

A. There is no definitive conclusion as to how the material entered the steam generator. FPL and Westinghouse each conducted an extensive investigation into the possible source of the foreign material. However, neither investigation could determine from inspection of the foreign material where it originated, and an exhaustive review of the records for work performed during this most recent outage did not indicate any instance where it appeared that foreign material might have been introduced into the steam generator. FPL believes that the foreign material most likely entered the steam generator as a result of refueling activities, and most likely during a previous refueling outage.

Q. What corrective actions have been initiated to address this event?

A. FPL suspended plant restart to establish the conditions necessary to retrieve the foreign material from the steam generator. Because the source of the foreign material has not been definitively determined, FPL was not in a position to take corrective actions specific to the event. In an abundance of caution, however, FPL revised the maintenance procedure related to reinstallation of the permanent reactor head. Under the revised maintenance procedure, the reactor cavity will remain in Foreign Material Exclusion Area, Level 1 (FMEA1) status, which is more restrictive, while maintenance is being performed until the permanent reactor head is in place. There are three levels of controls applied to open systems that prevent foreign material from being introduced. Level 1 is highest, with the most controls. Previously, Level 1 has applied only until the temporary reactor head was in place. Nonetheless, FPL has elected to be even more conservative in order to further reduce foreign-material risk.

Q. How many days was St. Lucie Unit 2 out of service due to this event?

A. The Unit 2 outage was extended due to the retrieval of foreign material in the steam generator by approximately 12 days.

Q. Please describe the circumstances related to the Unit 2 Steam Generator Feed Ring repairs.

A. During steam generator secondary side visual inspections, one foreign object was found on the loose part trapping screen in each of the two steam generators. These two objects were determined to be parts of small locking components (referred to as “keys”) that are part of the steam generator feed ring supports, which apparently were damaged during prior operating cycles. This event was unrelated to the foreign material found on the primary side of Steam Generator 2B.

Q. What corrective actions have been initiated to address this event?

A. FPL concluded that the feed ring support keys are susceptible to damage when there are high operational loads placed on the feed rings. Accordingly, FPL modified the feed ring supports to eliminate the keys.

FPL also took actions to limit the potential for the type of high operational loads on the supports that had caused the damage. Those loads can arise if leakage in the feed ring results in steam voids. These voids can rapidly collapse and result in high stresses. FPL replaced bolted end caps on the feed ring piping with welded caps, which eliminated the potential for leakage through the end caps. FPL will inspect the Unit 2 feed ring systems during the September 2015 refueling outage to verify that the modifications have addressed the conditions that were discovered in this event.

Q. How many days was St. Lucie Unit 2 out of service due to this event?

A. The Unit 2 outage was extended due to the Unit 2 Steam Generator Feed Ring modification by approximately 2 days.

Q. Please describe the circumstances related to the Hydrazine pump discharge isolation valve repair.

A. The Hydrazine pump discharge isolation valve repair failed its post-maintenance test. The valve was disassembled and found not to permit full valve closure.

Q. What corrective actions have been initiated to address this event?

A. The valve was reassembled and verified to be set up and stroked correctly in accordance with the Vendor Manual. FPL issued a new maintenance procedure to clarify how future solenoid valve disassembly, inspection, assembly and testing are to be performed.

Q. How many days was St. Lucie Unit 2 out of service due to this event?

A. The Unit 2 outage was extended due to the Hydrazine pump discharge isolation valve repair by approximately 3 days.

Q. Please describe the circumstances related to the containment purge valve repair.

A. While performing local leak rate testing, a penetration failed to pressurize. Further inspection found air blowing out of a valve which indicates the containment purge valve was not seating properly.

Q. What corrective actions have been initiated to address this event?

A. FPL repaired the valve so that it could seat properly. FPL did not conclude that any further corrective actions were necessary.

Q. How many days was St. Lucie Unit 2 out of service due to this event?

A. The Unit 2 outage was extended due to the continment purge valve repair by approximately 1 day.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF DON GRISSETTE

DOCKET NO. 150001-EI

SEPTEMBER 1, 2015

Q. Please state your name and address.

A. My name is Don Grissette. 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") as General Manager of Organizational Effectiveness in the Nuclear Business Unit.

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

A. I am responsible for the continuous improvement process for improving fleet efficiency, organizational design and effectiveness of the nuclear fleet.

Q. Have you previously filed testimony in this or a predecessor docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's projections of nuclear fuel costs for the thermal energy ("MMBtu") to be produced by our nuclear units. Nuclear fuel costs were input values to the GenTrader model that is used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2016 through December 2016. I am also updating plant security costs, Fukushima costs, and outage events.

<u>Nuclear Fuel Costs</u>

Q. What is the basis for FPL's projections of nuclear fuel costs?

A. FPL's nuclear fuel cost projections are developed using projected energy production at our nuclear units and current operating schedules, for the period January 2016 through December 2016.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2016 through December 2016.

A. FPL projects the nuclear units will produce 315,332,826 MMBtu of energy at a cost of $0.6518 per MMBtu, excluding spent fuel disposal costs, for the period January 2016 through December 2016. Projections by nuclear unit and by month are listed in Appendix II, on Schedule E-4, starting on page 18, which is attached as an exhibit to FPL witness Keith's testimony.

<u>Nuclear Plant Security Costs</u>

Q. What is FPL's projection of incremental security costs at FPL's nuclear power plants for the period January 2015 through December 2016?

A. FPL projects that it will incur $43.7 million in incremental nuclear power plant security costs in 2016. The costs consist of $4.1 million of capital expenditures and $39.6 million of O&M expenses.

Q. Please provide a brief description of the items included in incremental nuclear power plant security costs.

A. The projection includes the additional costs incurred in maintaining a security force as a result of implementing NRC's fitness for duty rule under Part 26, which strictly limits the number of hours that nuclear security personnel may work; additional personnel training; maintaining the physical upgrades resulting from implementing NRC's physical security rule under Part 73; and impacts of implementing NRC's rule under Part 73 for Cyber Security. It also includes Force on Force (FoF) modifications at the St. Lucie and Turkey Point nuclear sites to effectively mitigate new adversary tactics and capabilities employed by the NRC's Composite Adversary Force (CAF), as required by NRC inspection procedures.

<u>Fukushima-Related Costs</u>

Q. What is FPL's projection of Fukushima-related costs at FPL's nuclear power plants for the period January 2016 through December 2016?

A. FPL's current projection of Fukushima-related costs for 2016 is approximately $12.9 million of capital expenditures and $2.2 million of O&M expenses.

Q. Please provide a brief description of the items included in this projection of Fukushima-related costs.

A. FPL expects to pursue the following activities in 2016:

- Flooding mitigation upgrade: FPL will implement flooding mitigation upgrades for all units at St. Lucie and Turkey Point based on the flooding assessments developed in 2014 and 2015.
- Station Blackout Mitigation: FPL will implement its Station Blackout (also known as extended loss of AC power or ELAP) mitigation strategies. The implementation will include:
  - Installing in Turkey Point Unit 4 low leakage Reactor Coolant Pump (RCP) Seals in 2016. RCP seal injection is lost during a station blackout. Existing RCP seals would stop functioning following the loss of injection pressure, resulting in excessive Reactor Coolant System (RCS) leakage. New low leakage seals greatly reduce the RCS inventory loss and thus provide more robust protection against any impairment of core-cooling capacity.
  - Modifications to existing plant equipment that provide a means to tie portable equipment into existing electrical systems on Turkey Point Unit 4.

- Emergency procedure upgrades.
- Payment of NRC fees charged for NRC work-hours spent reviewing FPL's responses associated with the various regulatory orders and information requests.

Q. Is there a possibility of further NRC Fukushima-related initiatives in 2016 and beyond, in addition to those included in FPL's projection?

A. Yes. A risk exists that FPL may have to undertake additional analysis or modifications as a result of the NRC review of FPL's action to comply with the current Fukushima Orders. Also, the NRC is considering new Rules, Orders and/or Directives for Fukushima related upgrades (Tier 2 Actions). For example, the NRC could require licensees to hold training exercises for multi-unit and prolonged station blackout scenarios and re-evaluate external hazards (other than seismic and flooding). The results of the re-evaluation could require additional engineering support and significant modifications to station equipment.

In addition, the NRC is studying whether to require further long-term actions that could include a ten-year confirmation of the design basis for seismic and flooding hazards, enhanced capability to prevent/mitigate seismically induced fires and floods and installation of hardened vents for containment designs used at St. Lucie and Turkey Point.

FPL does not have enough information to estimate at this time whether these future actions will be required or what their cost would be, but the Commission should be aware that Fukushima-related costs could increase based on the issues that I have mentioned.

Q. Please describe the ongoing O&M costs resulting from the Fukushima-related modifications.

A. FPL will incur ongoing costs for its share of the support for the Regional Response Centers (a warehouse of off-site portable emergency equipment shared by the industry) and for maintainance and testing of the new beyond design basis event mitigation equipment. Additionally, FPL must conduct periodic drills to ensure the beyond design basis equipment is operating as designed.

2015 Outage Events

St. Lucie

Q. Has FPL experienced any unplanned outages at its St. Lucie plant in 2015?

A. Yes. In February 2015, Unit 2 was manually shut down after condenser chemistry action level limits were exceeded due to seawater leakage in the 2A1 Condenser Hotwell. The unit remained off line to locate the source of the in-leakage and perform secondary system chemistry cleanup.

Q. Please describe the circumstances related to the seawater leakage to the 2A1 Condenser Hotwell.

A. The leakage was the result of a leak in one of the condenser tubes located in the lower tube bundle of the 2A1 condenser. FPL will perform follow-up condenser inspections during the upcoming refueling outage to further investigate causal factors, such as the tube support design, that may have resulted in tube leakage.

Q. What interim actions have been initiated to address this event?

A. FPL plugged the condenser tube that showed evidence of leakage. Also, as a conservative measure, FPL plugged an additional 187 selected tubes (188 tubes in total) located in the same bottom center section of the lower bundles in all four of the Unit 2 waterboxes. This preventative measure was performed until additional data becomes available for analysis. Finally, FPL will perform Eddy Current Testing (ECT) on the condenser tubes to establish a signal base line and remove the suspect tubes during the next refueling outage planned in October 2015. FPL will obtain lab testing to determine the root cause of the tube leak and perform the necessary corrective actions to prevent recurrence.

Q. How many days was St. Lucie Unit 2 out of service due to this event?

A. The Unit 2 outage due to the 2A1 condenser tube leak event was approximately 4 days.

Q. Has FPL experienced any other unplanned outages at St. Lucie Unit 2 in 2015?

A. Yes. In April 2015, FPL identified a leak in the 2B2 Safety Injection Tank (SIT) discharge header piping (SI-459) located at an attachment weld of a support lug for support SI-4203-44. Unit 2 manually shut down to repair the leak, as required by Plant Technical Specifications.

Q. Please describe the circumstances related to the leak to the SIT discharge piping.

A. FPL performed an analysis on the affected section of pipe and determined the cause of the leak was vibration fatigue. The source of the vibration was the reactor coolant system. An evaluation of the pipe support design revealed that the design of the welded lugs created elevated local stress in the vibrating environment. The legacy design issue was not identified until the malfunction occurred.

Q. What actions have been initiated to address this event?

A. FPL replaced the affected piping and modified the support for line SI-459 to address the legacy design issue and prevent future problems. Additionally, FPL revised the engineering standard to include more detail related to piping supports.

Q. How many days was St. Lucie Unit 2 out of service due to this event?

A. The Unit 2 outage due to the 2B2 SIT discharge header pipe leak was approximately 10 days.

Q. Has FPL experienced any unplanned outages at St. Lucie Unit 1 in 2015?

A. Yes. Unit 1 automatically shut down on August 9, 2015 during the performance of planned Reactor Protection System (RPS) testing. The outage duration for this event was approximately 2 days. FPL is currently in the process of investigating and evaluating this recent outage.

Turkey Point

Q. Has FPL experienced any unplanned outages at its Turkey Point plant in 2015?

A. Yes. In May 2015, while Unit 4 was in power ascension from a scheduled maintenance activity, a generator differential lockout that opened the generator output breaker caused an automatic turbine trip and subsequent shut down of the unit.

Q. Please describe the circumstances related to the generator differential lockout.

A. An investigation identified an open circuit across the terminal block points associated with the secondary of the differential protection neutral side phase “A” current transformer (“CT”). Wiring was found burned and a stud in the secondary terminal was found loose. Subsequent inspection found that a lug connecting the field wiring to the CT leads had malfunctioned. The lug caused an open circuit on the CT circuit, thereby causing the generator lockout. FPL concluded the most likely cause was that the lugged connection lacked appropriate tightness.

The CTs had been replaced in 2013 during the Extended Power Uprate outage. In reviewing the Engineering Change (“EC”) and work instructions, it did not specify a required torque for these lugged connections. The tightening requirements for this type of connection were considered to be skill of craft, and therefore no torque specification was listed in the EC or work instructions.

Q. What actions have been initiated to address this event?

A. FPL implemented a temporary modification that electrically bypassed the affected CT and re-wired protective relays to alternate CT’s. FPL will review the CT connection to determine if its design can be improved to ensure adequate tightness that remains unaffected by conditions such as background vibrations. Additionally, FPL modified the maintenance procedure and electrical cable specification to specifically call out the torque requirements. Finally, FPL will implement a preventative maintenance task to inspect all of Unit 3 and 4 Main Generator CT connections.

Q. How many additional days was Turkey Point Unit 4 out of service due to this issue?

A. The Unit 4 outage due to the generator differential lockout was approximately 2 days.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF DON GRISSETTE

DOCKET NO. 150001-EI

SEPTEMBER 21, 2015

Q. Please state your name and address.

A. My name is Don Grissette. 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") as General Manager of Organizational Effectiveness in the Nuclear Business Unit.

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

A. I am responsible for the continuous improvement process for improving fleet efficiency, organizational design and effectiveness of the nuclear fleet.

Q. Have you previously filed testimony in this or a predecessor docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's projections of nuclear fuel costs for the thermal energy ("MMBtu") to be produced by our nuclear units. Nuclear fuel costs were input values to the GenTrader model that is used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2016 through December 2016. I am also updating plant security costs, Fukushima costs, and outage events.

Nuclear Fuel Costs

Q. What is the basis for FPL's projections of nuclear fuel costs?

A. FPL's nuclear fuel cost projections are developed using projected energy production at our nuclear units and current operating schedules, for the period January 2016 through December 2016.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2016 through December 2016.

A. FPL projects the nuclear units will produce 315,332,826 MMBtu of energy at a cost of $0.6518 per MMBtu, excluding spent fuel disposal costs, for the period January 2016 through December 2016. Projections by nuclear unit and by month are listed in Appendix II, on Schedule E-4, starting on page 18, which is attached as an exhibit to FPL witness Keith's testimony.

Nuclear Plant Security Costs

Q. What is FPL's projection of incremental security costs at FPL's nuclear power plants for the period January 2015 through December 2016?

A. FPL projects that it will incur $43.7 million in incremental nuclear power plant security costs in 2016. The costs consist of $4.1 million of capital expenditures and $39.6 million of O&M expenses.

Q. Please provide a brief description of the items included in incremental nuclear power plant security costs.

A. The projection includes the additional costs incurred in maintaining a security force as a result of implementing NRC's fitness for duty rule under Part 26, which strictly limits the number of hours that nuclear security personnel may work; additional personnel training; maintaining the physical upgrades resulting from implementing NRC's physical security rule under Part 73; and impacts of implementing NRC's rule under Part 73 for Cyber Security. It also includes Force on Force (FoF) modifications at the St. Lucie and Turkey Point nuclear sites to effectively mitigate new adversary tactics and capabilities employed by the NRC's Composite Adversary Force (CAF), as required by NRC inspection procedures.

Fukushima-Related Costs

Q. What is FPL's projection of Fukushima-related costs at FPL's nuclear power plants for the period January 2016 through December 2016?

A. FPL's current projection of Fukushima-related costs for 2016 is approximately $12.9 million of capital expenditures and $2.2 million of O&M expenses.

Q. Please provide a brief description of the items included in this projection of Fukushima-related costs.

A. FPL expects to pursue the following activities in 2016:

- Flooding mitigation upgrade: FPL will implement flooding mitigation upgrades for all units at St. Lucie and Turkey Point based on the flooding assessments developed in 2014 and 2015.
- Station Blackout Mitigation: FPL will implement its Station Blackout (also known as extended loss of AC power or ELAP) mitigation strategies. The implementation will include:
  - Installing in Turkey Point Unit 4 low leakage Reactor Coolant Pump (RCP) Seals in 2016. RCP seal injection is lost during a station blackout. Existing RCP seals would stop functioning following the loss of injection pressure, resulting in excessive Reactor Coolant System (RCS) leakage. New low leakage seals greatly reduce the RCS inventory loss and thus provide more robust protection against any impairment of core-cooling capacity.
  - Modifications to existing plant equipment that provide a means to tie portable equipment into existing electrical systems on Turkey Point Unit 4.

- Emergency procedure upgrades.
- Payment of NRC fees charged for NRC work-hours spent reviewing FPL’s responses associated with the various regulatory orders and information requests.

Q. Is there a possibility of further NRC Fukushima-related initiatives in 2016 and beyond, in addition to those included in FPL’s projection?

A. Yes. A risk exists that FPL may have to undertake additional analysis or modifications as a result of the NRC review of FPL’s action to comply with the current Fukushima Orders. Also, the NRC is considering new Rules, Orders and/or Directives for Fukushima related upgrades (Tier 2 Actions). For example, the NRC could require licensees to hold training exercises for multi-unit and prolonged station blackout scenarios and re-evaluate external hazards (other than seismic and flooding). The results of the re-evaluation could require additional engineering support and significant modifications to station equipment.

In addition, the NRC is studying whether to require further long-term actions that could include a ten-year confirmation of the design basis for seismic and flooding hazards, enhanced capability to prevent/mitigate seismically induced fires and floods and installation of hardened vents for containment designs used at St. Lucie and Turkey Point.

FPL does not have enough information to estimate at this time whether these future actions will be required or what their cost would be, but the Commission should be aware that Fukushima-related costs could increase based on the issues that I have mentioned.

Q. Please describe the ongoing O&M costs resulting from the Fukushima-related modifications.

A. FPL will incur ongoing costs for its share of the support for the Regional Response Centers (a warehouse of off-site portable emergency equipment shared by the industry) and for maintainance and testing of the new beyond design basis event mitigation equipment. Additionally, FPL must conduct periodic drills to ensure the beyond design basis equipment is operating as designed.

<u>2015 Outage Events</u>

St. Lucie

Q. Has FPL experienced any unplanned outages at its St. Lucie plant in 2015?

A. Yes. In February 2015, Unit 2 was manually shut down after condenser chemistry action level limits were exceeded due to seawater leakage in the 2A1 Condenser Hotwell. The unit remained off line to locate the source of the in-leakage and perform secondary system chemistry cleanup.

Q. Please describe the circumstances related to the seawater leakage to the 2A1 Condenser Hotwell.

A. The leakage was the result of a leak in one of the condenser tubes located in the lower tube bundle of the 2A1 condenser. FPL will perform follow-up condenser inspections during the upcoming refueling outage to further investigate causal factors, such as the tube support design, that may have resulted in tube leakage.

Q. What interim actions have been initiated to address this event?

A. FPL plugged the condenser tube that showed evidence of leakage. Also, as a conservative measure, FPL plugged an additional 187 selected tubes (188 tubes in total) located in the same bottom center section of the lower bundles in all four of the Unit 2 waterboxes. This preventative measure was performed until additional data becomes available for analysis. Finally, FPL will perform Eddy Current Testing (ECT) on the condenser tubes to establish a signal base line and remove the suspect tubes during the next refueling outage planned in October 2015. FPL will obtain lab testing to determine the root cause of the tube leak and perform the necessary corrective actions to prevent recurrence.

Q. How many days was St. Lucie Unit 2 out of service due to this event?

A. The Unit 2 outage due to the 2A1 condenser tube leak event was approximately 4 days.

Q. Has FPL experienced any other unplanned outages at St. Lucie Unit 2 in 2015?

A. Yes. In April 2015, FPL identified a leak in the 2B2 Safety Injection Tank (SIT) discharge header piping (SI-459) located at an attachment weld of a support lug for support SI-4203-44. Unit 2 manually shut down to repair the leak, as required by Plant Technical Specifications.

Q. Please describe the circumstances related to the leak to the SIT discharge piping.

A. FPL performed an analysis on the affected section of pipe and determined the cause of the leak was vibration fatigue. The source of the vibration was the reactor coolant system. An evaluation of the pipe support design revealed that the design of the welded lugs created elevated local stress in the vibrating environment. The legacy design issue was not identified until the malfunction occurred.

Q. What actions have been initiated to address this event?

A. FPL replaced the affected piping and modified the support for line SI-459 to address the legacy design issue and prevent future problems. Additionally, FPL revised the engineering standard to include more detail related to piping supports.

Q. How many days was St. Lucie Unit 2 out of service due to this event?

A. The Unit 2 outage due to the 2B2 SIT discharge header pipe leak was approximately 10 days.

Q. Has FPL experienced any unplanned outages at St. Lucie Unit 1 in 2015?

A. Yes. Unit 1 automatically shut down on August 9, 2015 during the performance of planned Reactor Protection System (RPS) testing. The outage duration for this event was approximately 2 days. FPL is currently in the process of investigating and evaluating this recent outage.

Turkey Point

Q. Has FPL experienced any unplanned outages at its Turkey Point plant in 2015?

A. Yes. In May 2015, while Unit 4 was in power ascension from a scheduled maintenance activity, a generator differential lockout that opened the generator output breaker caused an automatic turbine trip and subsequent shut down of the unit.

Q. Please describe the circumstances related to the generator differential lockout.

A. An investigation identified an open circuit across the terminal block points associated with the secondary of the differential protection neutral side phase “A” current transformer (“CT”). Wiring was found burned and a stud in the secondary terminal was found loose. Subsequent inspection found that a lug connecting the field wiring to the CT leads had malfunctioned. The lug caused an open circuit on the CT circuit, thereby causing the generator lockout. FPL concluded the most likely cause was that the lugged connection lacked appropriate tightness.

The CTs had been replaced in 2013 during the Extended Power Uprate outage. In reviewing the Engineering Change (“EC”) and work instructions, it did not specify a required torque for these lugged connections. The tightening requirements for this type of connection were considered to be skill of craft, and therefore no torque specification was listed in the EC or work instructions.

Q. What actions have been initiated to address this event?

A. FPL implemented a temporary modification that electrically bypassed the affected CT and re-wired protective relays to alternate CT’s. FPL will review the CT connection to determine if its design can be improved to ensure adequate tightness that remains unaffected by conditions such as background vibrations. Additionally, FPL modified the maintenance procedure and electrical cable specification to specifically call out the torque requirements. Finally, FPL will implement a preventative maintenance task to inspect all of Unit 3 and 4 Main Generator CT connections.

Q. How many additional days was Turkey Point Unit 4 out of service due to this issue?

A. The Unit 4 outage due to the generator differential lockout was approximately 2 days.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 150001-EI

SEPTEMBER 1, 2015

Q. Please state your name and business address.

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

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

A. I am employed by Florida Power & Light Company ("FPL") and I am the Business Services Manager in the Power Generation Division of FPL, where I am responsible for budgeting, forecasting, regulatory reporting and financial internal controls for FPL's fossil generating assets.

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

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony has two purposes. First, I present FPL's generating unit equivalent availability factor ("EAF") targets and average net operating heat rate ("ANOHR") targets used in determining the Generating Performance Incentive Factor ("GPIF") for the period January through December 2016. Second, I adopt the prepared testimony and exhibit of FPL witness J. Carine Bullock entitled

"Generating Performance Incentive Factor, Performance Results for January through December 2014," as filed on March 17, 2015.

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

A. Yes, I am sponsoring Exhibit CRR-1. This exhibit supports the development of the 2016 GPIF targets (EAF and ANOHR). The first page of this exhibit is an index to the contents of the exhibit. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. Please summarize the 2016 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December 2016, FPL projects a weighted system equivalent planned outage factor of 4.0% and a weighted system equivalent unplanned outage factor of 6.9%, which yield a weighted system EAF target of 89.1%. The targets for this period reflect planned refuelings for St. Lucie Unit 1 and Turkey Point Unit 4. FPL also projects a weighted system ANOHR target of 7,347 Btu/kWh for the period January through December 2016. As discussed later in my testimony, these targets represent fair and reasonable values. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

Q. Have you established individual target levels of performance for the units to be considered in establishing the GPIF for FPL?

A. Yes, I have. Exhibit CRR-1, pages 6 and 7, contains the information summarizing the targets and ranges for EAF and ANOHR for the eleven generating units that FPL proposes to be considered as GPIF units for the period January through December 2016. All of these targets have been derived utilizing the accepted methodologies adopted in the GPIF Manual.

Q. Please summarize FPL's methodology for determining equivalent availability targets.

A. The GPIF Manual requires that the EAF target for each unit be determined as the difference between 100% and the sum of the equivalent planned outage factor (EPOF) and the equivalent unplanned outage factor ("EUOF"). The EPOF for each unit is determined by the duration and magnitude of the planned outage, if any, scheduled for the projected period. The EUOF is determined by the sum of the historical average equivalent forced outage factor (EFOF) and the equivalent maintenance outage factor (EMOF). The EUOF is then adjusted to reflect recent or projected unit overhauls following the projection period.

Q. Please summarize FPL's methodology for determining ANOHR targets.

A. To develop the ANOHR targets, historic ANOHR vs. unit net output factor curves are developed for each GPIF unit. The historic data is analyzed for any unusual operating conditions and changes in equipment that affect the predicted heat rate. A regression equation is calculated and a statistical analysis of the historic ANOHR variance with respect to the best fit curve is also performed to identify unusual observations. The resulting equation is used to project ANOHR for the unit using the net output factor calculated using the service hours from the production costing simulation program, GenTrader. This projected ANOHR value is then used in the GPIF tables and in the calculations to determine the possible fuel savings or losses due to improvements or degradations in heat rate performance. This process is consistent with the GPIF Manual.

Q. How did you select the units to be considered when establishing the GPIF for FPL?

A. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80% of the estimated system net generation. The estimated net generation for each unit is taken from the GenTrader model, which forms the basis for the projected levelized fuel cost recovery factor for the period. In this case, the eleven units which FPL proposes to use for the period January through December 2016 represent the top 81.8% of the total forecasted system net generation for this period excluding the Cape Canaveral and Riviera Beach Energy Centers. These units came into service in 2013 and 2014, respectively, and were excluded from the GPIF calculation because there is insufficient historical data to include them. For the same reason, the modernized unit at Port Everglades Next Generation Clean Energy Center, which is expected to be in commercial operation in June 2016, was excluded from the GPIF calculations. Consistent with the GPIF Manual, these units will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2016 EAF and ANOHR performance targets represent reasonable and representative levels of generation availability and efficiency?

A. Yes, they do.

Q. Do you adopt as your own the testimony and exhibit of FPL witness J. Carine Bullock entitled "Generating Performance Incentive Factor, Performance Results for January through December 2014" that was filed on March 17, 2015?

A. Yes. I adopt her testimony and will sponsor her Exhibit JCB-1 .

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLEMENTAL TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 150001-EI

SEPTEMBER 21, 2015

Q. Please state your name and business address.

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

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

A. I am employed by Florida Power & Light Company ("FPL") and I am the Business Services Manager in the Power Generation Division of FPL, where I am responsible for budgeting, forecasting, regulatory reporting and financial internal controls for FPL's fossil generating assets.

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

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony has two purposes. First, I present FPL's generating unit equivalent availability factor ("EAF") targets and average net operating heat rate ("ANOHR") targets used in determining the Generating Performance Incentive Factor ("GPIF") for the period January through December 2016. Second, I adopt the prepared testimony and exhibit of FPL witness J. Carine Bullock entitled

"Generating Performance Incentive Factor, Performance Results for January through December 2014," as filed on March 17, 2015.

Q. Does your supplemental testimony incorporate into FPL's 2016 EAF and ANOHR targets the impact of acquiring the Cedar Bay facility and terminating the existing Cedar Bay power purchase agreement consistent with the terms of the settlement agreement between FPL and the Office of Public Counsel that was approved in Docket No. 150075-EI by the Commission at the agenda conference held on August 27, 2015?

A. Yes. I have incorporated the requirements of the Cedar Bay Settlement Agreement into FPL's 2016 EAF and ANOHR targets that are included with this filing.

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

A. Yes, I am sponsoring Exhibit CRR-1. This exhibit supports the development of the 2016 GPIF targets (EAF and ANOHR). The first page of this exhibit is an index to the contents of the exhibit. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. Please summarize the 2016 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December 2016, FPL projects a weighted system equivalent planned outage factor of 4.0% and a weighted system equivalent unplanned outage factor of 6.9%, which yield a weighted system EAF target of 89.1%. The targets for this period reflect planned refuelings for St. Lucie Unit 1 and Turkey Point Unit 4. FPL also projects a weighted system

ANOHR target of 7,353 Btu/kWh for the period January through December 2016. As discussed later in my testimony, these targets represent fair and reasonable values. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

Q. Have you established individual target levels of performance for the units to be considered in establishing the GPIF for FPL?

A. Yes, I have. Exhibit CRR-1, pages 6 and 7, contains the information summarizing the targets and ranges for EAF and ANOHR for the eleven generating units that FPL proposes to be considered as GPIF units for the period January through December 2016. All of these targets have been derived utilizing the accepted methodologies adopted in the GPIF Manual.

Q. Please summarize FPL's methodology for determining equivalent availability targets.

A. The GPIF Manual requires that the EAF target for each unit be determined as the difference between 100% and the sum of the equivalent planned outage factor (EPOF) and the equivalent unplanned outage factor ("EUOF"). The EPOF for each unit is determined by the duration and magnitude of the planned outage, if any, scheduled for the projected period. The EUOF is determined by the sum of the historical average equivalent forced outage factor (EFOF) and the equivalent maintenance outage factor (EMOF). The EUOF is then adjusted to reflect recent or projected unit overhauls following the projection period.

Q. Please summarize FPL's methodology for determining ANOHR targets.

A. To develop the ANOHR targets, historic ANOHR vs. unit net output factor curves are developed for each GPIF unit. The historic data is analyzed for any unusual operating conditions and changes in equipment that affect the predicted heat rate. A regression equation is calculated and a statistical analysis of the historic ANOHR variance with respect to the best fit curve is also performed to identify unusual observations. The resulting equation is used to project ANOHR for the unit using the net output factor calculated using the service hours from the production costing simulation program, GenTrader. This projected ANOHR value is then used in the GPIF tables and in the calculations to determine the possible fuel savings or losses due to improvements or degradations in heat rate performance. This process is consistent with the GPIF Manual.

Q. How did you select the units to be considered when establishing the GPIF for FPL?

A. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80% of the estimated system net generation. The estimated net generation for each unit is taken from the GenTrader model, which forms the basis for the projected levelized fuel cost recovery factor for the period. In this case, the eleven units which FPL proposes to use for the period January through December 2016 represent the top 81.5% of the total forecasted system net generation for this period excluding the Cape Canaveral and Riviera Beach Energy Centers. These units came into service in 2013 and 2014, respectively, and were excluded from the GPIF calculation because there is insufficient historical data to include them. For the same reason, the modernized unit at Port Everglades Next Generation

Clean Energy Center, which is expected to be in commercial operation in June 2016, was excluded from the GPIF calculations. Consistent with the GPIF Manual, these units will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2016 EAF and ANOHR performance targets represent reasonable and representative levels of generation availability and efficiency?

A. Yes, they do.

Q. Do you adopt as your own the testimony and exhibit of FPL witness J. Carine Bullock entitled "Generating Performance Incentive Factor, Performance Results for January through December 2014" that was filed on March 17, 2015?

A. Yes. I adopt her testimony and will sponsor her Exhibit JCB-1 .

Q. Does this conclude your testimony?

A. Yes, it does.

DUKE ENERGY FLORIDA

DOCKET NO. 150001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January through December, 2014

DIRECT TESTIMONY OF
Christopher A. Menendez

March 3, 2015

Q. Please state your name and business address.

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

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

A. I am employed by Duke Energy Business Services LLC as Rates and Regulatory Strategy Manager.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for Duke Energy Florida, Inc. ("DEF" or the "Company"). These responsibilities include completion of regulatory financial reports and analysis of state, federal, and local regulations and their impacts on DEF.

Q. Please describe your educational background and professional experience.

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide DEF's Fuel Adjustment Clause final true-up amount for the period of January 2014 through December 2014, and DEF's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared and attached to my true-up testimony as Exhibit No. __(CAM-1T), a Fuel Adjustment Clause true-up calculation and related schedules; Exhibit No. __(CAM-2T), a Capacity Cost Recovery Clause true-up calculation and related schedules; Exhibit No. __(CAM-3T), Schedules A1 through A3, A6, and A12 for December 2014, year-to-date; and Exhibit No. __(CAM-4T), a schedule outlining the 2014 capital structure and cost rates applied to capital projects. Exhibit No. __(CAM-4T) is included for informational purposes only, as DEF's 2014 Actual True-Up Filing does not include a capital return component. Schedules A1 through A9, and A12 for the year ended December 31, 2014, were previously filed with the Commission on January 20, 2015. Revised Schedule A1 for the year ended December 31, 2014, was filed with the Commission on January 29, 2015; Revised Schedules A3, A4 and A5 for the year ended December 31, 2014 were filed with the Commission on February 3, 2015.

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

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

Q. Would you please summarize your testimony?

A. Per Order No. PSC-14-0701-FOF-EI, the projected 2014 fuel adjustment true-up amount was an under-recovery of $73.7 million. The actual under-recovery for 2014 was $62.1 million resulting in a final fuel adjustment true-up over-recovery amount of $11.6 million. Exhibit No. __(CAM-1T).

The projected 2014 capacity cost recovery true-up amount was an under-recovery of $17.0 million. The actual amount for 2014 was an under-recovery of $31.0 million resulting in a final capacity true-up under-recovery amount of $14.0 million. Exhibit No. __(CAM-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2014 for fuel cost recovery?

A. The actual ending balance as of December 31, 2014 for true-up purposes is an under-recovery of $62,067,235.

Q. How does this amount compare to DEF's estimated 2014 ending balance included in the Company's estimated/actual true-up filing?

A. The actual true-up amount attributable to the January - December 2014 period is an under-recovery of $62,067,235, which is $11,604,966 lower than the re-projected year end under-recovery balance of $73,672,203.

Q. How was the final true-up ending balance determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the period-ending jurisdictional under-recovery of $62,067,235 shown on your Exhibit No. __(CAM-1T)?

A. The factors contributing to the under-recovery are summarized on Exhibit No. __(CAM-1T), sheet 1 of 7. Net jurisdictional fuel revenues were favorable to the forecast by $97.2 million, while jurisdictional fuel and purchased power expense increased $186.4 million, resulting in a difference in jurisdictional fuel revenue and expense of $89.3 million. Both the $97.2 million increase in jurisdictional fuel revenues and $186.4 million increase in jurisdictional fuel and purchased power expense are primarily attributable to the 2013 Revised and Restated Stipulation and Settlement Agreement (RRSSA) refund of $129 million set forth in RRSSA paragraph 6.a. The $129 million refund is accounted for as an increase to retail revenue in actuals, resulting in the revenue variance, but is treated as a reduction to fuel and purchased power expense in the 2014 Projection filing. This was the primary contributor to the fuel and purchased power variance noted above. The RRSSA refunds and adjustments are discussed more fully below. The $62.1 million under-recovery also includes the deferral of $27.2 million of 2013 over-recovery approved in Order No. PSC-14-0701-FOF-EI. The net result of the difference in jurisdictional fuel revenues and expenses of $89.3 million, minus the 2013 deferral of $27.2 million and plus the 2014 interest provision calculated on the deferred balance throughout the year, is an under-recovery of $62.1 million as of December 31, 2014.

Q. Please explain the components contributing to the $11.6 million variance between the actual under-recovery of $62.1 million and the approved, estimated/actual under-recovery of $73.7 million.

A. The major factor contributing to the $11.6 million variance is a $8.3 million decrease in system fuel and net power costs.

Q. Please explain the components shown on Exhibit No. __(CAM-1T), sheet 6 of 7, which helps to explain the $194.2 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

A. Exhibit No. __(CAM-1T), sheet 6 of 7 is an analysis of the system dollar variance for each energy source in terms of three interrelated components; (1) changes in the amount (MWH's) of energy required; (2) changes in the heat rate of generated energy (BTU's per KWH); and (3) changes in the unit price of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per KWH). The $194.2 million unfavorable system variance is mainly attributable to higher than projected fuel pricing, partially offset by lower than expected purchased power transactions and the $129 million RRSSA refund, which was treated as a reduction to fuel expense for rate-making purposes in DEF's Projection filing, but was treated as an adjustment to revenue in actuals.

Q. Does this period ending true-up balance include any noteworthy adjustments to fuel expense?

A. Yes. Noteworthy adjustments are shown on Exhibit No. __(CAM-3T) in the footnote to line 6b on page 1 of 2, Schedule A2. Included in the footnote to line 6b on page 1 of 2, Schedule A2, is a replacement power credit for the Bartow CC outage of $12.9 million (system grossed up from retail).

Q. Did the Company make an adjustment for changes in coal inventory based on an Aerial Survey?

A. Yes, DEF included a favorable adjustment of $0.2 million to coal inventory, which is attributable to the semi-annual aerial surveys conducted on May 5, 2014 and October 16, 2014 in accordance with Order No. PSC-97-0359-FOF-EI, issued in Docket No. 970001-EI. This adjustment represents 0.05% of the total coal consumed at the Crystal River facility in 2014.

Q. On April 21, 2014, a fire occurred at the Bartow Combined Cycle plant resulting in an outage. Did DEF incur any replacement power costs as a result of this outage?

A. Yes, DEF incurred retail replacement power costs of approximately $12.7 million ($12.9 million system). In June 2014, DEF chose to reduce retail fuel expense by $12.7 million thereby removing the impact of the replacement power to retail customers. This adjustment is included in Exhibit No.___ (CAM-1T, Sheet 2 of 7, line A5, column June).

Q. Were there any impacts to the 2014 True-up filing associated with the 2013 Revised and Restated Stipulation and Settlement Agreement (RRSSA)?

A. Yes. Paragraphs 6.a, 7.a, 7.c, and 7.d all impact the 2014 true-up. Paragraph 6.a requires DEF to refund to retail customers the remaining 50% of $258 million, or $129 million, in 2014 through the Fuel Clause. Paragraph 6.a also requires DEF to refund to Residential and General Service Non-Demand customers $10 million in 2014 through the Fuel Clause, allocated 94% to Residential and 6% to General Service Non-Demand. Paragraph 7.a allows DEF to increase fuel rates by $1.00/mWh, or 0.10 ₵/kWh, for the accelerated recovery of the carrying charges associated with the CR3 Regulatory Asset and requires that the increases be added to the fuel factor at secondary metering consistent with the normal fuel projection process. Paragraph 7.c addresses how DEF will credit the final NEIL reimbursement through the Fuel Adjustment Clause. Paragraph 7.d relates to recovery of previously deferred amounts associated with estimated NEIL recoveries. These impacts are addressed further in the testimony below.

Q. Have you included these impacts in your calculation of the true-up balance?

A. Yes.

Q. Please describe where the impact of paragraph 6.a is included in your schedules and how this is included in the final true-up amount?

A. Exhibit No.___ (CAM-1T) (Sheets 2 and 3 of 7) shows the refund of $129 million on line C.1a allocated evenly over the 12 month period. This amount is included in the 2014 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

The 2014 Projection Filing, approved in Commission Order PSC-13-0665-FOF-EI, established the refund of the $10 million through a reduction in 2014 fuel rates for Residential and General Service, Non-Demand customers. The rate reduction is inherently reflected in the Jurisdictional Fuel Revenues reported in Exhibit No.___ (CAM-1T) (Sheets 2 and 3 of 7) on line C1. The refund of $10 million is shown on line C.1c. This amount is included in the 2014 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impact of paragraph 7.a is included in your schedules and how this is included in the final true-up amount?

A. Exhibit No.___ (CAM-1T) (Sheets 2 and 3 of 7) shows the fuel adjustment to revenue of $37 million on line C.1b. This amount is removed from the 2014 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impacts of paragraphs 7.c and 7.d are incorporated into your schedules and how these are included in the final true-up amount?

A. The $163 million is simply the net difference between the adjustments required by the two paragraphs. The $163 million is included in the $33 million true-up, which is reflected in Exhibit No.___ (CAM-1T) (Sheets 2 and 3 of 7), line C.2. This amount is included in the 2014 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Did DEF exceed the economy sales threshold in 2014?

A. Yes. DEF did exceed the gain on economy sales threshold of $0.3 million in 2014. As reported on Schedule A1, Line 15a, the gain for the year-to-date period through December 2014 was $4.5 million. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gain in excess of the three-year rolling average. For 2014, that amount is $0.8 million.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November, 2015 hearings been updated to incorporate actual data for all of year 2014?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2012 through 2014, as follows:

Year	Actual Gain
2012	$298,813
2013	$427,107
2014	$4,493,609
Three-Year Average	$1,739,843

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2014 for capacity cost recovery?

A. The actual ending balance as of December 31, 2014 for true-up purposes is an under-recovery of $30,953,686.

Q. How does this amount compare to the estimated 2014 ending balance included in the Company's estimated/actual true-up filing?

A. When the estimated 2014 under-recovery of $16,991,240 is compared to the $30,953,686 actual under-recovery, the final capacity true-up for the twelve month period ended December 2014 is an under-recovery of $13,962,446.

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

A. Yes. The calculation of the final net true-up amount follows the procedures established by the Commission in Order No. PSC-96-1172-FOF-EI. The true-up amount was determined in the manner set forth on the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the actual period-end capacity under-recovery of $31.0 million?

A. Exhibit No. __(CAM-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $31.0 million under-recovery is due primarily to the higher than projected capacity expenses, lower than projected capacity revenues, and a higher than projected actual under-recovery in 2013.

OTHER MATTERS

Q: Have you provided Schedule A12 showing the actual monthly capacity payments by contract consistent with the Staff Workshop in 2005?

A: Yes. A confidential version of Schedule A12 is included in Exhibit No. __(CAM-3T).

Q. Does this conclude your direct true-up testimony?

A. Yes.

DUKE ENERGY FLORIDA

DOCKET NO. 150001-EI

Fuel and Capacity Cost Recovery
Estimated/Actual True-Up Amounts
January through December 2015

DIRECT TESTIMONY OF
Christopher A. Menendez

August 4, 2015

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 150001-EI?

A. Yes, I provided direct testimony on March 3, 2015.

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

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission approval, Duke Energy Florida's (DEF or the Company) estimated/actual fuel and capacity cost recovery true-up amounts for the period of January through December 2015.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__ (CAM-2), which is attached to my prepared testimony, consisting of two parts. Part 1 consists of Schedules E1-B through E9, which include the calculation of the 2015 estimated/actual fuel and purchased power true-up balance and a schedule to support the capital structure components and cost rates relied upon to calculate the return requirements on all capital projects recovered through the fuel clause as required per Order No. PSC-15-0001-PCO-EI. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2015 estimated/actual capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2015 and estimated data from July through December 2015.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2015 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is an over-recovery of $78,731,031. The calculation begins with the actual under-recovered balance of $30,487,175 taken from Schedule A2, page 2 of 2, line 13, for the month of June 2015. This balance plus the estimated July through December 2015 monthly true-up calculations comprise the estimated

$78,731,031 over-recovered balance at year-end. The projected December 2015 true-up balance includes interest which is estimated from July through December 2015 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.8% per month.

Q. How does the current fuel price forecast for July through December 2015 compare with the same period forecast used in the Company's 2015 projection filing approved in Order No. PSC-14-0701-FOF-EI?

A. Natural gas costs decreased $0.47/mmbtu (9%), coal costs increased $0.17/mmbtu (5%), and light oil decreased $5.55 /mmbtu (26%).

Q. Have you made any adjustments to your estimated fuel costs for the period July through December 2015?

A. Yes, we made one adjustment totaling a net reduction of $92,851. We made an adjustment to reduce fuel costs by $92,203 (grossed up to $92,851 from retail to system) for the amortization of interest on the refund pursuant to the Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI. This adjustment is included on Schedule E1-B (sheet 2), line A5, from July – December 2015.

Q. Were there any impacts to the 2015 Estimated/Actual filing associated with the 2013 Revised and Restated Stipulation and Settlement Agreement (RRSSA)?

A. Yes. Paragraphs 6.a, 6.b, and 7.a all impact the 2015 Estimated/Actual true-up balance. Paragraph 6.a requires DEF to refund to Residential and General Service Non-Demand customers $10 million in 2015 through the Fuel Clause, allocated 94% to Residential and 6% to General Service Non-Demand. Paragraph 6.b requires DEF to refund to retail ratepayers $40 million in 2015 through the Fuel Clause. Paragraph 7.a allows DEF to increase fuel rates by $1.00/mWh, or 0.10 ₵/kWh, for the accelerated recovery of the carrying charges associated with the CR3 Regulatory Asset and requires that the increases be added to the fuel factor at secondary metering consistent with the normal fuel projection process.

Q. Have you included these impacts in your calculation of the 2015 Estimated/Actual true-up balance?

A. Yes.

Q. Please describe where the impact of paragraph 6.a is included in your schedules and how this is included in the Estimated/Actual true-up amount?

A. The 2015 Projection Filing, approved in Commission Order No. PSC-14-0701-FOF-EI, established the refund of the $10 million through a reduction in 2015 fuel rates for Residential and General Service, Non-

Demand ratepayers. The rate reduction is inherently reflected in the Jurisdictional Fuel Revenues reported in Exhibit CAM-2, Part 1, Schedule E1-B (Sheets 1 & 2) on line C.1. The refund of $10 million is shown on line C.1c. This amount is included in the 2015 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impact of paragraph 6.b is included in your schedules and how this is included in the Estimated/Actual true-up amount?

A. Exhibit CAM-2, Part 1, Schedule E1-B (Sheets 1 & 2) show the refund of $40 million on line C.1a allocated evenly over the 12 month period. This amount is included in the 2015 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impact of paragraph 7.a is included in your schedules and how this is included in the Estimated/Actual true-up amount?

A. Exhibit CAM-2, Part 1, Schedule E1-B (Sheets 1 & 2) show the fuel adjustment to revenue of $38 million on line C.1b. This amount is removed from the 2015 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Does DEF expect to exceed the three-year rolling average gain on non-separated power sales in 2015?

A. Yes, DEF estimates the total gain on non-separated sales during 2015 will be $3,193,288, which exceeds the three-year rolling average of $1,739,843 by $1,453,445. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gains in excess of the three-year rolling average. For 2015, this is estimated to be $290,689.

Q. On July 7, 2014, a fire occurred at the Hines Combined Cycle plant resulting in an outage. Has DEF included the replacement power costs resulting from this outage into the 2015 Estimated/Actual True-Up filing?

A. Yes, DEF incurred retail replacement power costs of approximately $18.6 million ($18.8 million system). DEF has included the Hines 2 retail replacement power costs in the 2015 Estimated/Actual True-Up balance.

Q. How did DEF calculate the replacement power costs resulting from the Hines 2 Outage?

A. To calculate the replacement power cost assuming Hines 2 had not experienced the extended outage, DEF ran a production cost simulation model for each day beginning July 7, 2014 through June 19, 2015; this process is consistent with DEF's prior replacement power calculations. DEF ran this model for each day applying the actual load conditions and fuel costs, which produced the total system cost assuming Hines 2 availability. DEF then compared the resulting "with Hines 2" system cost to the system cost calculated based on actual unit loadings (i.e., without Hines 2). The difference between the "with Hines 2" cost and the "without Hines 2" cost represents the system replacement power costs. The retail portion was calculated by applying the applicable retail jurisdictional factor to each respective month.

CAPACITY COST RECOVERY

Q. What is the amount of DEF's 2015 estimated capacity true-up balance and how was it developed?

A. DEF's estimated capacity true-up balance is an under-recovery of $38,643,256. The estimated true-up calculation begins with the actual under-recovered balance of $53,224,971 for the month of June 2015. This balance plus the estimated July through December 2015 monthly true-up calculations comprise the estimated $38,643,256 under-recovered balance at year-end. The projected December 2015 true-up balance includes interest which is estimated from July through December 2015 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.8% per month.

Q. What are the primary drivers of the estimated year-end 2015 capacity under-recovery?

A. The $38,643,256 under-recovery is primarily attributable to $17,081,789 of 2015 Osprey capacity expense, which was not included in DEF's 2015 Projection Filing because the Osprey Tolling Agreement was signed after DEF's 2015 Projection Filing had been developed and filed, the

2014 final true-up under-recovery of $13,962,445, and other higher projected retail jurisdictional capacity costs of $5,535,621.

Q. Has DEF included the nuclear cost recovery amounts approved in Order No. PSC 14-0701-FOF-EI and Order No. PSC-15-0176-TRF-EI?

A. Yes, DEF has included $99,643,103 of 2015 recoverable expenses associated with the Levy and CR-3 Uprate projects.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA

DOCKET NO. 150001-EI

Fuel and Capacity Cost Recovery Factors
January through December 2016

DIRECT TESTIMONY OF
Christopher A. Menendez

September 1, 2015

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 150001-EI?

A. Yes, I provided direct testimony on March 3, 2015 and August 4, 2015.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the fuel and capacity cost recovery factors of Duke Energy Florida, LLC (DEF or the Company) for the period of January through December 2016.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__(CAM-3), consisting of Parts 1, 2 and 3. Part 1 contains DEF's forecast assumptions on fuel costs. Part 2 contains fuel cost recovery (FCR) schedules E1 through E10, H1 and the calculation of the inverted residential fuel rate. I have not included the schedule that supports the rate of return applied to capital projects recovered through the fuel clause pursuant to Order No. PSC-15-0001-PCO-EI, as there are no capital projects for which DEF is requesting recovery in this docket. Part 3 contains capacity cost recovery (CCR) schedules.

FUEL COST RECOVERY CLAUSE

Q. Please describe the fuel cost factors calculated by the Company for the projection period.

A. Schedule E1 shows the calculation of the Company's jurisdictional fuel cost factor of 3.677 ¢/kWh. This factor consists of a fuel cost for the projection period of 3.9048 ¢/kWh (adjusted for jurisdictional losses), a GPIF penalty of (0.0227) ¢/kWh, and an estimated prior period over-recovery true-up of (0.2076) ¢/kWh. Utilizing this factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for service taken at secondary, primary, and transmission metering voltage levels. To perform this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales, respectively (forecasted at meter level). This is consistent with the methodology used in the development of the capacity cost recovery factors.

Schedule E1-D, lines 23-24 show the Company's proposed tiered rates of 3.353 ¢/kWh for the first 1,000 kWh and 4.353 ¢/kWh above 1,000 kWh. These rates are developed in the "Calculation of Inverted Residential Fuel Rates" schedule in Part 2.

Schedule E1-E develops the Time of Use (TOU) multipliers of 1.347 On-peak and 0.841 Off-peak. The multipliers are then applied to the levelized fuel cost factors for each metering voltage level which results in the final TOU fuel factors to be applied to customer bills during the projection period.

Q. What is the amount of the 2015 net true-up that DEF has included in the fuel cost recovery factor for 2015?

A. DEF has included a projected over-recovery of $78,731,032. This amount includes a projected actual/estimated over-recovery for 2015 of $67,126,064 net of the final 2014 true-up over-recovery of $11,604,968 as included in my Direct Testimony filed on March 3, 2015.

Q. What is the change in the levelized residential fuel factor for the projection period from the fuel factor currently in effect?

A. The projected levelized residential fuel factor for 2016 of 3.634 ¢/kWh is a decrease of 0.964 ¢/kWh or 21% from the 2015 projected levelized residential fuel factor of 4.598 ¢/kWh.

Q. Were there any impacts to the 2016 Projection filing associated with the 2013 RRSSA?

A. Yes. RRSSA paragraphs 6.a and 6.b impact the 2016 Projection filing. Paragraph 6.a requires DEF to refund to Residential and General Service Non-Demand customers $10 million in 2016 through the Fuel Clause, allocated 94% to Residential and 6% to General Service Non-Demand. Paragraph 6.b requires DEF to refund to retail ratepayers $60 million in 2016 through the Fuel Clause.

Q. Have you included these impacts in your calculation of 2016 fuel rates?

A. Yes.

Q. Please describe where the impact of paragraph 6.a is included in your schedules.

A. The $10 million refund in 2016 is allocated 94%, or $9.4 million, to the Residential Service rate schedules RS-1, RST-1, RSL-1, RSL-2 and RSS-1. The remaining 6%, or $0.6 million, is allocated to the General Service Non-Demand rate schedules GS-1, GST-1 and GS-2.

The levelized fuel cost factor, prior to the application of this refund is 3.682 ¢/kWh (Schedule E1-D, line 8). To calculate the levelized fuel cost factor for residential service, the above rate is reduced by 0.048 ¢/kWh. The adjustment reflects the rate impact of the $9.4 million refund plus the interest amortization (Schedule E1-D, lines 11-14). The resulting levelized fuel cost factor for residential service is 3.634 ¢/kWh (Schedule E1-D line 15). A similar methodology was used in the calculation of the General Service Non-Demand rate schedules (Schedule E1-D, lines 16-20).

Q. Please describe where the impact of paragraph 6.b is included in your schedules.

A. The impact of paragraph 6.b can be seen in Exhibit CAM-3, Part 2, Schedule E1 line 4. This line shows Adjustments to Fuel Cost for the period of $60.7 million. This is a system amount and includes other adjustments as well as the RRSSA refund. A breakout of this amount can be seen on Schedule RRSSA of Exhibit CAM-3, Part 2. Lines 1-3 show the breakout at the system level, while lines 6-8 show these numbers on a retail basis. Line 6 shows the total retail refund of $60 million. The adjustment to fuel cost on line 4 of Schedule E1 is included in the total cost of generated power on line 5. This amount flows into the total amount to be recovered on line 28. The amount from line 28 on Schedule E1 equals the total amount to be recovered on line 4 of Schedule E1-D. The amount on line 4 of Schedule E1-D, which includes the $60 million refund, is used to develop the fuel rates for 2016.

Q. Has DEF included the fuel rate adjustment of $1.50/mWh, as set forth in paragraph 7.a of the RRSSA, in the calculation of the 2016 fuel factors?

A. No. Consistent with DEF's petition in Docket No. 150148-EI (now consolidated into Docket No. 150171-EI), DEF has removed this adjustment from the calculation of the 2016 fuel factors. DEF has removed the fuel adjustment calculations from the 2016 Schedules included in Exhibit CAM-3, Part 2.

Q. Please explain the decrease in the 2016 fuel factor compared with the 2015 fuel factor.

A. The primary drivers of the decrease in the 2016 fuel factor are the difference in prior period true-up amount, lower projected fuel prices in 2016, removal of the RRSSA paragraph 7.a fuel adjustment and an increase in RRSSA refunds per paragraph 6.b. The 2015 fuel factor included a $74 million under-recovery, whereas the 2016 fuel factor includes a $79 million over-recovery; this results in a net change of approximately $153 million or 0.402 ¢/kWh. The projected fuel prices in 2016 are approximately $138 million, or 0.364 ¢/kWh, lower than 2015, primarily driven by a reduction in the cost of natural gas. As stated above, DEF has removed the RRSSA 7.a fuel adjustment in 2016, resulting in a 0.100 ¢/kWh reduction. Finally pursuant to RRSSA paragraph 6.b, DEF will refund $60 million to retail customers in 2016, as compared to a $40 million refund in 2015, driving a 0.053 ¢/kWh reduction.

Q. Have you made any adjustments to your estimated fuel costs for the period January through December 2015?

A. Yes, on Schedule E1, line 4, we made two adjustments totaling a net reduction of $60,716,217. First we made an adjustment to refund $60,000,000 (grossed up to $60,591,323 from retail to system) pursuant to RRSSA paragraph 6.b. We also made an adjustment to reduce fuel costs by $123,614 (grossed up to $124,894 from retail to system) for the amortization of interest on the refunds pursuant to the RRSSA.

Q. Is DEF proposing to continue the tiered rate structure for residential customers?

A. Yes. DEF is proposing to continue use of the inverted rate design for residential fuel factors to encourage energy efficiency and conservation. Specifically, the Company proposes to continue a two-tiered fuel charge whereby the charge for a customer's monthly usage in excess of 1,000 kWh (second tier) is priced one cent per kWh higher than the charge for the customer's usage up to 1,000 kWh (first tier). The 1,000 kWh price change breakpoint is reasonable in that approximately 72% of all residential energy is consumed in the first tier and 28% of all energy is consumed in the second tier. The Company believes the one cent higher per unit price, targeted at the second tier of the residential class' energy consumption, will promote energy efficiency and conservation. This inverted rate design was incorporated in the Company's base rates approved in Order No. PSC-02-0655-AS-EI.

Q. How was the inverted fuel rate calculated?

A. I have included a page in Part 2 of my exhibit that shows the calculation of the fuel cost factors for the two tiers of the residential rate. The two factors are calculated on a revenue neutral basis so that the Company will recover the same fuel costs as it would under the traditional levelized approach. The two-tiered factors are determined by first calculating the amount of revenues that would be generated by the overall levelized residential factor of 3.634 ¢/kWh shown on Schedule E1-D. The two factors are then calculated by allocating the total revenues to the two tiers for residential customers based on the total annual energy usage for each tier.

Q. How do DEF's projected gains on non-separated wholesale energy sales for 2016 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2016 is estimated to be $915,242 which is below the benchmark of $2,704,668. 100% of gains below the benchmark and 80% of gains above the benchmark will be distributed to customers based on the sharing mechanism approved by the Commission in Order No. PSC-00-1744-PAA-EI. Therefore since the total gain on non-separated sales was below the benchmark, none of the gains will be retained for the shareholders. The benchmark was calculated based on the average of actual gains for 2013 of $427,107 and 2014 of $4,493,609 and estimated gains for 2015 of $3,193,288 in accordance with Order No. PSC-00-1744-PAA-EI.

Q. Please explain the entry on Schedule E1, line 12, "Fuel Cost of Stratified Sales."

A. DEF has several wholesale contracts with SECI. One contract provides for the sale of supplemental energy to supply the portion of their load in excess of SECI's own resources. The fuel costs charged to SECI for supplemental sales are calculated on a "stratified" basis in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. There are other contracts with SECI, Reedy Creek and the City of Homestead for fixed amounts of base, intermediate, peaking and plant-specific capacity. DEF is crediting average fuel cost of the appropriate strata in accordance with Order

No. PSC-97-0262-FOF-EI. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the stratified and plant-specific sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation.

Q. Please give a brief overview of the procedure used in developing the projected fuel cost data from which the Company's fuel cost recovery factor was calculated.

A. The process begins with a fuel price forecast and a system sales forecast. These forecasts are input into the Company's production cost simulation model along with purchased power information, generating unit operating characteristics, maintenance schedules, incremental delivered fuel prices and other pertinent data. The model then computes system fuel consumption and fuel and purchased power costs. This information is the basis for the calculation of the Company's fuel cost factors and supporting schedules.

Q. What is the source of the system sales forecast?

A. System sales are forecasted by the DEF Load and Fundamentals Forecasting Department using a sales-weighted median 10-year average of weather conditions at the St. Petersburg, Orlando and Tallahassee weather stations, population projections from the Bureau of Economic and Business Research at the University of Florida, and economic assumptions from Moody's Analytics.

Q. What is the source of the Company's fuel price forecast?

A. The fuel price forecasts for natural gas and fuel oil (residual and distillate) are based on a combination of observable market data in the industry as well as hedges and/or forward contracts currently in place. For coal, a third party forecast is used. Additional details and forecast assumptions are provided in Part 1 of my exhibit.

Q. Are current fuel prices the same as those used in the development of the projected fuel factor?

A. No. Fuel prices can change significantly from day to day, particularly in the storm season. Consistent with past practices, DEF will continue to monitor fuel prices and update the projection filing prior to the November hearing if changes in fuel prices warrant such an update.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the schedules that are included in Exhibit__(CAM-3) Part 3.

A. The following schedules are included in my exhibit:

<u>Schedule E12-A – Calculation of Projected Capacity Costs – Year 2016</u>

Page 1 of Schedule E12-A includes estimated 2016 calendar year system capacity payments to qualifying facilities (QF) and other power suppliers, as well as recovery of nuclear costs pursuant to Rule 25-6.0423. The retail portion of the capacity payments is calculated using separation factors consistent with DEF's 2013 RRSSA approved in Order No. PSC-13-0598-FOF-EI. Total nuclear costs are made up of costs for the Levy Nuclear Project and the CR3 Uprate project. The revenue requirements for the CR3 Uprate project and Levy Nuclear Project are as stipulated by DEF and the RRSSA signatories and approved by bench vote of the FPSC on August 18, 2015, in Docket 150009-EI. Schedule E12-A, page 2, provides dates and MWs associated with the QF and purchase power contracts.

<u>Schedule E12-B – Calculation of Estimated/Actual True-Up - Year 2015</u>

Schedule E12-B, which is also included in Exhibit __(CAM-2) to my direct testimony filed on August 4, 2015 in the 2015 estimated/actual true-up filing, calculates the estimated true-up capacity under-recovered balance for calendar year 2015 of $38,643,256. This balance is carried forward to Schedule E12-A, line 31 to be collected from customers from January through December 2016.

<u>Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class</u>

Schedule E12-D is the calculation of the 12CP and 1/13 average demand allocators for each rate class.

<u>Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class</u>

Schedule E12-E calculates the CCR factors for capacity and CR3 Uprate costs for each rate class based on the 12CP and 1/13 annual average demand allocators from Schedule E12-D. The factors for capacity, CR3 Uprate and Levy for the Residential, General Service Non-Demand, General Service (GS-2), and Lighting secondary delivery rate class in cents per kWh are calculated by multiplying total recoverable jurisdictional capacity (including revenue taxes) from Schedule E12-A by the class demand allocation factor, and then dividing by estimated effective sales at the secondary metering level. The factors for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary factor. The factors allocate capacity, CR3 Uprate and Levy costs to rate classes in the same manner in which they would be allocated if they were recovered in base rates.

Pursuant to the 2013 RRSSA, DEF has prepared the billing rates for the demand (General Service Demand, Curtailable, and Interruptible) rate classes to be on a kilo-watt (kW) rather than a kilo-watt-hour (kWh) basis. These changes are reflected in columns 11 – 16.

Q. Has DEF used the most recent load research information in the development of its capacity cost allocation factors?

A. Yes. The 12CP load factor relationships from DEF's most recent load research conducted for the period April 2014 through March 2015 are incorporated into the capacity cost allocation factors. This information is included in DEF's Load Research Report filed with the Commission on July 31, 2015.

Q. What is the 2016 projected average retail CCR factor?

A. The 2016 average retail CCR factor is 1.199 ¢/kWh, made up of capacity and nuclear costs of 1.050 ¢/kWh and 0.149 ¢/kWh, respectively.

Q. Please explain the change in the CCR factor for the projection period compared to the CCR factor currently in effect.

A. The total projected average retail CCR factor of 1.199 ¢/kWh is 0.13 ¢/kWh or 12% higher than the 2015 factor of 1.069 ¢/kWh, approved in Order No. PSC-15-0176-TRF-EI. This increase is primarily attributable to the inclusion of capacity costs for the Osprey PPA.

Q. Does this conclude your testimony?

A. Yes

DUKE ENERGY FLORIDA, INC.

DOCKET NO. 150001-EI

GPIF Schedules for January through December 2014

DIRECT TESTIMONY OF MATTHEW J. JONES

March 17, 2015

Q. Please state your name and business address.

A. My name is Matthew J. Jones. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy as Managing Director of Analytics for Fuels and Systems Optimization.

Q. Describe your responsibilities as Director of Analytics.

A. As Managing Director of Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Florida, Inc. ("DEF" or "Company"), as well as Duke Energy Progress, Inc., Duke Energy Carolinas, Inc., Duke Energy Indiana Inc., and Duke Energy Kentucky, Inc. My responsibilities include oversight of planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of DEF's GPIF reward/penalty amount for the period of January through December 2014. This calculation was based on a comparison of the actual performance of DEF's 7 GPIF generating units for this period against the approved targets set for these units prior to the actual performance period.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. _______ (MJJ-1T), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 24-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. What GPIF incentive amount has been calculated for this period?

A. DEF's calculated GPIF incentive amount is a penalty of $8,613,797. This amount was developed in a manner consistent with the GPIF Implementation Manual. Page 2 of my exhibit shows the system GPIF points and the corresponding reward (penalty). The summary of weighted incentive points earned by each individual unit can be found on page 4 of my exhibit.

Q. How were the incentive points for equivalent availability and heat rate calculated for the individual GPIF units?

A. The calculation of incentive points was made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on each unit's Generating Performance Incentive Points Table found on pages 9 through 15 of my exhibit.

Q. Why is it necessary to make adjustments to the actual performance data for comparison with the targets?

A. Adjustments to the actual equivalent availability and heat rate data are necessary to allow their comparison with the "target" Point Tables exactly as approved by the Commission prior to the period. These adjustments are described in the Implementation Manual and are further explained by a Staff memorandum, dated October 23, 1981, directed to the GPIF utilities. The adjustments to actual equivalent availability concern primarily the differences between target and actual planned outage hours, and are shown on page 7 of my exhibit. The heat rate adjustments concern the differences between the target and actual Net Output Factor (NOF), and are shown on page 8. The methodology for both the equivalent availability and heat rate adjustments are explained in the Staff memorandum.

Q. Have you provided the as-worked planned outage schedules for DEF's GPIF units to support your adjustments to actual equivalent availability?

A. Yes. Page 23 of my exhibit summarizes the planned outages experienced by DEF's GPIF units during the period. Page 24 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA FOR FUEL AND CAPACITY COST RECOVERY FINAL TRUE-UP FOR THE PERIOD JANUARY THROUGH JULY 2015

FPSC DOCKET NO. 150001-EI

GPIF TARGETS AND RANGES FOR JANUARY THROUGH DECEMBER 2016

DIRECT TESTIMONY OF MATTHEW J. JONES

SEPTEMBER 1, 2015

Q. Please state your name and business address.

A. My name is Matthew J. Jones. My business address is 526 South Church Street, Charlotte, NC 28202.

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

A. I am employed by Duke Energy as Managing Director of Analytics for Fuels and Systems Optimization.

Q. What are your responsibilities in that position?

A. As Managing Director of Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Florida ("DEF" or the "Company"), as well as Duke Energy Progress, Duke Energy Carolinas, Duke Energy Indiana, and Duke Energy Kentucky. These responsibilities include oversight of planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. Please describe your educational background and professional experience.

A. I earned a B.A. in Anthropology from State University of New York in 2001. From 2001 until 2004, I worked as an Account Representative for National Loop Company in Green Island, NY. From 2004 until 2007, I attended graduate school at Indiana University – Bloomington, where I earned a Master of Business Administration and a Doctor of Jurisprudence, *cum laude*. In 2008, I joined Duke Energy as a Commercial Associate, spending a six month rotation working in Business Development and another six month rotation in the FERC Legal group. In 2009, I entered the Business Development Analytics group where I worked in dispatch pricing, production cost modeling, and fuel burn forecasting for the Duke Energy Carolinas system. In 2010, I entered the Integrated Resource Planning group to work on the Kentucky IRP model and later in 2010, I became the Director of Wholesale and Commodities Business Support, where I had the responsibility to manage wholesale ratemaking, dispatch pricing, production cost modeling, fuel burn forecasting, position reporting, budgeting for bulk power marketing, and general analytical support for Fuels Hedging, Bulk Power Marketing, and Wholesale Origination for North and South Carolina, Indiana and Kentucky. In July of 2012, I became the Director of Analytics for Fuels and System Optimization, where, in addition to the responsibilities outlined in the previous question, I was also given the responsibility for the Contract Administration and Fuels System Support organizations. In 2014, my title was changed to Managing Director and my organization now includes Quantitative Analytics.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a recap of actual reward / penalty for the period of January through December 2014 and also present the development of the Company's GPIF targets and ranges for the period January through December 2016. These GPIF targets and ranges have been developed from individual unit equivalent availability, average net operating heat rate targets, and improvement/degradation ranges for each of the Company's GPIF generating units, in accordance with the Commission's GPIF Implementation Manual.

Q. What GPIF incentive amount was calculated for the period January through December 2014?

A. DEF's calculated GPIF incentive amount for this period was a penalty of $8,613,797. Please refer to my testimony filed March 17, 2015 for the details of how this incentive amount was calculated.

Q. Do you have an exhibit to your testimony?

A. Yes. I am sponsoring Exhibit No. _____ (MJJ-1P), which consists of the GPIF standard form schedules prescribed in the GPIF Implementation Manual and supporting data, including outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units. This exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. Which of the Company's generating units have you included in the GPIF program for the upcoming projection period?

A. For the 2016 projection period, the GPIF program includes the following units: Bartow Unit 4, Crystal River Units 4 and 5; and Hines Units 1 through 4. Combined, these units account for 84% of the estimated total system net generation for the period.

Q. Have you determined the equivalent availability targets and improvement/degradation ranges for the Company's GPIF units?

A. Yes. This information is included in the GPIF Target and Range Summary on page 4 of my Exhibit No. ___ (MJJ-1P).

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the GPIF Implementation Manual. This includes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e., forced, partial forced, maintenance, and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate (EUOR). From operational data and these graphs, the individual target rates are determined through a review of three years of monthly data points. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage <u>rates</u> can then be converted into an overall equivalent unplanned outage <u>factor</u> (EUOF). Because factors are additive (unlike rates), the unplanned and planned outage factors (EUOF and POF) when added to the equivalent availability factor (EAF) will always equal 100%. For example, an EUOF of 15% and POF of 10% results in an EAF of 75%.

The supporting tables and graphs for the target and range rates are contained in pages 41-76 of my exhibit in the section entitled "Unplanned Outage Rate Tables and Graphs."

Q. Please describe the methodology utilized to develop the improvement/degradation ranges for each GPIF unit's availability targets?

A. The methodology described in the GPIF Implementation Manual was used. Ranges were first established for each of the four unplanned outage rates associated with each unit. From an analysis of the unplanned outage graphs, units with small historical variations in outage rates were assigned narrow ranges and units with large variations were assigned wider ranges. These individual ranges, expressed in term of rates, were then converted into a single unit availability range, expressed in terms of a factor, using the same procedure described above for converting the availability targets from rates to factors.

Q. Were adjustments made to historical unit availability to account for significant anomalies in the historical project?

A. No.

Q. Have you determined the net operating heat rate targets and ranges for the Company's GPIF units?

A. Yes. This information is included in the Target and Range Summary on page 4 of my Exhibit No. ___ (MJJ-1P).

Q. How were these heat rate targets and ranges developed?

A. The development of the heat rate targets and ranges for the upcoming period utilized historical data from the past three years, as described in the GPIF Implementation Manual. A "least squares" procedure was used to curve-fit the heat rate data to a linear relationship with Net Operating Factor (NOF), and ranges at a 90% confidence level were also established assuming a normal distribution. The analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in pages 26-40 of my exhibit in the section entitled "Average Net Operating Heat Rate Curves."

Q. How were the GPIF incentive points developed for the unit availability and heat rate ranges?

A. GPIF incentive points for availability and heat rate were developed by evenly spreading the positive and negative point values from the target to the maximum and minimum values in the case of availability, and from the neutral band to the maximum and minimum values in the case of heat rate. The fuel savings (loss) dollars were evenly spread over the range in the same manner as described for incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of the weighting factors.

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of simulations was made using a production costing model in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determine the contribution of each unit's availability to fuel savings. The heat rate contribution of each unit to fuel savings was determined by multiplying the BTU savings between the minimum and target heat rates (at constant generation) by the average cost per BTU for that unit. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

Q. What was the basis for determining the estimated maximum incentive amount?

A. The determination of the maximum reward or penalty was based upon monthly common equity projections obtained from a detailed financial simulation performed by the Company's Corporate Model.

Q. What is the Company's estimated maximum incentive amount for 2016?

A. The estimated maximum incentive for the Company is $22,342,428. The calculation of the estimated maximum incentive is shown on page 3 of my Exhibit No. ___ (MJJ-1P).

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TERRY O. JONES

DOCKET NO. 150001-EI

OCTOBER 9, 2015

Q. Please state your name.

A. My name is Terry O. Jones.

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

A. I was employed by Florida Power & Light Company ("FPL") in the nuclear fleet for 27 years. In 2013, I retired from FPL. I have been engaged by FPL as a consultant and witness in this proceeding.

Q. Please describe your educational background and professional experience.

A. I joined FPL in 1987 in the Nuclear Operations Department at Turkey Point. My positions at FPL have included Vice President, Extended Power Uprate; Vice President of Operations, Midwest Region; Vice President, Nuclear Plant Support; Vice President, Special Projects; Vice President, Turkey Point Nuclear Power Plant; Plant General Manager; Maintenance Manager; Operations Manager and Operations Supervisor. Prior to my employment at FPL, I worked for the Tennessee Valley Authority at the Browns Ferry Nuclear Plant and served in the U.S. Nuclear Navy. I hold a Bachelor of Science degree from Barry University and an MBA from the University of Miami.

Q. Please describe your experience relevant to your testimony in this docket.

A. I have been directly involved in the planning, implementation and oversight of hundreds of major nuclear projects, as well as the execution of numerous refueling outages, in my various capacities.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to Office of Public Counsel ("OPC") witness William Jacobs's recommended disallowance of recovery through the fuel clause for replacement power costs incurred as a result of the outage extension that occurred at FPL's St. Lucie Unit 2 in 2014 due to foreign material that was identified and retrieved from the primary side of the steam generator (the "FM Event"). Based on his review of the revised Root Cause Evaluation ("RCE") of the FM Event, witness Jacobs challenges decisions FPL made in the course of the incore instrumentation ("ICI") thimble replacement work performed by FPL's vendor on the upper guide structure of the reactor. I explain why witness Jacobs's opinion is misguided and lacking in merit.

Q. Please summarize your response to witness Jacobs's recommended disallowance.

A. I have spent my entire career in the nuclear industry performing work in and related to nuclear power plants. Based upon my 34 years of education, training, and experience focused on ensuring safe, reliable, efficient operation of U.S. military and commercial nuclear power plants as well as my thorough review of the documentation for the FM Event, I conclude that FPL appropriately managed the ICI thimble replacement work performed by a vendor.

The Commission should reject witness Jacobs's recommendation that FPL refund the replacement power costs associated with the FM Event. Based on the facts that I describe, FPL has satisfied the prudence standard described by FPL witness Reed. Witness Jacobs's recommendation does not refer to or rely upon specific commercial nuclear generation industry standards and fails to account for the possibility of human error, which itself is not evidence of imprudence on the part of FPL. Based on hindsight, witness Jacobs reaches the unsupported conclusion that FPL was imprudent simply because an event occurred that in hindsight everyone wishes could have been avoided.

Q. Please briefly summarize the FM Event that extended the 2014 outage at St. Lucie Unit 2.

A. On April 8, 2014, FPL had concluded a refueling outage at St. Lucie Unit 2 and was in the process of restarting the unit and restoring it to full power generation. During the starting of the reactor coolant pumps, the system designed to detect loose parts within the reactor coolant system performed as designed, indicating that there may be a loose part in the B steam generator. Consistent with plant procedures, the pumps were shut down to protect the Reactor Coolant System against damage from the potential loose part, and the plant was cooled down and depressurized. Upon inspection, a single loose part was found in the primary coolant side of Steam Generator "B" channel head. The retrieved loose part was egg-shaped, a little over an inch and a half long, and made of Type 304 stainless steel. Based on analysis by FPL and its consultants, the deformed piece appeared to be a specialized "hurricane ball" nozzle used for high pressure hydrolancing decontamination in nuclear plants.

Q. Witness Jacobs describes two RCEs that were performed for the FM Event. Please comment on the relationship between the two RCEs.

A. In May 2014, FPL completed an RCE for the FM Event that allowed for the possibility that the “hurricane ball” nozzle may have fallen into the UGS during the 2014 outage when it was identified by the loose part monitor and retrieved. Accordingly, that evaluation focused on the foreign material exclusion controls that were in place during the 2014 outage. Subsequently, however, FPL conducted a follow-up review in which it determined that the nozzle could not have fallen into the UGS during the 2014 outage but rather most likely was introduced during an earlier, 2011 outage when the nature of the outage activities would have created an opportunity for such an event. That determination led to a revised RCE, dated July 2015.

Q. Upon which RCE is witness Jacobs’s opinion about FPL’s handling of the FM Event based?

A. Witness Jacobs cites the conclusions of both RCEs in his testimony. However, his testimony does not dispute the evidence in the revised RCE that the nozzle could not have fallen into the UGS during the 2014 outage, which evidence undermines the premise of the first RCE. His testimony specifically criticizes the conclusions of the revised RCE. Accordingly, my testimony focuses on the revised RCE and witness Jacobs’s misguided criticism of it.

Q. Did you review the revised RCE?

A. Yes. I also reviewed all of the attachments to the revised RCE, including the reports prepared by FPL’s consultants.

Q. What did the revised RCE conclude regarding the cause of the FM Event?

A. According to the revised RCE, the foreign material was most likely introduced during the 2011 St. Lucie Unit 2 outage (SL2-19) as a result of the work that was performed to replace the ICI thimbles on the reactor's upper guide structure. FPL contracted Westinghouse Electric Company ("Westinghouse") to perform this ICI thimble replacement work.

Q. Was Westinghouse an appropriate vendor to hire for the ICI thimble replacement project?

A. Yes. Westinghouse, as successor to Combustion Engineering Company, is the original equipment manufacturer ("OEM") of the St. Lucie reactors. As the OEM, Westinghouse has the proprietary design information, tools and processes to effect a replacement of the ICI thimbles. Westinghouse has highly specialized expertise and an excellent track record with similar work on other nuclear units within FPL and throughout the industry.

Q. Please provide more detail regarding Westinghouse's track record regarding ICI thimble replacements.

A. In 2007, Westinghouse successfully performed the ICI thimble replacement for St. Lucie Unit 1. Additionally, Westinghouse had successfully performed this work for seven non-FPL nuclear reactors since 2005. St. Lucie Unit 2 was the last of nine nuclear reactors to have this modification performed by Westinghouse.

Q. In addition to being the OEM and having completed ICI thimble replacement work successfully in the past, what else made Westinghouse a qualified vendor?

A. Westinghouse has a robust system of practices, procedures and quality assurance that has resulted in numerous successful projects over the years.

Q. Please describe generally the contractual arrangement that FPL had with Westinghouse to perform the ICI thimble work.

A. FPL utilized a "turnkey" concept for this scope of work, which means that FPL's role was limited once work began. This is appropriate when the nuclear services vendor is highly specialized and ordinarily relied upon for its expertise. As I have explained, Westinghouse already has established processes, procedures, equipment and specialized tooling to accomplish this work. Westinghouse even has a complete mock-up of the upper guide structure to facilitate training of the personnel who are tasked with performing this work. Therefore, Westinghouse is uniquely qualified and it was appropriate for FPL to rely on its expertise.

Q. Did you review the procedures and processes that FPL and Westinghouse prepared for the ICI thimble replacement work?

A. Yes, I reviewed copies of the completed purchase order that was in place at the time; the work orders that were used by Westinghouse, the procedures used by Westinghouse, the foreign material exclusion ("FME") plan submitted by Westinghouse and approved by FPL, the division of responsibility plan, and numerous other documents. I also interviewed FPL and Westinghouse employees who were actively involved in the ICI thimble replacement project.

Q. What did you conclude based on your review of the documentation?

A. Westinghouse was responsible for execution of the ICI thimble replacement project, including the foreign material exclusion controls associated with that project. The procedures submitted by Westinghouse for the ICI thimble replacement project were of sufficient detail and had been reviewed and approved by FPL. Also, based on signatures, completed data sheets and field revisions to the procedures, I concluded that the procedures were properly utilized by the Westinghouse crews during the performance of that project.

Q. What oversight of Westinghouse did FPL provide during the ICI thimble replacement work?

A. Prior to commencement of the work, FPL reviewed and approved Westinghouse's procedures, processes and preparations. FPL had supervisors dedicated to the oversight of Westinghouse to ensure compliance with the approved procedures and processes. Specifically, personnel from FPL's reactor services group monitored the work in real time twenty-four hours a day, ensuring prompt notification when problems arose and ensuring compliance with radiological requirements and adherence to the FME plan. In addition to FPL's line personnel, FPL's quality assurance evaluators also performed surveillances of Westinghouse to verify compliance with procedures and processes.

Q. Did Westinghouse employ appropriate FME procedures for the ICI thimble replacement project?

A. Yes. In compliance with FPL's Nuclear Fleet procedure NA-AA-201, which governs the acceptance of vendor work procedures, FPL reviewed and approved

Westinghouse's procedures, work packages and FME plan prior to commencing work. For the ICI thimble replacement project, Westinghouse adopted St. Lucie's FME Procedure, known as Procedure ADM-27.13, which complied with Electric Power Research Institute and Institute of Nuclear Power Operations ("INPO") standards applicable to nuclear power plants.

Q. Please describe briefly the FME controls that Westinghouse employed for the ICI thimble replacement project.

A. Westinghouse continuously employed FME 1 controls throughout the ICI thimble replacement project. This is the strictest level of control, which was appropriate due to the complex configuration of the upper guide structure and limited inspection capability and the consequences of the introduction of foreign materials. Westinghouse performed a pre-FME inspection utilizing divers to document the initial conditions of the upper guide structure support plate and the thimble support plate.

Following a satisfactory finding of no foreign material, Westinghouse installed FME plugs in the flow holes and other openings in the upper guide structure support plate, as a barrier to foreign material potentially entering into the upper guide structure via those openings. From the time Westinghouse installed the FME plugs through the end of the project, Westinghouse maintained controls consistent with FME 1, including the use of FME monitors and logs for all tools, equipment and material that entered the ICI thimble replacement work area. Additionally, Westinghouse at all times used tools designed to be fail safe and lanyard-tied equipment to perform the work.

Q. Please describe the inspections that Westinghouse was required to perform.

A. Based on my examinations of the documentation for the ICI thimble replacement work, Westinghouse was required to perform inspections and debris removal at various stages in the project. Once the upper guide structure underwater work area had been established, Westinghouse was required to perform a foreign object search and retrieval ("FOSAR") inspection of the accessible portion of the upper guide structure.

Q. Did this inspection occur?

A. Yes. This "as found" inspection occurred just before the installation of the specifically designed FME plugs and prior to the commencement of the thimble tube removal, as directed by the procedure.

Q. What other inspections were required by the procedure?

A. Westinghouse was required to perform an FME inspection following the cutting of the ICI thimbles, preparation of the remnants and the removal of the associated debris.

Q. Did this inspection occur?

A. Yes. Westinghouse performed an FME inspection utilizing underwater cameras that reached the upper guide structure support plate and also performed underwater vacuuming to remove the debris that was generated during the cutting of the ICI thimbles.

Q. Did Westinghouse perform additional inspections?

A. Yes. Following the installation of the new thimble tubes, a diver inspected the upper guide structure and cavity floor for any remaining tooling or foreign material. Westinghouse also performed a final inspection/walkdown of the flooded refueling pool area, refuel bridge and auxiliary bridge to ensure that all tools, equipment, components and debris were removed.

Q. Did the inspections performed on the upper guide structure by Westinghouse during the 2011 St. Lucie outage satisfy the industry standard for work performed on critical components?

A. Yes, using multiple underwater cameras, including FOSAR, to inspect the upper guide structure and vacuuming to retrieve any loose debris satisfies the INPO standard for FME controls employed during the performance of complex work.

Q. Did FPL perform any inspections independent of Westinghouse?

A. Yes, once Westinghouse had completed the ICI thimble replacement work and returned the upper guide structure to FPL for installation into the reactor, FPL personnel performed a visual inspection of the upper guide structure pursuant to FPL's procedure for installation.

Q. Did any of the above inspections reveal the presence of a hurricane ball nozzle?

A. No. In spite of the FME controls in place and no fewer than four separate inspections of the upper guide structure and surrounding area during the 2011 outage, neither Westinghouse nor FPL identified a hurricane ball nozzle in the upper guide structure.

Q. Did FPL inspect the upper guide structure during the 2012 and 2014 St. Lucie 2 outages (SL2-20 and SL2-21, respectively)?

A. Yes. FPL performed a visual inspection of the accessible areas of the upper guide structure as part of the normal refueling activities that occurred during 2012 and 2014. Neither of those inspections identified a hurricane ball nozzle in the upper guide structure.

Q. Is there an industry standard for inspections of the upper guide structure to be performed upon reinstallation during a refueling outage?

A. No, there is no established industry standard for such inspections. Nor is there a consistent practice in the industry, or in some cases, even within enterprise fleets. Based on a survey of other utilities conducted by FPL's maintenance corporate functional area manager, the practices employed by other nuclear sites range from no FME inspections at all, to visual inspections and underwater camera inspections. The visual inspections performed by FPL upon reinstallation of the upper guide structure were reasonable and fall within this range of typical industry practice.

Q. Did FPL have reason to perform more intrusive inspections during either of those outages in order to detect the presence of a hurricane ball nozzle in the upper guide structure?

A. No. Based on my review of the FPL documents and interviews of FPL personnel, no work was performed on the upper guide structure during 2012 (SL2-20) and 2014 (SL2-21). Therefore, there was no occasion to perform a more intrusive inspection. FPL management decisions can be based only on what is known at the time. FPL had no reason to suspect that foreign material had been lodged in the upper guide structure when it made the decision to perform visual inspections which fell well within the range of typical industry practice.

Q. Witness Jacobs asserts that because a similar nozzle was dropped into the refueling cavity during the same outage, FPL should have been alerted to the possibility that there would be another dropped nozzle. Do you agree?

A. No. To the contrary, the fact that a dropped nozzle was reported, logged, located, and retrieved provided assurance at the time that foreign material controls were working as intended. The occurrence of this single dropped nozzle does not indicate a systemic problem. Only with hindsight could one conclude that more intrusive inspections might have been warranted.

Q. Please respond to witness Jacobs's conclusion that a complete and thorough inspection of the upper guide structure during the 2011, 2012 or 2014 outages could have identified the foreign material and prevented the outage.

A. The upper guide structure is not 100% inspectable. As I just described, Westinghouse performed multiple camera inspections during 2011, and FPL performed visual inspections of the accessible areas of the upper guide structure during 2011, 2012 and 2014, which were consistent with industry practice. Additional inspections of the same nature likely would have yielded the same result. Any statement by witness Jacobs that additional inspections could have prevented the FM Event is simply speculation.

Q. There is a "corrective action" in the revised RCE to require camera inspections of the upper guide structure in the future. Does this indicate that a hurricane ball nozzle likely would have been found if FPL had performed a camera inspection of the upper guide structure?

A. Absolutely not. As I previously discussed, Westinghouse performed an FME inspection utilizing underwater cameras during the ICI thimble replacement work, which did not detect a hurricane ball nozzle. Moreover, given that the upper guide structure is not 100% inspectable, a camera inspection of the periphery of the upper guide structure would be only a slight enhancement to a visual inspection. It would not be able to detect small objects lodged within the upper guide structure.

Q. In your opinion, what efforts would have had to be undertaken to identify the hurricane ball nozzle in the upper guide structure?

A. It depends on where the hurricane ball nozzle was lodged. If it was lodged inside non-accessible areas, FPL would have to deploy boroscopic inspection tools with radiation-hardened cameras and would have to perform high-risk diving operations in high radiation fields, which would have taken many days to accomplish and thus extended the 2011 outage. Even efforts of this magnitude could not result in a 100% inspection of the upper guide structure.

It is important to keep in mind as well that, prior to the activation of the loose parts monitor alarms at the end of the 2014 outage and subsequent location of the FM, FPL had no reason to expect that a hurricane ball nozzle was missing. It is only with hindsight that witness Jacobs can claim that FPL should have been undertaking extraordinary inspections in search of foreign material.

Q. Did the Westinghouse FME controls also provide for tools to be checked into and out of the upper guide structure work area?

A. Yes.

Q. Did Westinghouse report any unresolved discrepancies in the FME control or material control logs that would have suggested that a nozzle might have been lost in the upper guide structure work area?

A. No. At the end of each shift, all FME control and material control logs were reconciled. The ICI thimble replacement project was closed out without any unresolved discrepancies.

Q. Witness Jacobs also speculates that FPL did not properly inventory tools and attachments. What is the standard utility practice regarding accounting for nozzles?

A. A nozzle, or more specifically here, a hydrolancing nozzle, is one component of a spray wand assembly. Because this is not a complex tool and each component is mechanically secured, industry standard does not require sites to log the barrel, trigger, nozzle and other components of a spray wand as separate items. Rather, pursuant to INPO guidelines for foreign material control, the industry standard for the deployment of a simple tool such as a spray wand is to inspect and log that tool as a singular item and to inspect it upon exit to verify no equipment breakage. By comparison, a complex tool such as an underwater robotic camera would be photographed upon entry. Upon exit, it would be inspected against the photographs to ensure no equipment breakage.

Witness Jacobs emphasizes the need to employ “good utility practices,” which he explains are “practices, methods and acts engaged in or approved by a significant portion of the electric utility industry,” but he fails to point to any industry practice that requires nozzles to be logged individually.

Q. Did the FME Plan employed by Westinghouse during the ICI thimble replacement project comply with the industry standard you described?

A. Yes, it did.

Q. In your opinion as an experienced nuclear professional, were the decisions and actions of FPL management appropriate based upon the information available to FPL at the time?

A. Yes. FPL’s decision in 2011 to select Westinghouse to perform the ICI thimble replacement work was appropriate given Westinghouse’s knowledge, experience and successful track record. FPL reviewed and approved Westinghouse’s processes, procedures and policies to ensure that an appropriate FME Plan that more than satisfied industry standard was in place. FPL provided constant management oversight of Westinghouse, both from the line organization and from FPL’s quality assurance organization. FPL performed visual inspections consistent with industry practice in 2011, 2012 and 2014 during the reassembly of the upper guide structure. Unfortunately, despite all of these efforts, it is apparent that human error by contracted personnel performing the ICI thimble replacement project occurred such that a foreign object was introduced and went undetected.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 150001-EI

AUGUST 4, 2015

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

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

Q. What are your responsibilities in that position?

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

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the United States Naval Academy 1985. I have 14 years of power plant and production experience in various managerial and executive positions within Duke Energy managing Fossil Steam Operations, Combustion Turbine Operations and Nuclear Plant Operations. While at Duke Energy I have managed new unit projects from construction to operations, and I have extensive contract negotiation and management experience. My prior experience also includes nuclear engineering and operations experience in the United States Navy and project management, engineering, supervisory and management experience with a pulp, paper and chemical manufacturing company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with information related to the Hines Unit 2 forced outage that occurred on July 7, 2014, including background information on the event that led to the outage, an explanation of DEF's responsive actions, a presentation of DEF's root cause analysis and findings, an explanation of insurance coverage, and an explanation of DEF's reasonable and prudent restoration actions.

Q. Please provide a summary of your testimony.

A. On July 7, 2014, a mechanical failure occurred at the Hines Energy Center ("HEC"), specifically Power Block 2 ("Hines 2"), resulting in a forced outage that concluded when the unit was brought back on-line on June 19, 2015. DEF performed a Root Cause Analysis ("RCA") that determined the cause of the failure was separation of the High Pressure-Intermediate Pressure ("HP-IP") coupling resulting from the failure of the HP-IP coupling bolts. After investigation, the root cause analysis team ("RCA Team") determined that the HP-IP coupling bolts failed due to being improperly tightened by the Original Equipment Manufacturer ("OEM"), Siemens, after the March 2011 50,000-hour inspection. This failure was caused by events beyond DEF's control, and DEF could not have reasonably prevented the subsequent damage from occurring.

After the fire, DEF created a Restoration Team to oversee returning Hines 2 to service. As a result of the Restoration Team's aggressive and efficient oversight, DEF returned Hines 2 to service in a timely manner, minimizing the length and cost of the outage. DEF's actions prior to and in the wake of the Hines 2 event were reasonable and prudent.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the DEF RCA Report, attached as Exhibit No. __ (JS-1). I am also sponsoring a composite exhibit consisting of a timeline detailing major project restoration milestones and photographs of significant restoration events as Exhibit No. __(JS-2).

Q: Is the RCA considered confidential by the Company?

A: Yes. The RCA and portions of my testimony discussing the RCA's findings are confidential because DEF's rights under its insurance policies covering Hines 2 have been subrogated to its insurers. In order to protect those subrogated rights and therefore DEF's and its insurers' competitive business interests, this information has been treated by the Company as proprietary confidential business information and has not been made publicly available.

Q. Please summarize the events leading up to the Hines 2 event.

A. On July 7, 2014, the Hines 2 Steam Turbine suddenly and unexpectedly tripped offline. Site personnel heard a deep, loud rumbling sound near Hines 2 followed by a fire on the west side of the Steam Turbine enclosure. The fire spread to the third elevation of the enclosure and migrated to the east side, igniting the generator inlet air filter structure. In response to the spreading fire, station personnel shut down the associated combustion turbines and ancillary equipment. All personnel were evacuated and accounted for. Emergency personnel responded to the event and site personnel took additional precautions including a fire watch through the evening to monitor for any secondary ignition. There were no injuries associated with this event.

Q. What actions did DEF take in response to the fire and resulting forced outage?

A. The Company took three primary actions in the wake of the event: a root cause team was established to investigate the incident and prepare a root cause analysis; a restoration team was formed to bring the unit back on-line; and DEF began the process of making a claim with its insurers.

Q. Please describe the process DEF followed to ascertain the root cause of the event.

A. DEF created a RCA Team consisting of internal experts to investigate and determine the root cause of the event. The RCA Team consisted of six individuals with expertise in engineering, operations and process, and human performance.

Following industry standard procedures, the RCA Team employed specific tools used to determine potential root cause(s) including: interviews, event and causal factor review ("E&CF"), flawed barrier analysis, change analysis, component analysis, visual inspections of the equipment, photographs taken following the event, engineering calculations and measurements, and detailed review of outage reports and maintenance logs.

REDACTED

Q. Please describe the RCA Team's conclusions.

A. The DEF RCA Team determined that the root cause of the Hines 2 failure and ensuing forced outage was the separation of the HP-IP coupling resulting from the failure of the HP-IP coupling bolts. The coupling failed over time due to improper reassembly during the 2011 outage which was performed by the OEM. [redacted]

The RCA Team reviewed the 50,000 hour inspection performed in March 2011 and discovered that the [redacted]. If the bolts were properly tightened, a one-time axial, non-vibrational force of 1,540,000 pounds would have been required to break all bolts simultaneously. Neither the RCA Team nor the OEM have been able to establish a mechanism that could produce a force of this magnitude other than the failure mechanism described above, thereby confirming the RCA conclusion.

Q. Did the RCA Team consider alternative potential root causes?

A. Yes, the RCA Team evaluated L-0 Blade failure as a potential cause, but that theory was ultimately rejected.

REDACTED

Q. Why did the RCA Team reject the L-0 Blade failure theory?

A. During this event, the Hines 2 Steam Turbine experienced a complete failure of the 42-inch titanium, last stage (L-0) LP turbine blade row as well as significant other turbine, generator, and site damage. Because of this fact and due to past industry failures in some L-0 blades in other non-Duke Energy plants, DEF examined an L-0 blade failure as a potential root cause. During the RCA investigation, however, DEF discovered [redacted]

[redacted] As mentioned above, both the RCA Team and OEM have been unable to create a scenario that would yield the amount of force necessary to break all of the bolts after L-0 blade failure had the HP-IP coupling bolts been properly tightened, further indicating that the HP-IP bolts failed prior to L-0 blade failure. Thus, DEF reasonably concluded that it appears to be physically impossible for an L-0 blade failure to be the cause of the event. The root cause report that is Exhibit No. __ (JS-1) to my testimony provides further detail on how the RCA conclusion was investigated.

Q. Does DEF carry insurance on Hines 2?

A. Yes, DEF carries insurance that covers some of the costs associated with the restoration at Hines 2, but that insurance does not cover replacement fuel costs. Currently, the insurance industry does not offer a reasonably priced replacement fuel cost product, and unlike the mutual insurance company created to provide coverage for replacement power in the event of nuclear outages (Nuclear Electric Insurance Limited ("NEIL")), there is no utility industry collective that provides insurance for replacement power for fossil plant outages. The costs DEF incurred to restore the unit that are covered by DEF's various insurance policies are not at issue in this docket, and any claims that may arise against the OEM as a result of the Hines 2 event are subrogated to DEF's insurers.

At issue in this docket are the replacement power costs incurred as a result of the Hines 2 event. The total replacement power costs are reasonable and were prudently incurred in response to the Hines 2 outage. The calculation of those costs is discussed in detail in Mr. Menendez's testimony.

Q. What restoration process did DEF follow to bring Hines 2 back into service?

A. DEF first established a Restoration Team of internal experts to assess the level of damage and formulate a strategy for bringing the unit back online. The team was charged with determining what equipment could be repaired and/or refurbished and what equipment needed to be replaced, developing a project schedule and cost estimate, and overseeing the work required to bring the unit back into service in a reasonable and prudent timeframe and within the proposed cost estimates.

The Restoration Team developed a schedule of major milestones to minimize the recovery time, including milestones such as safety training for the RCA and Recovery Teams, beginning and completing the RCA, beginning and completing the equipment assessment, beginning reassembly, and finally returning the unit to service. A copy of a general restoration milestone timeline and photographs of key restoration activities are included as Exhibit No. __ (JS-2) to my testimony.

Q. Has Hines 2 returned to service?

A. Yes, the Unit was returned to service on June 19, 2015.

Q. Please provide a summary of the activities that needed to take place to return the unit to service.

A. Immediately after the fire, station personnel surveyed the affected area and safely secured the site. Site personnel started environmental remediation to contain and clean up oil spilled from the event, ultimately removing and replacing 2100 tons of dirt and rock. An assessment team of DEF subject matter experts ("SME") surveyed the entire power block to outline visible repairs. Their recommendations were:

1. Hire the OEM to rebuild the turbine, generator and associated auxiliary equipment;
2. Engineering assessment and replacing of the damaged steam turbine pedestal;
3. Remove and replace entire runs of damaged cables, instrumentation, and controls;
4. Fully test the station's generator step up ("GSU") transformers, iso-phase bus ducts, and repair as necessary;
5. Evaluate the steam turbine high energy piping and hangers for deformation and weld failures;
6. Retube the condenser (approximately 14,000 tubes) and its expansion joint;
7. Rebuild the damaged water treatment lab testing/repairing/replacing the lab equipment;
8. Properly lay up the combustion turbines and the heat recovery steam generator ("HRSG");
9. Replace the damaged steam turbine enclosures and associated structural members;

10. Evaluate current fire protection system and bring to current new requirements; and
11. Perform a "new plant start up" using the Duke Plant Major Construction Division.

The project team set up an integrated schedule, which included OEM shop activities across the world, to minimize any work flow or critical path issues. This schedule was based around the OEM's three phase repair plan: Phase I - demolition to August 31, 2014; Phase II - shop manufacturing and repair of components – September 2014 – May 2015; Phase III - field assembly and startup of the turbine generator January 2015 – June 2015.

In the first phase of the recovery plan, the steam turbine weather enclosure was safely removed with the removal of the turbine taking precedent. That work was slowed by the extensive internal damage found and the desire to salvage as many components as possible. Concurrently, the restoration team worked on removing damaged cabling and ongoing detailed component assessments. The cable replacement effort entailed removing approximately 211,789 linear feet of cable that affected numerous components throughout the power block.

Once demolition and environmental remediation was complete, the restoration team focused on procurement and scope development as work packages were handed over from the SME assessment team. Work continued on cable removals as well as removal of damaged components, and contractors started on iso-phase inspection, generator/GSU testing, condenser repairs and an engineering assessment of the damaged steam turbine pedestal.

In the last quarter of 2014, work continued on the unit's condenser, and all the internal tubing was removed. Assessment of the damaged steam turbine pedestal was completed and an engineered work scope was prepared which allowed concrete demolition to begin. Plans were finalized and equipment was procured to place the combustion turbines and HRSG in a preserved state. The combustion turbines, HRSG and generator were placed on an atmospheric climate control for preservation, and work continued on steam turbine pedestals, condenser structural repairs, auxiliary piping and conduit/cable installation.

In the first quarter of 2015, OEM teams began to mobilize concentrating on piping demolition and fabrication within their scope and re-assembly of the generator. The engineered steam turbine pedestal restoration was completed ahead of schedule and turned over to the OEM to begin the precision re-assembly of the steam turbine pedestal bearing supports and turbine alignment. Structural repairs of the condenser and re-tubing were completed. Additionally, the generator rotor was installed and initial alignments completed. OEM crews commenced reestablishment of turbine auxiliary piping, installing the bearing pedestals with instrumentation, and the HP turbine assembly. The Duke Energy commissioning team commenced start up activities with steam piping cleanliness air blows and the staging of the equipment / piping for the HRSG chemical cleaning.

In the second quarter of 2015, damaged conduit and cable work was completed and the commissioning team entered start-up mode commencing with the HRSG chemical cleaning, lube oil and hydraulic control piping flushes, the operational function testing of associated station equipment and instrumentation, and controls calibrations. The steam turbine weather enclosure structural framing was set and acoustic panels arrived, and the OEM installed the IP/LP turbine and completed installation of the steam turbine valves, hi-pressure steam piping, and piping supports and hangers. Additionally, upon the completion of the post-outage start up procedure, the combustion turbines were started, functionally checked, and synchronized to the electrical grid in anticipation of steam turbine unit testing.

In June 2015, the commissioning team completed all electrical testing and instrumentation checks. On June 9, a steam turbine vacuum was established and steam purity checks were completed on June 15. Upon completion of the commissioning team's checklist and start up plan, the steam turbine was rolled to full load and synchronized to the electrical grid on June 18, and the power block was returned to the DEF Energy Control Center for dispatch on June 19, 2015 at 07:13.

Q. Could DEF have reasonably prevented the event and the ensuing outage at Hines 2?

A. No, the event and resulting outage were caused by circumstances beyond DEF's reasonable control, as demonstrated by the RCA. DEF was not at fault.

Q. Did DEF act reasonably and prudently to restore Hines 2 to service in a timely fashion?

A. Yes, DEF took reasonable and prudent steps to develop a restoration team and guiding processes to restore Hines 2 to service. The restoration team followed those processes and Hines 2 was successfully brought back on line in a timely manner.

Q. Does that conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
C. Shane Boyett
Docket No. 150001-EI
Date of Filing: March 3, 2015

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida in 2001 with a Bachelor of Science Degree in Business Administration. I also hold a Masters in Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist where I worked for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power's Financial Planning department as a Financial Analyst where I worked until being pr omoted to my current position of Supervisor of Regulatory and Cost Recovery. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery department.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the actual true-up amounts for the period January 2014 through December 2014 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will also present the actual benchmark level for the calendar year 2015 gains on non-separated wholesale energy sales eligible for a shareholder incentive and the amount of gains or losses from hedging settlements for the period January 2014 through December 2014.

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

A. Yes. My exhibit consists of 1 schedule that relates to the fuel and purchased power cost recovery actual true-up, 4 schedules that relate to the capacity cost recovery actual true-up, and 1 appendix that includes Schedules A-1 through A-9 and A-12 for the period January 2014 through December 2014, previously filed monthly with this Commission. Each of these documents was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibit consisting of 5 schedules and 1 appendix be marked as Exhibit No. _____ (CSB-1).

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

A. Yes.

Q. Which schedules of your exhibit relate to the calculation of the fuel and purchased power cost recovery true-up amount?

A. Schedule 1 of my exhibit relates to the fuel and purchased power cost recovery true-up calculation for the period January 2014 through December 2014. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for January 2014 through December 2014 are incorporated herein in Appendix 1.

Q. What is the actual fuel and purchased power cost true-up amount related to the period of January 2014 through December 2014 to be refunded or collected through the fuel cost recovery factors in the period January 2016 through December 2016?

A. A net amount to be refunded of $8,084,753 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $8,084,753 was calculated by taking the difference in the estimated and actual over/under-recovery amounts for the period January 2014 through December 2014. The estimated under-recovery was $43,001,980 as shown on Schedule E-1B, Line 6 + 7 + 8 filed July 25, 2014. The actual under-recovery was $34,917,227 which is the sum of the Period-to-Date amounts on lines 7, 8, and 12 shown on the December 2014 Schedule A-2, page 2 of 3, included in Appendix 1. Additional details supporting the approved estimated true-up amount are included on Schedules E1-A and E1-B filed July 25, 2014.

Q. Has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2014 gains?

A. Yes, the three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2012 through 2014 is calculated as follows:

Year	Actual Gain
2012	519,586
2013	194,730
2014	1,319,633
Three-Year Average	$ 677,983

Q. What is the actual threshold for 2015?

A. The actual threshold for 2015 is $677,983.

Q. Is Gulf seeking to recover any gains or losses from hedging settlements for the period of January 2014 through December 2014?

A. Yes. On line 2 of Schedule A-1, Period-to-Date, for December 2014 included in Appendix 1, Gulf has recorded a net gain of $1,910,889 related to hedging activities in 2014. Mr. Ball addresses the details of those hedging activities in his testimony.

Q. Mr. Boyett, you stated earlier that you are responsible for the purchased power capacity cost recovery true-up calculation. Which schedules of your exhibit relate to the calculation of this amount?

A. Schedules CCA-1, CCA-2, CCA-3 and CCA-4 of my exhibit relate to the purchased power capacity cost recovery true-up calculation for the period January 2014 through December 2014. In addition, Capacity Cost Recovery Schedule A-12 for the months of January 2014 through December 2014 is included in Appendix 1.

Q. What is the actual purchased power capacity cost true-up amount related to the period of January 2014 through December 2014 to be refunded or collected in the period January 2016 through December 2016?

A. An amount to be collected of $893,047 was calculated as shown on Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $893,047 was calculated by taking the difference in the estimated January 2014 through December 2014 over-recovery of $1,263,407 and the actual over-recovery of $370,360, which is the sum of lines 10, 11, and 14 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in FPSC Order No. PSC-14-0701-FOF-EI dated December 19, 2014. Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed July 25, 2014.

Q. Please describe Schedules CCA-2 and CCA-3 of your exhibit.

A. Schedule CCA-2 shows the calculation of the actual under-recovery of purchased power capacity costs for the period January 2014 through

December 2014. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the under-recovery for the period January 2014 through December 2014.

Q. Please describe Schedule CCA-4 of your exhibit.

A. Schedule CCA-4 provides additional details related to Lines 1 and 2 of Schedule CCA-2.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
C. Shane Boyett
Docket No. 150001-EI
Date of Filing: August 4, 2015

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida in 2001 with a Bachelor of Science degree in Business Administration. I also hold a Master of Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist where I worked for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power's Financial Planning department as a Financial Analyst where I worked until being promoted to my current position of Supervisor of Regulatory and Cost Recovery. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery department.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes, I have.

Counsel: We ask that Mr. Boyett's Exhibit consisting of fourteen schedules be marked as Exhibit No. ____ (CSB-2).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2015 through December 2015 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2015 through December 2015 set forth in your exhibit?
A. Yes, these documents were prepared under my supervision.

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

Q. How were the estimated true-ups for the current period calculated for both fuel and purchased power capacity?
A. In each case, the estimated true-up calculations include six months of actual data and six months of estimated data.

Q. Mr. Boyett, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2016 through December 2016?

A. The fuel cost recovery true-up for this period is a decrease of 0.1755 ¢/kWh. As shown on Schedule E-1A, this includes an estimated over-recovery for the January through December 2015 period of $11,285,334. It also includes a final over-recovery for the January through December 2014 period of $8,084,753 (see Schedule 1 of Exhibit CSB-1 in this docket filed on March 3, 2015). The resulting total over-recovery of $19,370,087 will be refunded during 2016.

Q. Mr. Boyett, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedules CCE-1A, CCE-1B and CCE-4 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2016 through December 2016 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2016 through December 2016?

A. The true-up for this period is a decrease of 0.0002 ¢/kWh as shown on Schedule CCE-1A. This includes an estimated over-recovery of $910,906 for January 2015 through December 2015. It also includes a final under-recovery of $893,047 for the period of January 2014 through December 2014 (see Schedule CCA-1 of Exhibit CSB-1 in this docket filed March 3, 2015). The resulting total over-recovery of $17,859 will be refunded during 2016.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
C. Shane Boyett
Docket No. 150001-EI
Date of Filing: September 1, 2015

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida in 2001 with a Bachelor of Science Degree in Business Administration. I also hold a Master of Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist where I worked for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power's Financial Planning department as a Financial Analyst where I worked until being promoted to my current position of Supervisor of Regulatory and Cost Recovery. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery department.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 2016 through December 2016. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2016 through December 2016.

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

A. Yes. I have one exhibit consisting of 15 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibit consisting of 15 schedules, be marked as Exhibit No. _____(CSB-3)

Q. Mr. Boyett, what is the levelized projected fuel factor for the period January 2016 through December 2016?

A. Gulf has proposed a levelized fuel factor of 3.650¢/kWh. This factor is based on projected fuel and purchased power energy expenses for January 2016 through December 2016 and projected kWh sales for the same period, and includes the true-up and GPIF amounts.

Q. How does the levelized fuel factor for the projection period compare with the levelized fuel factor for the current period?

A. The projected levelized fuel factor for 2016 is 0.685¢/kWh more or 16 percent lower than the levelized fuel factor in place January through December 2015.

Q. Please explain the calculation of the fuel and purchased power expense true-up amount included in the levelized fuel factor for the period January 2016 through December 2016.

A. As shown on Schedule E-1A of my exhibit, the true-up amount of $19,370,087 to be refunded during 2016 includes an estimated over-recovery for the January through December 2015 period of $11,285,334 plus a final over-recovery for the period January through December 2014 of $8,084,753. The estimated over-recovery for the January through December 2015 period includes 6 months of actual data and 6 months of estimated data as reflected on Schedule E-1B.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2014 through December 2014?

A. The GPIF result is shown on Line 31 of Schedule E-1 as an increase of 0.0240¢/kWh to the levelized fuel factor, thereby rewarding Gulf $2,648,312.

Q. What is the appropriate revenue tax factor to be applied in calculating the levelized fuel factor?

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs as shown on Line 29 of Schedule E-1.

Q. Mr. Boyett, how were the line loss multipliers used on Schedule E-1E calculated?

A. The line loss multipliers were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest MWh Load Flow Allocators.

Q. Mr. Boyett, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, and OSIII?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 3.678¢/kWh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. Mr. Boyett, how were the time-of-use fuel factors calculated?

A. The time-of-use fuel factors were calculated based on projected loads and system lambdas for the period January 2016 through December 2016. These factors included the GPIF and true-up and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2015 and how would the change affect the cost of 1,000 kWh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2015 is 4.369¢/kWh compared with the proposed factor of 3.678¢/kWh. For a residential customer who is billed for 1,000 kWh in

January 2016, the fuel portion of the bill would decrease from $43.69 to $36.78.

Q. Has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my exhibit. These costs represent the estimated averages for the period from January 2016 through December 2017.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2016 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-AAA-EI, a benchmark level of $752,900 has been calculated for 2016 as follows:

2013 actual gains	194,730
2014 actual gains	1,319,633
2015 estimated gains	744,338
Three-Year Average	$ 752,900

This amount represents the minimum projected threshold for 2016 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2016.

Q. You stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1A and CCE-1B, Schedule CCE-2, and Schedule CCE-4 of my exhibit CSB-3 relate to the calculation of the PPCC recovery factors for the period January 2016 through December 2016.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Ball has provided me with Gulf's projected purchased power capacity transactions. Gulf's total projected net capacity expense, which includes a credit for transmission revenue, for the period January 2016 through December 2016, is $88,074,632. The jurisdictional amount is $85,495,331. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

Q. What methodology was used to allocate the capacity payments by rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology approved by the Commission in Order No. PSC-12-0179-FOF-EI issued April 3, 2012, in Docket No. 110138-EI. For purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs by rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study approved by the Commission in Order No. PSC-12-0179-FOF-EI issued April 3, 2012, in Docket No. 110138-EI.

Q. How were the allocation factors calculated for use in the PPCC Recovery Clause?

A. The allocation factors used in the PPCC Recovery Clause have been calculated using the 2012 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on page 1 of Schedule CCE-2.

Q. Please describe the calculation of the ¢/kWh factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, 12/13th of the jurisdictional capacity cost to be recovered is allocated by rate class based on the demand allocator. The remaining 1/13th is allocated based on energy.

Gulf has calculated the PPCC factor for the LP/LPT rate classes based on kilowatt (kW) rather than kilowatt hour (kWh) in accordance with Order No. PSC-13-0670-S-EI issued December 9, 2013 in Docket No. 130140-EI. The total revenue requirement assigned to rate class LP/LPT shown in column E is then divided by the sum of the projected billing demands (kW) for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each LP/LPT customer's billing demand (kW) to calculate the amount to be billed each month.

For all other rate classes, the total revenue requirement assigned to each rate class shown in column E is then divided by that class's projected kWh sales for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each customer's total kWh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1,000 kWh?

A. The purchased power capacity costs recovered through the clause for a residential customer who is billed for 1,000 kWh will be $9.19.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?

A. The fuel and capacity factors will be effective beginning with Cycle 1 billings in January 2016 and continuing through the last billing cycle of December 2016.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. L. Nicholson
Docket No. 150001-EI
Date of Filing: March 17, 2015

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

A. My name is Cody L. Nicholson. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from Auburn University in 1998. I joined Southern Company with Alabama Power in 1996 as a summer intern. Upon graduation in 1998, I joined Southern Company Services (SCS), a subsidiary of Southern Company. During my time at SCS, I worked in Farley Project and in Generating Plant Performance (GPP), where I progressed through various engineering positions with increasing responsibilities. My primary responsibility in Farley Project was to coordinate design changes to Plant Farley. My primary responsibility in GPP was to conduct heat rate tests and performance tests on plant equipment. I joined Southern Nuclear Operating Company (SNC) in 2011. At SNC, my primary responsibility was to coordinate responses to requests from the U. S. Nuclear Regulatory Commission for various projects. I joined SCS in 2014 as a Performance and Reliability Engineer, where my primary responsibility was to report key performance indicators on a monthly basis. I joined Gulf Power in 2015 in my current job position as Power Generation Specialist, Senior as previously mentioned in my testimony. In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

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

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2014, through December 31, 2014.

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

A. Yes. I have prepared an exhibit consisting of five schedules.

Counsel: We ask that Mr. Nicholson's Exhibit consisting of five schedules be marked as Exhibit No. _______ (CLN-1).

Q. Is there any information that has been supplied to the Commission pertaining to this GPIF period that requires amendment?

A. Yes. Some corrections have been made to the actual unit performance data, which was submitted monthly to the Commission during this time period. These corrections are based on discoveries made during the final data review to ensure the accuracy of the information reported in this filing. The actual unit performance data tables on pages 14 through 25 of

Schedule 5 of my exhibit incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

Q. Please review the Company's equivalent availability results for the period.

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 13 of Schedule 5. Pages 3 through 8 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by FPSC Order No. PSC-13-0665-FOF-EI is on page 9 of Schedule 2. The results are: Crist 5, -10.00 points; Crist 6, 6.25 points; Crist 7, 10.00 points; Smith 1, -1.88 points; Smith 2, -3.60 points; and Smith 3, 10.00 points.

Q. What were the heat rate results for the period?

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 7 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on pages 8 through 13 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in August 2013, are shown on page 15 of Schedule 3. As calculated on page 16 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points: Crist 5, +1.56 points;

Crist 6, +0.00 points; Crist 7, +10.00 points; Smith 1, -5.25 points; Smith 2, +0.00 points, and Smith 3, +10.00 points.

Q. What number of Company points was achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was +5.92 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $2,648,312.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 9 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 16 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $2,648,312 as provided for by the GPIF plan.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
C. L. Nicholson
Docket No. 150001-EI
Date of Filing: September 1, 2015

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

A. My name is Cody L. Nicholson. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from Auburn University in 1998. I joined Southern Company with Alabama Power in 1996 as a summer intern. Upon graduation in 1998, I joined Southern Company Services (SCS), a subsidiary of Southern Company. During my time at SCS, I worked in Farley Project and in Generating Plant Performance (GPP), where I progressed through various engineering positions with increasing responsibilities. My primary responsibility in Farley Project was to coordinate design changes to Plant Farley. My primary responsibility in GPP was to conduct heat rate tests and performance tests on plant equipment. I joined Southern Nuclear Operating Company (SNC) in 2011. At SNC, my primary responsibility was to coordinate responses to requests from the U. S. Nuclear Regulatory Commission for various projects. I joined SCS in 2014 as a Performance and Reliability Engineer, where my primary responsibility was to report key performance indicators on a monthly basis. I joined Gulf Power in 2015 in my current job position as Power Generation Specialist, Senior as previously mentioned in my testimony. In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2016 through December 31, 2016.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes. I have prepared one exhibit entitled CLN-2 consisting of three schedules.

Q. Was this exhibit prepared by you or under your direction and supervision?
A. Yes, it was.

Counsel: We ask that Mr. Nicholson's exhibit consisting of three schedules be marked for identification as Exhibit___(CLN-2).

Q. Which units does Gulf propose to include under the GPIF for the subject period?

A. We propose that Crist Units 6 and 7, Daniel Units 1 and 2, and Smith Unit 3, be included as the Company's GPIF units. The projected net generation from these units is approximately 96% of Gulf's projected net generation for 2016.

Q. For these units, what are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2016 through December 31, 2016?

A. I would like to refer you to page 23 of Schedule 1 of my exhibit where these targets are listed.

Q. How were these proposed target heat rates determined?

A. They were determined according to the GPIF Implementation Manual procedures for Gulf.

Q. Describe how the targets were determined for Gulf's proposed GPIF units.

A. Page 2 of Schedule 1 of my exhibit shows the target average net operating heat rate equations for the proposed GPIF units and pages 4 through 20 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 21 and 22 of Schedule 1 present the calculations that provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit indicated on page 23 of Schedule 1 of your exhibit calculated according to the appropriate GPIF Implementation Manual procedures?
A. Yes.

Q. What are the proposed target, maximum, and minimum equivalent availabilities for Gulf's units?
A. The target, maximum, and minimum equivalent availabilities are listed on page 4 of Schedule 2 of my exhibit.

Q. How were the target equivalent availabilities determined?
A. The target equivalent availabilities were determined according to the standard GPIF Implementation Manual procedures for Gulf and are presented on page 2 of Schedule 2 of my exhibit.

Q. How were the maximum and minimum attainable equivalent availabilities determined for each unit?
A. The maximum and minimum attainable equivalent availabilities, which are presented along with their respective target availabilities on page 4 of Schedule 2 of my exhibit, were determined per GPIF Implementation Manual procedures for Gulf.

Q. Mr. Nicholson, has Gulf completed the GPIF minimum filing requirements data package?

A. Yes, we have completed the minimum filing requirements data package. Schedule 3 of my exhibit contains this information.

Q. Mr. Nicholson, would you please summarize your testimony?
A. Yes. Gulf asks that the Commission accept:

1. Crist Units 6 and 7, Daniel Units 1 and 2, and Smith Unit 3 for inclusion under the GPIF for the period of January 1, 2016 through December 31, 2016.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 23 of Schedule 1 and also on page 5 of Schedule 3 of my exhibit.

3. The target, maximum attainable, and minimum attainable equivalent availabilities, as proposed by the Company and as shown on page 4 of Schedule 2 and also on page 5 of Schedule 3 of my exhibit.

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and also on pages 17 through 26 of Schedule 3 of my exhibit, for use in adjusting the annual actual unit heat rates to target conditions.

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

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 3rd day of November, 2015.

Linda Boles

LINDA BOLES, CRR, RPR
FPSC Official Hearings Reporter
(850) 413-6734