BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20170001-EI

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.
_________________________________/

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PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN JULIE I. BROWN
COMMISSIONER ART GRAHAM
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER DONALD J. POLMANN
COMMISSIONER GARY F. CLARK

DATE: Wednesday, October 25, 2017

TIME: Commenced at 12:30 p.m.
Concluded at 2:00 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
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APPEARANCES:

J.R. KELLY, PUBLIC COUNSEL; PATRICIA A. CHRISTENSEN, ERIK SAYLER, 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 D. BEASLEY and J. JEFFRY WAHLEN, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric 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.

STEVEN R. GRIFFIN and RUSSELL A. BADDERS and ESQUIRES, Beggs & Lane, P.O. Box 12950, Pensacola, Florida 32591-2950; JEFFREY A. STONE, ESQUIRE, One Energy Place, Pensacola, Florida, 32520, appearing on behalf of Gulf Power Company.

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

APPEARANCES:

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

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

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

SUZANNE BROWNLESS and DANIJELA JANJIC ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

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

I N D E X

WITNESSES

P R O C E E D I N G S

CHAIRMAN BROWN: Thank you so much.

And we are going to take appearances. There are five dockets and, staff, it's -- your suggestion that we take up the appearances all at once, correct?

MS. DUVAL: Yes, ma'am.

CHAIRMAN BROWN: Okay. So all parties, please, when I go through the list, can you please enter your appearances and declare which dockets you are entering an appearance for? Starting with Florida Power & Light.

MR. BUTLER: Thank you, Madam Chairman.

John Butler and Wade Litchfield appearing in dockets 01, 02 and 07. Also appearing -- on behalf of Florida Power & Light Company.

Also appearing for Florida Power & Light Company in the 01 docket are Maria Moncada and Will Cox. In the 02 docket, Ken Rubin, and in the 07 docket, Jessica Cano.

CHAIRMAN BROWN: Okay.

MR. BUTLER: Thank you.

CHAIRMAN BROWN: Thank you.

Duke, Matt Bernier.

MR. BERNIER: Thank you, Madam Chairman.

Good afternoon, Commissioners. Matt Bernier for Duke Energy. I am entering an appearance in the 01, 02 and 07 dockets. And I would also like to enter an appearance for Dianne Triplett.

Thank you.

CHAIRMAN BROWN: Thank you.

Mr. Beasley.

MR. BEASLEY: Thank you, Madam Chair, Commissioners.

James Beasley, appearing with Jeff Whalen for Tampa Electric Company in 01, 02 and 07 dockets.

CHAIRMAN BROWN: Thank you.

Gulf.

MR. BADDERS: Good afternoon. Russell Badders on behalf of Gulf Power, in the 01, 02 and 07 dockets. I would also like to enter an appearance for my partner, Steven Griffin, and for Gulf's General Counsel, Jeffery A. Stone.

CHAIRMAN BROWN: Thank you.

FIPUG.

MR. MOYLE: Thank you, Madam Chairman.

Jon Moyle on behalf of the Florida Industrial Power Users Group. I would also like to enter an appearance for Karen Putnal, and those would be in the 01, 02 and 07 dockets.

CHAIRMAN BROWN: Thank you.

Ms. Keating.

MS. KEATING: Thank you, Madam Chairman, Commissioners.

Beth Keating with the Gunster Law Firm here this afternoon for FPUC in the 01, 02, 03 and 04 dockets, for Indiantown and Chesapeake in the 04 docket, and for Florida City Gas in the 03 and 04 dockets.

CHAIRMAN BROWN: Okay. Thank you.

Mr. Cavros.

MR. CAVROS: Good afternoon, Madam Chair, Commissioners.

George Cavros on behalf of Southern Alliance for Clean Energy, entering an appearance in the 07 docket.

CHAIRMAN BROWN: Thank you.

Mr. Wright.

MR. WRIGHT: Robert Scheffel Wright and John T. Lavia, III, Gardner Law Firm, appearing on behalf of the Florida Retail Federation in the 01 docket, the fuel docket.

Thank you.

CHAIRMAN BROWN: Thank you.

Public Counsel.

MR. SAYLER: Erik Sayler on behalf of the Public Counsel. I would like to do a notice of appearance for Mr. Kelly, Ms. Christensen and myself in all the dockets but the 07 docket, and Mr. Rehwinkel.

MR. REHWINKEL: Yes, Charles Rehwinkel for the 07 docket only today, as well as Stephanie Morse.

Thank you.

CHAIRMAN BROWN: Thank you.

Staff.

MS. DUVAL: Margo DuVal for the 02 and 07 dockets. And I would like to enter appearances for Wesley Taylor in the 03 docket; Stephanie Cuello in the 04 and 07 dockets; Suzanne Brownless and Danijela Janjic in the 01 docket; and Charles Murphy in the 07 docket.

MS. HELTON: Mary Anne Helton as your adviser. I would also like to enter an appearance for your General Counsel, Keith Hetrick.

CHAIRMAN BROWN: Thank you.

Now, let's proceed with the 01 docket. We will open that up.

Whenever you --

MS. BROWNLESS: Yes, ma'am. The parties that are participating in the 01 docket are Duke Energy, Florida Power & Light, FPUC, Gulf, TECO, Office of Public Counsel, FIPUG, FRF and PCS Phosphate, unless Mr. Brew has indicated otherwise.

CHAIRMAN BROWN: He has been excused from this proceeding.

MS. BROWNLESS: Thank you.

CHAIRMAN BROWN: Let's go to the preliminary matters.

MS. BROWNLESS: Yes, ma'am. There are two preliminary matters. We wish to note that the following issues are contested in this docket: Issues 1A, 2A, 4A and 5A, which we refer to as the hedging issues, and issues 2J through 2P, which we refer to as the FP&L SoBRA issues. All other issues are Type 2 stipulations and can be voted upon today.

CHAIRMAN BROWN: Okay. Thank you.

Are there any other preliminary matters that need to be addressed at this time by the parties?

Seeing none, let's go to the record.

MS. BROWNLESS: Yes, ma'am.

The prefiled testimony of Duke's witnesses, Christopher Menendez, Joseph McCallister, Matthew J. Jones, as well as FP&L's witnesses, Renee Deaton, Gerard Yupp, Michael Kiley, Charles Rote, Liz Fuentes, Tiffany Cohen; FPUC's witnesses, Curtis Young, Michael Cassel, Mark Cutshaw; Gulf's witnesses, Shane Boyett, Cody Nicholson; TECO's witnesses, Penelope Rusk, Brian Buckley, Benjamin Smith, Brent Caldwell; and staff's witnesses, Simon Ojada, Donna Brown, George Simmons and Intesar Terkawi have all been stipulated to by all the parties.

And so at this time, we would ask that all of this testimony be inserted into the record as though read.

CHAIRMAN BROWN: Okay. Seeing no objection from any of the parties here today, we will go ahead and insert into the record as though read all of those witnesses you have just listed off.

MS. BROWNLESS: Thank you, ma'am.

(Whereupon, prefiled testimony was inserted.)

(Transcript continues in sequence in Volume 2.)

DUKE ENERGY FLORIDA

DOCKET NO. 170001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January through December, 2016

DIRECT TESTIMONY OF
Christopher A. Menendez

March 1, 2017

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 Florida, 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, LLC ("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. In this capacity, I am responsible for DEF's Final True-Up, Actual/Estimated Projection and Projection Filings in the Fuel Clause, Capacity Cost Recovery Clause and Environmental Cost Recovery Clause.

Q. Please describe your educational background and professional experience.

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

Q. 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 2016 through December 2016, 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 2016, year-to-date; and Exhibit No. __(CAM-4T), a schedule outlining the 2016 capital structure and cost rates applied to capital projects. Exhibit No. __(CAM-4T) is included for informational purposes only, as DEF's 2016 Actual True-Up Filing does not include a capital return component. Schedules A1 through A9, and A12 for the year ended December 31, 2016, were previously filed with the Commission on January 19, 2017. Revised Schedules A1, A3 and A4 for the year ended December 31, 2016 were filed with the Commission on February 20, 2017.

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. The Company relies on the information included in this testimony in the conduct of its affairs.

Q. Would you please summarize your testimony?

A. Per Order No. PSC-16-0547-FOF-EI, the estimated 2016 fuel adjustment true-up amount was an under-recovery of $26.2 million. The actual under-recovery for 2016 was $85.1 million resulting in a final fuel adjustment true-up under-recovery amount of $58.9 million. Exhibit No. __(CAM-1T).

The estimated 2016 capacity cost recovery true-up amount was an over-recovery of $14.7 million. The actual amount for 2016 was an over-recovery of $16.9 million resulting in a final capacity true-up over-recovery amount of $2.2 million. Exhibit No. __(CAM-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2016 for fuel cost recovery?

A. The actual ending balance as of December 31, 2016 for true-up purposes is an under-recovery of $85,111,174.

Q. How does this amount compare to DEF's estimated 2016 ending balance included in the Company's actual/estimated true-up filing?

A. The actual true-up amount attributable to the January - December 2016 period is an under-recovery of $85,111,174 which is $58,893,512 higher than the re-projected year end under-recovery balance of $26,217,663.

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 $85,111,174 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 unfavorable to the forecast by $43.3 million, while jurisdictional fuel and purchased power expense increased $41.9 million, resulting in a difference in jurisdictional fuel revenue and expense of $85.2 million. The $43.3 million decrease in jurisdictional fuel revenues is primarily attributable to the Final 2015 True-Up, which was an over-recovery of $37.8 million. In DEF's 2016 Midcourse Correction, DEF included this over-recovery in the calculation of the Midcourse adjustment; thereby returning the over-recovery to customers beginning in April 2016, as approved in Order No. PSC-16-0120-PCO-EI. As a result, DEF's actual revenues are lower than estimated revenues by $37.8 million. The $41.9 million increase in jurisdictional fuel and purchased power expense is primarily attributable to a unfavorable system variance from projected fuel and net purchased power of $96.9 million as more fully described below, partially offset by the 2013 Revised and Restated Stipulation and Settlement Agreement ("RRSSA") refunds. The RRSSA refunds are also discussed more fully below. The $85.1 million under-recovery also includes the deferral of $25,816 of 2015 under-recovery approved in Order No. PSC-16-0547-FOF-EI. The net result of the difference in jurisdictional fuel revenues and expenses of $85.2 million, minus the 2015 deferral of $25,821 and plus the 2016 interest provision calculated on the deferred balance throughout the year, is an under-recovery of $85.1 million as of December 31, 2016.

Q. Please explain the components contributing to the $58.9 million variance between the actual under-recovery of $85.1 million and the approved, estimated/actual under-recovery of $26.2 million.

A. The major factors contributing to the $58.9 million variance are a $80.7 million increase in system fuel and net power costs partially offset by a $16.6 million increase in revenues.

Q. Please explain the components shown on Exhibit No. __(CAM-1T), sheet 6 of 7, which helps to explain the $41.9 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 $96.9 million unfavorable system variance is mainly attributable to higher than expected firm purchases and increased system net generation. The $96.9 million variance is partially offset by the RRSSA refunds, which are discussed more fully below.

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.

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

A. Yes. DEF included an adjustment of approximately $1 million to coal inventory attributable to the semi-annual aerial surveys conducted on April 26, 2016 and November 10, 2016 in accordance with Docket No. 970001-EI, Order No. PSC-97-0359-FOF-EI. This adjustment represents 0.28% of the total coal consumed at the Crystal River facility in 2016.

Q. Were there any impacts to the 2016 True-up filing associated with the 2013 RRSSA?

A. Yes. Paragraphs 6.a and 6.b impact the 2016 true-up. Paragraph 6.a requires DEF to refund Residential and General Service Non-Demand customers $10 million in 2016 through the Fuel Adjustment Clause, allocated 94% to Residential and 6% to General Service Non-Demand. Paragraph 6.b requires DEF to refund Retail customers $60 million in 2016 through the Fuel Adjustment Clause. These impacts are addressed further in my 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. The 2016 Projection Filing, approved by the Commission in Order PSC-15-0586-FOF-EI, established the refund of $10 million through a reduction in 2016 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 2016 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 final true-up amount?

A. Exhibit No. ___ (CAM-1T) (Sheets 2 and 3 of 7) shows the refund of $60 million on line C.1a allocated evenly over the 12-month period. This amount is included in the 2016 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. On May 25, 2016, an outage occurred at the Hines Combined Cycle Plant. Did DEF incur any replacement power costs as a result of this outage?

A. Yes. DEF incurred retail replacement power costs of approximately $8.3 million ($8.4 million system). In December 2016, DEF chose to reduce retail fuel expense by $8.3 million to remove the impact of the replacement power to retail customers. This adjustment is included in Exhibit No. __(CAM-3T) in the footnote to line 6b on page 1 of 2, Schedule A2.

Q. Did DEF exceed the economy sales threshold in 2016?

A. No. DEF did not exceed the gain on economy sales threshold of $2.9 million in 2016. As reported on Schedule A1-2, Line 15a, the gain for the year-to-date period through December 2016 was $0.8 million. This entire amount was returned to customers through a reduction of total fuel and net purchased power expense recovered through the fuel clause.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November 2016 hearings been updated to incorporate actual data for all of year 2016?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2014 through 2016, as follows:

Year	Actual Gain
2014	$4,493,609
2015	$3,720,655
2016	$ 843,842
Three-Year Average	$3,019,369

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2016 for capacity cost recovery?

A. The actual ending balance as of December 31, 2016 for true-up purposes is an over-recovery of $16,868,290.

Q. How does this amount compare to the estimated 2016 ending balance included in the Company's actual/estimated true-up filing?

A. When the estimated 2016 over-recovery of $14,665,232 is compared to the $16,868,290 actual over-recovery, the final capacity true-up for the twelve month period ended December 2016 is an over-recovery of $2,203,058.

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 over-recovery of $2.2 million?

A. Exhibit No. __(CAM-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $2.2 million over-recovery is primarily due to higher than estimated sales.

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

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20170001-EI

Fuel and Capacity Cost Recovery
Actual/Estimated True-Up Amounts
January through December 2017

DIRECT TESTIMONY OF
Christopher A. Menendez

July 27, 2017

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. 20170001-EI?

A. Yes. I provided direct testimony on March 1, 2017.

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 the actual/estimated fuel and capacity cost recovery true-up amounts of Duke Energy Florida, LLC ("DEF" or the "Company") for the period of January through December 2017.

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 2017 actual/estimated 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-16-0001-PCO-EI. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2017 actual/estimated capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2017 and estimated data from July through December 2017.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2017 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is an under-recovery of $195,503,774. The calculation begins with the actual under-recovered balance of $184,422,095 taken from Schedule A2, page 2 of 2, line 13, for the month of June 2017. This balance plus the estimated July through December 2017 monthly true-up calculations comprise the estimated $195,509,774 under-recovered balance at year-end. The projected December 2017 true-up balance includes interest which is estimated from July through December 2017 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.085% per month.

Q. How does the current forecast of fuel costs on Schedule E3 for July through December 2017 compare with the same period forecast used in the Company's 2017 projection filing approved in Order No. PSC-16-0547-FOF-EI?

A. Coal costs increased \$0.28/mmbtu (10%) and light oil decreased \$1.00/mmbtu (4%). While natural gas costs were higher during the second half of 2016 and first half of 2017, the current forecast of natural gas costs, for July through December 2017, are slightly lower, \$0.05/mmbtu (1%), than those in DEF's 2017 Projection Filing approved in Order No. PSC-16-0547-FOF-EI.

Q. On February 9, 2017, an outage occurred at the Bartow Combined Cycle Plant. Has DEF included replacement power costs resulting from this outage in the 2017 actual/estimated true-up filing?

A. No. Consistent with the Stipulation filed June 14, 2017 in the instant docket, DEF has not included replacement power costs resulting from this outage. These costs will remain in the over/under account to be considered in Docket No. 20180001-EI for recovery in 2019 rates subject to normal intervener challenge and Commission reasonableness and prudence review and approval.

Q. Have any adjustments been made to estimated fuel costs for the period July through December 2017?

A. Yes. Consistent with the Stipulation filed on June 14, 2017 in the instant docket, DEF included an adjustment of $10,973,639 (grossed up to $11,038,768 from retail to system). This adjustment is included on Schedule E1-B (sheet 2), line A5, column Jul Estimated.

Q. Does DEF expect to exceed the three-year rolling average gain on non-separated power sales in 2017?

A. No. DEF estimates the total gain on non-separated sales during 2016 will be $748,832, which does not exceed the three-year rolling average of $3,019,369.

CAPACITY COST RECOVERY

Q. What is DEF's 2017 estimated capacity true-up balance and how was it developed?

A. DEF's estimated capacity true-up balance is an under-recovery of $5,121,339. The estimated true-up calculation begins with the actual under-recovered balance of $7,299,099 for the month of June 2017. This balance plus the estimated July through December 2017 monthly true-up calculations comprise the estimated $5,121,339 under-recovered balance at year-end. The projected December 2017 true-up balance includes interest which is estimated from July through December 2017 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.085% per month.

Q. What are the primary drivers of the estimated year-end 2017 capacity under-recovery?

A. The $5.1 million under-recovery is primarily attributable to lower than projected capacity revenues of approximately $9.2 million offset by approximately $1.9 million lower capacity costs and approximately $2.2 million prior period true up over-recovery balance.

Q. Has DEF included the nuclear cost recovery amounts approved in Order No. PSC-16-0547-FOF-EI?

A. Yes. DEF has included $51,700,333 of 2017 recoverable expenses associated with the CR-3 Uprate project.

Q: Has DEF included any servicing fees in excess of incremental cost related to the Asset Securitization Charge (ASC) in the CCR Filing.

A: Yes, DEF included $296,269 of excess servicing fees on Line 30 of Schedule E12-B, column EST Jul-17, which include approximately $793 of interest from March through June 2017. Order No. 15-0537-FOF-EI requires DEF to credit back to customers through the Capacity Cost Recovery Clause any excess servicing fees collected on the ASC.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20170001-EI

Fuel and Capacity Cost Recovery Factors
January through December 2018

DIRECT TESTIMONY OF
Christopher A. Menendez

August 24, 2017

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. 20170001-EI?

A. Yes, I provided direct testimony on March 1, 2017 and July 27, 2017.

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 2018.

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 as DEF is not requesting recovery for any capital projects 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 4.380 ¢/kWh. This factor consists of a fuel cost for the projection period of 3.8644 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.0072 ¢/kWh, and an estimated prior period under-recovery true-up of 0.5049 ¢/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 11-12 show the Company's proposed tiered rates of 4.091 ¢/kWh for the first 1,000 kWh and 5.091 ¢/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 1.236 On-peak and 0.890 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 2017 net true-up that DEF has included in the fuel cost recovery factor for 2018?

A. DEF has included a projected under-recovery of $195,503,774. This amount includes a projected actual/estimated under-recovery for 2017 of $136,610,259, and the final 2016 true-up net under-recovery of $58,893,515 as included in my Direct Testimony filed on March 1, 2017.

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 2018 of 4.385 ¢/kWh is an increase of 0.718 ¢/kWh or 20% from the 2017 levelized residential fuel factor of 3.667 ¢/kWh.

Q. Please explain the increase in the 2018 fuel factor compared with the 2017 fuel factor.

A. The primary drivers of the increase in the 2018 fuel factor are the increase in prior period true-up amount and increase in projected natural gas costs. The 2017 fuel factor included a $26 million under-recovery, whereas the 2018 fuel factor includes a $196 million under-recovery. This results in a net change of approximately $170 million or 0.438 ¢/kWh. Projected natural gas costs in 2018 are approximately $102 million or 0.263 ¢/kWh higher than 2017.

Q. Have you made any adjustments to your estimated fuel costs for the period January through December 2018?

A. No, DEF has made no adjustments for 2018.

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 71% of all residential energy is consumed in the first tier and 29% 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-2002-0655-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 4.385 ¢/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 2018 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2018 is estimated to be $983,516 which is below the benchmark of $1,771,110. 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-2000-1744-PAA-EI. Therefore, since the total gain on non-separated sales was below the benchmark, none of the gains will be retained for shareholders. The benchmark was calculated based on the average of actual gains for 2015 and 2016 of $3,720,655 and $843,842, respectively, and estimated gains for 2017 of $748,832 in accordance with Order No. PSC-2000-1744-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-1997-0262-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 30-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 are based on a combination of third party forecasts as well as hedges and/or forward contracts currently in place. 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. 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.

Q. Is the revised 2016 GPIF reward discussed in the August 24, 2017 direct testimony of Matt J. Jones included in 2018 rates?

A. Yes. The revised GPIF reward of $2,793,216 is included on Schedule E1, Line 26 of Exhibit CAM-3, Part 2.

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 2018</u>

Page 1 of Schedule E12-A includes estimated 2018 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, F.A.C. The retail portion of the capacity payments is calculated using separation factors consistent with DEF's 2013 RRSSA approved in Order No. PSC-2013-0598-

FOF-EI.

The revenue requirements for the CR3 Uprate Project are as stipulated by DEF and the intervener parties and approved by bench vote of the Commission on August 15, 2017, in Docket 20170009-EI. The recovery of estimated Dry Casket Storage costs, also referred to as Independent Spent Fuel Storage Installation ("ISFSI") costs, are included on line 37 of Schedule E12-A, page 1. Schedule E12-A, page 2, provides dates and MWs associated with the QF and purchase power contracts.

DEF has shown the 2018 Calculation of Projected Capacity Costs, which includes Levy related costs, on Schedule E-12A, line 40.

<u>Schedule E12-B – Calculation of Estimated/Actual True-Up - Year 2017</u>

Schedule E12-B, which is also included in Exhibit __(CAM-2) to my direct testimony filed on July 27, 2017, as part of the 2017 actual/estimated true-up filing, calculates the estimated true-up capacity under-recovered balance for calendar year 2017 of $5,121,339. This balance is carried forward to Schedule E12-A, line 30 to be collected from customers from January through December 2018.

<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. Schedule E12-D also includes the uniform percentage calculation and allocation of the ISFSI revenue requirement to the rate classes.

Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class

Schedule E12-E pages 1 calculates the CCR factors for capacity, CR3 Uprate and Levy 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 factor for ISFSI Dry Cask Storage in cents per kWh is calculated by dividing recoverable costs allocated on Schedule E12-D 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. ISFSI costs are allocated to rate classes by applying a uniform percent increase as approved in Order No. PSC-2016-0425-PAA-EI. 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 on Schedule E12-E page 2 in columns 13 – 19.

Pursuant to the Motion approved the Commission in Order No. PSC-2017-0260-PCO-EI, DEF has separately shown the 2018 calculation of Projected Capacity Costs, excluding Levy related costs, on Schedule E12-E, pages 3 and 4.

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 2018 projected average retail CCR factor?

A. The 2018 average retail CCR factor is 1.424 ¢/kWh, made up of capacity of 1.060 ¢/kWh, ISFSI costs of 0.024 ¢/kWh, CR3 Uprate costs of .0128 ¢/kWh, and Levy costs of 0.212 ¢/kWh. The 2018 average retail CCR factor without Levy is 1.212 ¢/kWh.

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 rate of 1.424 is 0.330 ¢/kWh, or 30%, higher than the 2017 factor of 1.094 ¢/kWh. This increase is primarily due to the inclusion of Levy-related costs in the 2018 factor and the difference in the prior period true-up balance.

Q. Does this conclude your testimony?

A. Yes

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20170001-EI

Alternative Fuel and Capacity Cost Recovery Factors
January through December 2018

DIRECT TESTIMONY OF
Christopher A. Menendez

September 1, 2017

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. 20170001-EI?

A. Yes, I provided direct testimony on March 1, 2017, July 27, 2017 and August 24, 2017.

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 alternative fuel and capacity cost recovery factors of Duke Energy Florida, LLC ("DEF" or the "Company") for the period of January through December 2018.

The alternative fuel and capacity cost recovery factors include revisions set forth in the 2017 Second Revised and Restated Stipulation and Settlement Agreement ("2017 Agreement") filed on August 29, 2017 in Docket No. 20170183-EI.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Alternative 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 as DEF is not requesting recovery for any capital projects in this docket. Part 3 contains capacity cost recovery (CCR) schedules.

FUEL COST RECOVERY CLAUSE

Q. Please describe the alternative 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 4.127 ¢/kWh. This factor consists of a fuel cost for the projection period of 3.8644 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.0072 ¢/kWh, and an estimated prior period under-recovery true-up of 0.2524 ¢/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 11-12 show the Company's proposed tiered rates of 3.838 ¢/kWh for the first 1,000 kWh and 4.838 ¢/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 1.236 On-peak and 0.890 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 total 2017 net true-up?

A: The total net true-up under-recovery for 2017 is $195,503,774. This amount includes a projected actual/estimated under-recovery for 2017 of $136,610,259, and final 2016 true-up net under-recovery of $58,893,515 as included in my Direct Testimony filed on March 1, 2017.

Q. What amount of the total 2017 net true-up has DEF included in the fuel cost recovery factor for 2018?

A. Pursuant to the 2017 Agreement, DEF will recover the total 2017 net true-up over 2018 and 2019. As shown on Line 5 of Schedule E1-A in Exhibit CAM-3, Part 2, DEF has included an under-recovery of $97,751,887 for recovery in 2018 rates.

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 2018 of 4.132 ¢/kWh is an increase of 0.465 ¢/kWh or 13% from the 2017 levelized residential fuel factor of 3.667 ¢/kWh.

Q. Please explain the increase in the 2018 fuel factor compared with the 2017 fuel factor.

A. The primary drivers of the increase in the 2018 fuel factor is the increase in prior period true-up amount, and increase in projected natural gas costs. The 2017 fuel factor included a $26 million under-recovery, whereas the 2018 fuel factor includes a $98 million under-recovery; this results in a net change of approximately $72 million or 0.186 ¢/kWh. Projected natural gas costs in 2018 are approximately $102 million or 0.263 ¢/kWh higher than 2017.

Q. Have you made any adjustments to your estimated fuel costs for the period January through December 2018?

A. No, DEF has made no adjustments for 2018.

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 71% of all residential energy is consumed in the first tier and 29% 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-2002-0655-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 4.132 ¢/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 2018 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2018 is estimated to be $983,516 which is below the benchmark of $1,771,110. 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-2000-1744-PAA-EI. Therefore, since the total gain on non-separated sales was below the benchmark, none of the gains will be retained for shareholders. The benchmark was calculated based on the average of actual gains for 2015 and 2016 of $3,720,655 and $843,842, respectively, and estimated gains for 2017 of $748,832 in accordance with Order No. PSC-2000-1744-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-1997-0262-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 30-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 are based on a combination of third party forecasts as well as hedges and/or forward contracts currently in place. 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. Consistent with past practices, DEF will continue to monitor fuel prices and update the projection filing prior to the October hearing if changes in fuel prices warrant such an update.

Q. Is the revised 2016 GPIF reward discussed in the August 24, 2017 direct testimony of Matt J. Jones included in 2018 rates?

A. Yes. The revised GPIF reward of $2,793,216 is included on Schedule E1 of Alternative Exhibit CAM-3, Part 2, Line 26.

CAPACITY COST RECOVERY CLAUSE

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

A. The following schedules are included in my exhibit:

<u>Schedule E12-A – Calculation of Projected Capacity Costs – Year 2018</u>

Page 1 of Schedule E12-A includes estimated 2018 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, F.A.C. The retail portion of the capacity payments is calculated using separation factors consistent with DEF's 2013 RRSSA approved in Order No. PSC-2013-0598-FOF-EI, which were carried over unchanged into the 2017 Agreement.

The revenue requirements for the CR3 Uprate Project are as stipulated by DEF and the intervener parties and approved by bench vote of the FPSC on August 15, 2017, in Docket 20170009-EI. The recovery of estimated Dry Cask Storage costs, also referred to as Independent Spent Fuel Storage Installation ("ISFSI") costs, are included on line 37 of Schedule E12-A, page 1. Schedule E12-A, page 2, provides dates and MWs associated with the QF and purchase power contracts.

Pursuant to the 2017 Agreement, DEF has removed all Levy costs from the Alternative 2018 Capacity Clause Projection Filing and has not included any Levy costs in the calculation of 2018 rates.

Schedule E12-B – Calculation of Estimated/Actual True-Up - Year 2017

Schedule E12-B, which is also included in Exhibit __(CAM-2) to my direct testimony filed on July 27, 2017 in the 2017 actual/estimated true-up filing, calculates the estimated true-up capacity under-recovered balance for calendar year 2017 of $5,121,339. This balance is carried forward to Schedule E12-A, line 30 to be collected from customers from January through December 2018.

Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class

Schedule E12-D is the calculation of the 12CP and 1/13 average demand allocators for each rate class. Schedule E12-D also includes the uniform percentage calculation and allocation of the ISFSI revenue requirement to the rate classes.

Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class

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 and CR3 Uprate 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 factor for ISFSI Dry Cask Storage in cents per kWh is calculated by dividing recoverable costs allocated on Schedule E12-D 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 and CR3 Uprate costs to rate classes in the same manner in which they would be allocated if they were recovered in base rates. ISFSI costs are allocated to rate classes by applying a uniform percent increase as approved in Order No. PSC-2016-0425-PAA-EI.

Pursuant to the 2013 RRSSA and carried over in the 2017 Agreement, 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 13 – 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 2018 projected average retail CCR factor?

A. The 2018 average retail CCR factor is 1.212 ¢/kWh, made up of capacity of 1.060 ¢/kWh, ISFSI of 0.024 ¢/kWh and CR3 Uprate costs of 0.128 ¢/kWh.

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 1.212 ¢/kWh is 0.118 ¢/kWh, or 11%, higher than the 2017 factor of 1.094 ¢/kWh, approved in Order No. PSC-2016-0547-FOF-EI. This increase is primarily attributable to the difference in prior-period true-up balance.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA
DOCKET NO. 170001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December 2016

DIRECT TESTIMONY OF
JOSEPH MCCALLISTER

April 3, 2017

Q. Please state your name and business address.

A. My name is Joseph McCallister. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I work for Duke Energy Progress, an affiliate company of Duke Energy Florida, LLC ("DEF" or "Company") as the Director of Natural Gas, Oil and Emissions. I am responsible for the natural gas, fuel oil and emission group activities in the Fuel Procurement Section of the Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for the natural gas and fuel oil acquisition and transportation needed to support the generation needs for Duke Energy Indiana ("DEI"), Duke Energy Kentucky ("DEK"), Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP"), and DEF. In addition, this group is responsible for the emission allowance ("EA") position management for DEI, DEK, DEC, DEP and DEF.

Q. Have you testified before the Commission in previous fuel clause proceedings?

A. Yes.

Q. Please briefly describe your work experience.

A. I received a Bachelor Degree in Business Administration majoring in Accounting from The Ohio State University. While at Duke Energy, from 2003 until mid 2006, I served as the Director of Portfolio and Market Risk Assessment through mid 2006, the Director of Gas and Oil Trading from mid 2006 through early 2009, the Director of Gas, Oil and Power from early 2009 to June 2012, and Director of Natural Gas, Oil and Emissions from July 2012 to the present. Prior to my tenure with Duke Energy, I spent approximately 10 years in management positions at energy trading and asset generation based companies. Summary experiences over this time period include gas and power scheduling, real time power trading and scheduling management, commercial management of gas storage and transportation agreements, commercial management of fuel and power optimization activities for unregulated generation assets and wholesale contract agreements, and corporate planning. The Company relies on information contained in my testimony and exhibits when conducting its affairs.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the August through December 2016 hedging true-up data and summarize the results of DEF's hedging activity for calendar year 2016 as required by Commission Order No. PSC-02-1484-FOF-EI and further clarified by Commission Order No. PSC-08-0667-PPA-EI issued in October 2008, and Commission Order No. PSC-09-0255-PAA-EI issued in April 2009.

Q. Have you prepared exhibits to your testimony?

A. Yes. I have attached Exhibit No.___ (JM-1T) which is the Hedging Activity Report for the period August through December 2016.

Q. What are the objectives of DEF's hedging strategy?

A. The objectives of DEF's hedging program to reduce fuel price volatility risk and provide greater cost certainty for DEF's customers.

Q. What hedging activities did DEF undertake for 2016 and what were the results?

A. As outlined in DEF's 2016 Risk Management Plan, DEF utilized approved financial agreements to hedge a portion of its projected natural gas and a portion of the estimated fuel surcharge exposure embedded in DEF's coal river barge transportation agreements. These activities resulted in a net hedge cost for 2016 of approximately $150.0 million.

REDACTED

Q. Did DEF execute its hedging activities consistent with its approved Risk Management Plan?

A. Yes. The financial hedging activities executed by DEF were consistent with those outlined in its 2016 Risk Management Plan ("Plan"). In the Plan filed in August 2015, DEF's hedging target ranges were to hedge [redacted] to [redacted] of its forecasted natural gas burns for calendar year 2016 with a target to hedge a minimum of [redacted] of the forecasted natural gas burns over time. With respect to the coal river transportation estimated fuel surcharge exposures for calendar year 2016, DEF targeted to hedge between [redacted] to [redacted] of the estimated fuel surcharge exposures based on contractual provisions in the coal river barge transportation agreements.

For 2016, DEF's hedge percentages based on actual burns for natural gas was approximately [redacted]. DEF hedge percentages for the estimated fuel surcharges embedded in DEF's coal river transportation in 2016 was approximately [redacted]. The actual hedge percentages for natural gas and the estimated fuel surcharges for coal river transportation were within the ranges outlined in the Plan. As outlined in the Plan, actual hedge percentages for any monthly period, rolling twelve month time period or calendar annual period can come in higher or lower than the hedge percentage targets as a result of actual versus forecasted fuel burns.

Q. Did DEF hedging activities meet the stated objective and are the activities consistent with the Commission's Orders for hedging?

A. Yes. DEF's hedging activity met the stated objective of DEF's hedging program to reduce price risk and provide greater cost certainty for DEF's customers. The hedging activities are consistent with Commission Orders No. PSC-02-1484-FOF-EI, No. PSC-08-0667-PPA-EI, and No. PSC-09-0255-PAA-EI. DEF's hedging activities are conducted in an environment of strong internal controls and executed in a structured manner. DEF's hedging activities do not attempt to outguess the market and may or may not result in net fuel cost savings, but have achieved the objectives of reduced fuel price volatility.

Q. Does this conclude your testimony?

A. Yes.

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA, LLC. FOR

FUEL AND CAPACITY COST RECOVERY FINAL TRUE-UP FOR THE PERIOD JANUARY THROUGH JULY 2017

FPSC DOCKET NO. 20170001-EI

DIRECT TESTIMONY OF Joseph McCallister

August 18, 2017

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Joseph McCallister. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I work for Duke Energy Progress, LLC, an affiliate company of Duke Energy Florida, LLC (“DEF”, “Petitioner” or “Company”), as the Director, Natural Gas Oil and Emissions. I am responsible for the natural gas, fuel oil and emission group activities in the Fuel Procurement Section of the Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for the natural gas and fuel oil acquisition and transportation needed to support the generation needs for Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida. In addition, this group is responsible for the emission allowance (“EA”) position management for Duke

Energy Indiana, Duke Energy Kentucky, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida.

Q. Please describe your education background and professional experience.

A. I received a Bachelor Degree in Business Administration majoring in Accounting from The Ohio State University. While at Duke Energy, from 2003 until mid-2006, I served as the Director of Portfolio and Market Risk Assessment through mid-2006, the Director of Gas and Oil Trading from mid-2006 through early 2009, the Director of Gas, Oil and Power from early 2009 to June 2012, and Director of Gas, Oil and Emissions from July 2012 to the present. Prior to my tenure with Duke Energy, I spent approximately 10 years in management positions at energy trading and asset generation based companies. Summary experiences over this time period include gas and power scheduling, real time power trading and scheduling management, commercial management of gas storage and transportation agreements, commercial management of fuel and power optimization activities for unregulated generation assets and wholesale contract agreements, and corporate planning.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to outline DEF's hedging results for January 2017 through July 2017.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibit:

- Exhibit No.___ (JM-1P) – Hedging Results for January 2017 through July 2017 (*filed August 18, 2017*).

Q. What are the objectives of DEF's hedging activities?

A. The objectives of DEF's hedging strategy are to reduce the impacts of fuel price risk and volatility over time, and provide a greater degree of fuel price certainty for DEF's customers for a portion of fuel costs.

REDACTED

Q. Describe DEF's hedging activities that the Company has executed for 2018.

A. As approved by the Commission, DEF is currently under a moratorium on hedging pending Commission review in Docket 20170057-EI and has not executed any financial hedges for any periods since October 21, 2016. As of July 31, 2017, DEF had hedges in place for approximately [redacted] percent of its current forecasted natural gas burns for 2018 pursuant to its Commission-approved 2015 Risk Management Plan. Please note, the current forecasted percentage of natural gas burns hedged could vary over time based on actual versus projected burns.

Q. What were the results of DEF's hedging activities for January through July 2017?

A. The Company's natural gas hedging activities for the period of January 2017 through July 2017 have resulted in hedges being above the closing natural gas settlement prices by approximately $18.7 million**.** With respect to coal river transportation estimated fuel surcharge exposures, DEF will no longer execute financial hedge transactions for periods after 2016. DEF's hedging activity did achieve the objective to reduce the impacts of fuel price risk and volatility, and providing greater fuel price certainty for DEF's customers.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 170001-EI

**GPIF Schedules for
January through December 2016**

DIRECT TESTIMONY OF MATTHEW J. JONES

March 15, 2017

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 Carolinas, LLC ("DEC") as Managing Director of Analytics for Fuels and Systems Optimization. DEC is a corporate affiliate of Duke Energy Florida ("DEF" or the "Company"), both of which are wholly-owned subsidiaries of Duke Energy Corporation ("Duke Energy").

Q. Describe your responsibilities as Managing 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's regulated utility subsidiaries, including DEF, DEC, Duke Energy Indiana LLC, 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 Generating Performance Incentive Factor ("GPIF") reward/(penalty) amount for the period of January through December 2016. This calculation was based on a comparison of the actual performance of DEF's Seven (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 reward of $3,639,706. 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 primarily concern 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.

In addition, the Bartow combined cycle ("CC") unit had data excluded during the March through June steam turbine planned-outage extension period. The Bartow CC unit has the capability to operate in simple cycle mode while the steam turbine is in an outage; when operating in simple cycle mode, the unit's heat rate deviates significantly from its normal range. To account for the heat-rate deviation that occurs when Bartow operates in simple cycle mode, DEF's heat rate target setting process for the Bartow CC unit excludes historical data from periods when the unit operated in simple cycle mode. To be consistent with the target setting process, the simple cycle mode heat rate data was excluded from actuals for the purposes of calculating the 2016 heat rate for the Bartow CC unit.

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 2016

FPSC DOCKET NO. 20170001-EI

GPIF TARGETS AND RANGES FOR
JANUARY THROUGH DECEMBER 2018

DIRECT TESTIMONY OF
MATTHEW J. JONES

August 24, 2017

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 Corporation ("Duke Energy") as Managing Director of Analytics for Fuels and Systems Optimization. Duke Energy Florida, LLC ("DEF" or "Company") is a wholly-owned subsidiary of Duke Energy.

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's regulated utility subsidiaries, including DEF, as well as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Duke Energy Indiana LLC, 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. 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 2016 and also present the development of the Company's Generating Performance Incentive Factor ("GPIF") targets and ranges for the period January through December 2018. 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 and reported in your March 15, 2017 testimony for the period January through December 2016?

A. DEF's originally calculated GPIF incentive amount for this period was a reward of $3,639,706. Please refer to my testimony filed March 15, 2017 for the details of how this incentive amount was calculated.

Q. Have there been any adjustments to the incentive amount filed in March?

A. Yes. A revision to the amount of gas consumed at the Hines station was recently identified. This resulted in Hines station's heat rate initially being calculated to be more favorable than it actually was. When the revisions to gas consumption and resulting heat rate were incorporated into the 2016 incentive calculation, the reward was reduced to $2,793,216, a reduction of $846,490.

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.

I have also included a revised Exhibit No. __ (MJJ-1T) to replace the exhibit filed with my March 15, 2017 testimony, as discussed above.

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

A. For the 2018 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 88% of the estimated total system net generation for the period, excluding Osprey CC and Citrus CC units 1 and 2 as explained below.

Osprey CC and Citrus CC Units 1 and 2 were not included for the upcoming projection period since there is insufficient performance history to use in setting targets and ranges for these units.

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 EUOF and planned outage factor ("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 historical performance?

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 2017?

A. The estimated maximum incentive for the Company is $22,480,036. 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

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 170001-EI

MARCH 1, 2017

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. 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. Please state your education and business experience.

A. I hold a Bachelor of Science in Business Administration and a Master of Business Administration from Charleston Southern University. Since joining FPL in 1998, I have held various positions in the rates and regulatory areas. Prior to my current position, I held the positions of Senior Manager of Cost of Service and Load Research and Senior Manager of Rate Design in the Rates and Tariffs Department. I have previously testified before this Commission in base rate and clause recovery proceedings. I am a member of the Edison Electric Institute ("EEI") Rates and Regulatory Affairs Committee, and I have completed the EEI Advanced Rate Design Course. I have been a guest speaker at Public Utility Research Center/World Bank International Training Programs on Utility Regulation and Strategy. In 2016, I assumed my current position as Director, Cost Recovery Clauses, where I am responsible for providing direction as to appropriateness of inclusion of costs through a cost recovery clause and the overall preparation and filing of all cost recovery clause documents including testimony and discovery.

Q. What is the purpose of your testimony 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 2016 through December 2016.

The net true-up for the FCR is an under-recovery, including interest, of $28,780,519. FPL is requesting Commission approval to include this FCR true-up under-recovery of $28,780,519 in the calculation of the FCR factor for the period January 2018 through December 2018.

The net true-up for the CCR is an over-recovery, including interest, of $7,586,581. FPL is requesting Commission approval to include this CCR true-up over-recovery of $7,586,581 in the calculation of the CCR factors for the period January 2018 through December 2018.

Finally, FPL is requesting Commission approval to include $10,101,485 in the calculation of the FCR factors for the period January 2018 through December 2018, which represents FPL's share of the 2016 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 2016 through December 2016 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 2016 through December 2016, an under-recovery of $28,780,519.

The summary of the net true-up amount shows the actual end-of-period true-up under-recovery for the period January 2016 through December 2016 of $55,264,203 on line 1. The actual/estimated true-up under-recovery for the same period of $26,483,684 is shown on line 2. Line 1 less line 2 results in the net final true-up for the period January 2016 through December 2016 of $28,780,519 under-recovery shown 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 2016 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 2016 through December 2016.

Q. Have you provided schedules showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2016?

A. Yes. Appendix I, page 3, compares the actual end-of-period true-up under-recovery of $47,690,279 to the actual/estimated end-of-period true-up under-recovery of $18,909,760 resulting in a net under-recovery of $28,780,519. Appendix I, page 3 lines 42 and 33, shows that the variance consists of an increase in jurisdictional costs of $59.3 million partially offset by an increase in revenues of $30.5 million.

Q. 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 an increase of $61,637,278. This increase was primarily due to a $69.0 million increase in Fuel Cost of System Net Generation resulting from an increase in consumption of $81.2 million partially offset by a $12.1 million reduction in fuel price. The remaining variance is due to a $5.5 million increase in Energy Payments to Qualifying Facilities ("QFs"), a $2.6 million increase in Energy Cost of Economy Purchases, and a $0.5 million increase in Variable Power Plant O&M Costs over 514,000 MWh Threshold. These amounts were partially offset by a $5.0 million increase in Gains from Off-System Sales, a $4.9 million increase in Fuel Cost of Power Sold, a $4.3 million decrease in Non Recoverable Oil/Tank Bottoms, a $1.5 million decrease in Fuel Cost of Purchased Power, and a $0.2 million decrease in Scherer Coal Cars Depreciation & Return.

<u>Fuel Cost of System Net Generation - $69.0 million increase (Appendix I, page 3, line 2)</u>

The table below provides the detail of this variance.

Fuel Variance	**2016 FINAL TRUE-UP**	**2016 ACTUAL/ ESTIMATED**	**DIFFERENCE**
<u>Heavy Oil</u>			
Total Dollar	$69,082,497	$54,254,515	$14,827,982
Units (MMBTU)	4,886,936	3,872,764	1,014,171
$ per Units	14.1362	14.0092	0.1269
Variance Due to Consumption			$14,207,779
Variance Due to Cost			$620,203
Total Variance			$14,827,982
<u>Light Oil</u>			
Total Dollar	$35,199,998	$29,855,078	$5,344,921
Units (MMBTU)	2,351,473	2,028,887	322,585
$ per Units	14.9693	14.7150	0.2543
Variance Due to Consumption			$4,746,845
Variance Due to Cost			$598,076
Total Variance			$5,344,921
<u>Coal</u>			
Total Dollar	$125,957,742	$122,755,659	$3,202,082

Fuel Variance	2016 FINAL TRUE-UP	2016 ACTUAL/ ESTIMATED	DIFFERENCE
Units (MMBTU)	45,628,322	45,192,067	436,255
$ per Units	2.7605	2.7163	0.0442
Variance Due to Consumption			$1,185,003
Variance Due to Cost			$2,017,079
Total Variance			$3,202,082
Gas			
Total Dollar	$2,432,079,359	$2,380,989,998	$51,089,361
Units (MMBTU)	624,091,790	607,164,211	16,927,580
$ per Units	3.8970	3.9215	(0.0245)
Variance Due to Consumption			$66,381,379
Variance Due to Cost			($15,292,019)
Total Variance			$51,089,361
Nuclear			
Total Dollar	$198,341,685	$203,733,327	($5,391,641)
Units (MMBTU)	309,677,643	317,993,383	(8,315,740)
$ per Units	0.6405	0.6407	(0.0002)
Variance Due to Consumption			($5,327,763)
Variance Due to Cost			($63,878)
Total Variance			($5,391,641)
Total			
Variance Due to Consumption			$81,193,243
Variance Due to Cost			($12,120,531)
Total Variance			$69,072,704

Note: Fuel Cost of System Net Generation reflected above does not tie to amounts provided on the 2016 Actual/Estimated or 2016 Final true-up schedules due to various adjustments that occurred in 2016. These adjustments were included and footnoted on the impacted monthly A-Schedule.

<u>Energy Payments to Qualifying Facilities - $5.5 million increase (Appendix I, page 3, line 8)</u>

The variance for Energy Payments to Qualifying Facilities is primarily attributable to higher than projected purchases and costs from the Indiantown Co-

Generation ("ICL") facility. In total, FPL purchased 60,903 MWh more than projected from ICL with an average unit fuel cost that was $7.13/MWh higher than projected. This combination of higher purchases and fuel costs from ICL resulted in a variance of $7.5 million increase. The variance attributable to ICL was partially offset by lower costs from the Broward South Firm Co-Generation facility and lower purchases and costs from As-Available Co-Generation facilities. The total variance from the Firm and As-Available Co-Generation facilities was $2.0 million decrease. The combination of the variance related to ICL and the variance related to the Firm and As-Available Co-Generation facilities resulted in a total variance for Energy Payments to Qualifying Facilities of $5.5 million increase.

<u>Energy Cost of Economy Purchases - $2.6 million increase (Appendix I, page 3, line 9)</u>

The variance for the Energy Cost of Economy Purchases is primarily attributable to higher than projected costs for economy purchases. The average cost of economy purchases was $1.90/MWh higher than projected, resulting in a cost variance of $3.7 million increase. This cost variance was partially offset by lower than projected economy purchases. FPL purchased 32,232 MWh less of economy power resulting in a volume variance of $1.1 million decrease. The combination of higher costs for economy purchases and lower volume of economy purchases resulted in a net variance of $2.6 million increase.

<u>Variable Power Plant O&M Costs over 514,000 MWh Threshold - $0.5 million increase (Appendix I, page 3, line 14)</u>

The variance for the Variable Power Plant O&M Costs over 514,000 MWh Threshold is attributable to higher than projected economy sales.

<u>Gains from Off-System Sales - $5.0 million increase (Appendix I, page 3, line 6)</u>

The variance for Gains from Off-System Sales is attributable to higher than projected economy sales coupled with higher than projected margins on economy sales. FPL sold 390,965 MWh more of economy power than projected, resulting in a variance of $2.8 million increase. In addition, the margin on economy sales averaged $0.86/MWh more than projected which resulted in a variance of $2.1 million increase. The combination of higher economy sales coupled with higher margins on economy sales resulted in a total variance for Gains from Off-System Sales of $5.0 million increase.

<u>Fuel Cost of Power Sold - $4.9 million increase (Appendix I, page 3, line 5)</u>

The variance for the Fuel Cost of Power Sold is primarily attributable to higher than projected economy sales. As discussed above, FPL sold 390,965 MWh more of economy power, resulting in a volume variance on economy sales of $7.3 million increase. This volume variance was partially offset by lower than projected fuel costs attributable to economy sales. The average unit fuel cost on economy power sales was $0.86/MWh lower than projected, resulting in a cost variance of $2.1 million decrease. The combination of higher economy power sales and lower fuel costs attributable to economy sales resulted in a net variance of $5.2 million increase, which is partially offset by a variance of $0.3 million decrease attributable to the net of lower than projected St. Lucie Plant Reliability Exchange sales and by lower than projected fuel costs on St. Lucie Plant Reliability Exchange sales.

<u>Non-Recoverable Tank Bottoms - $4.3 million decrease (Appendix I, page 3, line 22)</u>

The variance for Non-Recoverable Tank Bottoms is primarily related to tanks taken out of service at the Turkey Point Plant, Lauderdale Plant and Port Everglades Plant.

<u>Fuel Cost of Purchased Power - $1.5 million decrease (Appendix I, page 3, line 7)</u>

The variance for the Fuel Cost of Purchased Power is primarily attributable to lower than projected purchases and costs under FPL's two Solid Waste Authority ("SWA") contracts. In total, FPL purchased 76,055 MWh less than projected from SWA. The unit fuel cost under one contract averaged $6.05/MWh less than projected and the unit fuel cost under the second contract averaged $0.53/MWh less than projected. The combination of lower purchases and lower fuel costs resulted in a total variance for SWA purchases of $4.6 million decrease. This variance was partially offset by higher purchases and slightly higher fuel costs from St. John's River Power Park ("SJRPP") that resulted in a total variance for SJRPP of $2.9 million increase. The remaining variance of $0.3 million increase was primarily attributable to higher than projected purchases under the St. Lucie Reliability Exchange.

Scherer Coal Cars Depreciation & Return - $0.2 million decrease (Appendix I, page 3, line 3)

The variance for Scherer Coal Cars Depreciation & Return is related to insurance proceeds for damaged cars as a result of an accident.

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

A. As shown on Appendix I, page 3, line 33, actual jurisdictional FCR revenues, net of revenue taxes, were approximately $30.5 million higher than the actual/estimated projection. This was primarily due to jurisdictional sales that were 1,045,622 MWh higher than the actual/estimated projection.

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $10,101,485 as its 60% share of 2016 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 2016 Incentive Mechanism gains through the 2018 FCR factors, consistent with prior years. FPL will include the approved jurisdictionalized Incentive Mechanism amount in the calculation of the 2018 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 2018 through December 2018 as a reduction to jurisdictional fuel revenues applicable to each period.

Q. Does FPL's 2016 FCR net true-up amount include the true-up to the refund for removal of Woodford gas reserve expenses?

A. Yes. As explained in the testimony of FPL witness Yupp, the true-up of $126,520 related to the Woodford refund is part of FPL's 2016 FCR net true-up amount and will be included in FPL's 2018 FCR factors. This amount represents the difference between the actual true-up amount of $1,631,772 related to Woodford for July 2016 through December 2016 and the refund amount of $1,505,252 for the same time period that was included in FPL's 2016 Actual/Estimated filing. The calculation of this final true-up amount is shown on Page 3 of Exhibit GJY-1.

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 2016 through December 2016, an over-recovery of $7,586,581, which FPL is requesting to be included in the calculation of the CCR factors for the January 2018 through December 2018 period.

The actual end-of-period over-recovery for the period January 2016 through December 2016 of $17,226,490 shown on line 1 less the actual/estimated end-of-period over-recovery for the same period of $9,639,909 shown on line 2 that was approved by the Commission in Order No. PSC-16-0547-FOF-EI, results in the net true-up over-recovery for the period January 2016 through December 2016 of $7,586,581 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 2016 through December 2016 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 2016?

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 2016 through December 2016. Actual jurisdictional capacity charges were $6.4 million lower than projected and actual revenues were $1.2 million higher than expected, resulting in the net over-recovery of $7.6 million.

Q. Please describe the major components of the variance in net capacity charges.

A. Appendix II, page 3, line 17 provides the variance in jurisdictional capacity charges, which is a decrease of $6,374,208. This $6.4 million decrease was primarily due to a $6.6 million decrease in Incremental Plant Security Costs - O&M, and a $1.7 million increase in Transmission Revenues from Capacity Sales.

These decreases were partially offset by a $0.8 million increase in Payments to

Non-cogenerators and a $0.8 million increase in Incremental NRC Compliance Costs (Fukushima) - O&M.

<u>Incremental Plant Security Costs - O&M - $6.6 million decrease (Appendix II, page 3, line 7)</u>

The variance for Incremental Plant Security O&M costs is primarily attributable to the implementation of cost savings initiatives at St. Lucie and Turkey Point. Additionally, costs associated with Cyber Security Common Controls were deferred to 2017 due to prioritization of cyber security required modifications over program procedure development in 2016. The FPL NERC CIP Low Impact assessment work was also deferred to 2017 due to delays in the contractor bidding process. Finally, the Threat Vulnerability Assessment project was postponed.

<u>Transmission Revenues from Capacity Sales - $1.7 million increase (Appendix II, page 3, line 12)</u>

The variance for Transmission Revenues from Capacity Sales is attributable to higher than projected economy sales. FPL sold 390,965 MWh more of economy power during the period than projected, resulting in higher transmission revenues.

<u>Payments to Non-Cogenerators - $0.8 million increase (Appendix II, page 3, line 1)</u>

The variance for Payments to Non-Cogenerators (SJRPP, SWA and UPS) is attributable to higher than projected costs associated with the SJRPP agreement. An increase in costs of approximately $0.9 million for Cumulative Capital

Recovery Amount payments and approximately $0.4 million for O&M and Inventory costs was partially offset by slightly lower than projected costs for Debt Service of $0.03 million and Property Taxes of $0.3 million.

<u>Incremental Nuclear NRC Compliance Costs (Fukushima) – O&M - $0.8 million increase (Appendix II, page 3, line 9)</u>

The variance for Incremental NRC Compliance O&M costs is primarily attributable NRC Flooding protection requirements at Turkey Point being booked as O&M rather than capital as originally projected.

Q. Please describe the variance in CCR revenues.

A. As shown on page 3, line 18, actual Capacity Cost Recovery Revenues (Net of Revenue Taxes), were $1,200,918 higher than the actual/estimated projection. This was primarily due to higher than projected jurisdictional sales, which were 1,045,622 MWh, higher than the actual/estimated projection.

Q. Have you provided a schedule 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 2016 through December 2016. Page 5 provides the Short Term Capacity Payments for the period January 2016 through December 2016.

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 2016 through December 2016 are included on pages 12 and 13 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 RENAE B. DEATON

DOCKET NO. 20170001-EI

JULY 27, 2017

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. 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 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 2017 through December 2017.

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

A. Yes, various schedules are included in Exhibit RBD-3 and Exhibit RBD-4. Exhibit RBD-3 contains the FCR related schedules and Exhibit RBD-4 contains the CCR related schedules.

The FCR schedules contained in Exhibit RBD-3 include Schedules E3 through E9 that provide actual data for the period January 2017 through June 2017 and revised estimates for the period July 2017 through December 2017. The actual data was derived from the FCR A-Schedules A1 through A9 that are filed monthly with the Commission and served on all parties, which are incorporated herein by reference. The FCR schedules contained in Exhibit RBD-3 also provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2017 through December 2017.

The CCR schedules contained in Exhibit RBD-4 provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2017 through December 2017.

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

A. Unless otherwise indicated, the actual 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-up amounts presented in your testimony.

A. The FCR and CCR true-up calculations compare actual/estimated data consisting of actuals for January 2017 through June 2017 and revised estimates for July 2017 through December 2017 to the data reflected in FPL's original projections for the period January 2017 through December 2017 filed on September 2, 2016.

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

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 for the twelve month period by 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 on the Federal Reserve website on the first business day of the current month and the subsequent month divided by two. The average interest rate for the projected months is the actual rate published on the first business day in July 2017, which reflects the interest rate from the last business day in June 2017.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2017 actual/estimated true-up by month?

A. Yes. Exhibit RBD-3, page 1 shows the calculation of the FCR actual/estimated true-up by month for the period January 2017 through December 2017.

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. Exhibit RBD-3, page 1 shows the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts. The 2017 end-of-period net true-up amount to be carried forward to the 2018 FCR factors is an over-recovery of $16,792,378 (page 1, line 50, column 15). This $16,792,378 over-recovery includes the 2016 final true-up under-recovery of $28,780,519 (Exhibit RBD-3, page 1, line 47, column 15), filed with the Commission on March 1, 2017, and the actual/estimated true-up over-recovery, including interest, of $45,572,897 (Exhibit RBD-3, page 1, lines 43 plus 44, column 15) for the period January 2017 through December 2017.

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

A. Yes.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and the projections for 2017?

A. Yes. Exhibit RBD-3, page 2 provides a variance calculation that compares the 2017 actual/estimated period data by component to the same components from the 2017 original projection filing.

Q. Please summarize the variance schedule on page 2 of Exhibit RBD-3.

A. FPL originally projected jurisdictional total fuel costs and net power transactions to be $2.966 billion for 2017 (Exhibit RBD-3, page 2, line 42, column 4). The actual/estimated jurisdictional total fuel costs and net power transactions are now projected to be $2.939 billion for that period (Exhibit RBD-3, page 2, line 42, column 3). Jurisdictional total fuel costs and net power transactions are projected to be $27.2 million, or 0.9% lower than the original projection (Exhibit RBD-3, page 2, line 42, column 5) and jurisdictional fuel revenues, net of revenue taxes for 2017 are projected to be $18.5 million, or 0.6% higher than the original projection (Exhibit RBD-3, page 2, line 33, column 5).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $27.2 million variance.

<u>Energy Payments to Qualifying Facilities: $39.5 million decrease (Exhibit RBD-3, page 2, line 9, column 5)</u>

Consistent with Commission Order No. PSC-2016-0506-FOF-EI, issued in Docket No. 20160154-EI on November 2, 2016, energy costs associated with the Indiantown Cogeneration L.P. ("ICL") facility ("Indiantown") purchased power agreement ("PPA") are no longer being recovered through the FCR Clause. The removal of the energy payments associated with Indiantown resulted in a decrease of $37.5 million. In addition, FPL now projects lower than originally projected costs related to as-available energy purchases and higher than projected as-available energy purchases, resulting in a net decrease for as-available purchases of $1.8 million. The remainder of the variance, a $0.2 million decrease, is related to higher than projected firm co-generation purchases offset by lower than originally projected energy costs.

<u>Fuel Cost of Stratified Sales: $21.0 million increase (Exhibit RBD-3, page 2, line 7, column 5)</u>

A credit of $21.0 million related to the fuel cost of stratified sales is included in the 2017 actual/estimated true-up. FPL has two stratified contracts in effect in 2017: (1) a Seminole 200 MW intermediate contract, and (2) a New Smyrna Beach 20 MW peaking contract. The fuel costs charged to Seminole and New Smyrna Beach are calculated based on a guaranteed heat rate and a fuel price index. 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 cost of the stratified 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. This adjustment was performed in the same manner that off-system sales are removed from the calculation, consistent with Order No. PSC-1997-0262-FOF-EI.

<u>Fuel Cost of Purchased Power: $13.6 million decrease (Exhibit RBD-3, page 2, line 8, column 5)</u>

The variance for the fuel cost of purchased power is primarily attributable to lower than projected SJRPP purchases and lower than projected SWA purchases and costs. FPL now projects to purchase 1,513,995 MWh, or 344,792 MWh less than originally projected from SJRPP, resulting in a total decrease for SJRPP of $9.3 million. In addition, FPL now projects to purchase 875,371 MWh, or 35,669 MWh less from SWA at an average unit cost that is $3.96/MWh lower than originally projected, resulting in a total decrease for SWA of $4.7 million. The total decrease of $14.0 million for SJRPP and SWA is partially offset by an increase of $0.4 million that is primarily attributable to higher than projected purchases under the St. Lucie Reliability Exchange. FPL now projects to purchase 534,838 MWh, or 66,503 more than originally projected under the St. Lucie Reliability Exchange.

<u>Gains from Off-System Sales: $2.0 million increase (Exhibit RBD-3, page 2, line 6, column 5)</u>

The variance for gains from off-system sales is attributable to higher than projected margins on economy sales coupled with lower than projected economy sales. FPL now projects an average economy sales margin of $7.50/MWh, or $1.56/MWh higher than originally projected on sales of 1,923,330 MWh, resulting in an increased gain of $3.0 million. This variance is partially offset by a $1.0 million decrease due to lower than projected economy sales.

<u>Variable Power Plant O&M Costs Attributable to Off-System Sales: $0.1 million decrease (Exhibit RBD-3, page 2, line 15, column 5)</u>

The variance for variable power plant O&M attributable to off-system sales is due to lower than originally projected economy sales.

<u>Fuel Cost of Power Sold: $7.4 million decrease (Exhibit RBD-3, page 2, line 5, column 5)</u>

The variance for the fuel cost of power sold is primarily attributable to lower than projected economy sales and fuel costs related to economy sales. FPL now projects to sell 1,923,330 MWh of economy power, or 172,370 MWh less than projected, at an average associated fuel cost that is $1.54/MWh less than the original projections. The combination of lower economy sales and lower fuel costs associated with economy sales results in a total decrease for economy sales of $7.5 million. The remaining decrease of $0.1 million is primarily attributable to higher than projected St. Lucie Plant Reliability Exchange sales. FPL now projects to sell 626,787 MWh, or 12,183 MWh more than originally projected under the St. Lucie Reliability Exchange.

<u>Energy Cost of Economy Purchases: $4.5 million increase (Exhibit RBD-3, page 2, line 10, column 5)</u>

The variance for the energy cost of economy purchases is attributable to higher than projected costs for economy power and lower than originally projected economy purchases. FPL now projects that the cost of economy power will be $5.17/MWh higher than originally projected, resulting in a variance of $6.5 million. This variance is partially offset by $2.0 million due to 73,841 MWh less than originally projected economy purchases. FPL now projects to purchase 1,258,259 MWh from economy purchases.

<u>Railcar Lease (Cedar Bay/Indiantown): $2.4 million increase (Exhibit RBD-3, page 2, line 4, column 5)</u>

The variance for the cost of the railcar leases (Cedar Bay/Indiantown) is primarily attributable to inclusion of the railcar lease associated with Indiantown, and 50% of 2017 estimated cost associated with the Cedar Bay railcar lease. In January 2017, FPL acquired Indiantown and assumed responsibility for the railcar lease associated with the transaction, which extends until January 2025. The cost of the Indiantown railcar lease, which is similar to that for Cedar Bay, could not have been included in the 2017 projections filing due to the timing of Commission approval and acquisition of Indiantown.

In accordance with the settlement agreement approved in Order No. PSC-2015-0401-AS-EI, FPL included in its 2017 original projections $720,000 for the Cedar Bay railcar lease, which was 50% of the expected lease charges. While the monthly lease charges are fixed and predictable, other cost elements associated with the railcar lease – such as management fees, storage/switching costs and railcar maintenance costs – are neither fixed nor predictable and therefore were not included in FPL's 2017 original projections.

<u>Incremental Personnel, Software, and Hardware Costs: $0.2 million increase (Exhibit RBD-3, page 2, line 14, column 5)</u>

The variance for incremental personnel, software, and hardware costs is primarily attributable to additional incremental O&M costs associated with a collaborative working engagement between FPL and Accenture LLP to review and validate FPL's current natural gas procurement and optimization processes and to determine the potential to derive additional value for FPL's customers from the daily execution of its natural gas procurement and optimization functions. This engagement took place over a 9-week period, during which time FPL's procurement and optimization processes related to forecasting, trading, scheduling, and deal capture were thoroughly reviewed and evaluated. Overall, the engagement proved beneficial in many different aspects, with the most important being confirmation that FPL's optimization program is effectively designed and is being implemented in a manner that maximizes customer benefits while continuing to deliver reliable fuel supply to its generating units. Additionally, the engagement allowed FPL to conceptually develop a framework for a software tool that could help consolidate critical trading, scheduling, and forecast data to improve the efficiency and decision-making process related to natural gas procurement and optimization. FPL is currently conducting a more detailed analysis to determine how best to proceed with the software concept.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2017 actual/estimated true-up by month?

A. Yes. Exhibit RBD-4, page 1 provides the calculation of the CCR actual/estimated true-up by month for the period January 2017 through December 2017.

Q. Please explain the calculation of the CCR 2017 end-of-period net true-up and actual/estimated true-up amounts you are requesting this Commission to approve.

A. As shown on Exhibit RBD-4, page 1, the 2017 end-of period net true up amount to be carried forward to the 2018 CCR factors is an over-recovery of $937,222 (line 29, column 15). This $937,222 net over-recovery is comprised of the 2016 final true-up over-recovery of $7,586,581 filed with the Commission on March 1, 2017 (line 26, column 15) and the actual/estimated true-up under-recovery of $6,710,872 for the period January 2017 through December 2017 (line 23, column 15) plus associated interest of $61,513 (line 24, column 15).

The CCR revenues (net of revenue taxes) are projected to be $3,790,784 (Exhibit RBD-4, page 2, line 19, column 5) lower than originally estimated. The $2,920,088 decrease in jurisdictional capacity costs (Exhibit RBD-4, page 2, line 18, column 5) less the $3,790,784 decrease in revenues results in the 2017 actual/estimated true-up under-recovery amount of $6,649,359, including interest (Exhibit RBD-4, page 2, lines 23 plus 24, column 5).

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

A. Yes.

Q. Have you provided a schedule showing the variances between the CCR actual/estimated and the original projections for 2017?

A. Yes. Exhibit RBD-4, page 2 shows the actual/estimated capacity costs and applicable revenues (January 2017 through June 2017 reflects actual data, while the data for July 2017 through December 2017 is based on updated estimates) compared to the original projections for the January 2017 through December 2017 period.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-4, page 2, line 18, column 5, the variance related to jurisdictional capacity costs is $2.9 million, a 0.9% increase from original projections. The primary reason for this variance is a $3.1 million or 0.9% increase in total system capacity costs (page 2, line 14, column 5).

Below are the primary reasons for the $3.1 million increase in total system capacity costs.

<u>Indiantown Transaction Regulatory Asset: $89.4 million increase (Exhibit RBD-4, page 2, line 5, column 5)</u>

The Indiantown transaction discussed previously resulted in a regulatory asset similar to that for Cedar Bay. The revenue requirements for the Indiantown transaction regulatory asset are estimated to be $89.4 million in 2017. As was the case for the Indiantown railcar lease expenses discussed previously, FPL was not able to include this estimate in the original projections filing due to the timing of the approval.

<u>Incremental NRC Compliance Capital Costs: $3.1 million increase (Exhibit RBD-4, page 2, line 11, column 5)</u>

As a result of the Stipulation and Settlement Agreement approved by the Commission in FPL's most recent base rate case (Order No. PSC-2016-0560-AS-EI, Docket No. 20160021-EI) ("2016 Base Rate Settlement Agreement"), FPL transferred the remaining portion of the incremental Nuclear Regulatory Commission

("NRC") compliance costs from base rates to the CCR Clause.

Payments to Non-Cogenerators: $2.7 million increase (Exhibit RBD-4, page 2, line 1, column 5)

The variance for payments to non-cogenerators (SJRPP & SWA) is attributable to higher than projected costs associated with the SJRPP agreement. An increase in costs of approximately $3.1 million resulted from higher than projected costs for cumulative capital recovery amount payments, partially offset by lower than projected costs for property taxes of $0.3 million, and O&M / inventory of $0.1 million.

Transmission of Electricity By Others: $0.9 million increase (Exhibit RBD-4, page 2, line 12, column 5)

The variance for transmission of electricity by others is due to a tariff rate true-up for transmission service purchased from Southern Company to support the UPS agreements. Approximately $0.9 million in additional transmission charges were billed by Southern Company for the period of January to May 2016 and paid in June 2017.

Payments to Co-Generators: $91.0 million decrease (Exhibit RBD-4, page 2, line 2, column 5)

The variance for payments to co-generators is primarily due to the approval of the Indiantown transaction.

<u>Transmission Revenues from Capacity Sales: $0.9 million decrease (Exhibit RBD-4, page 2, line 13, column 5)</u>

The variance for transmission revenues from capacity sales is attributable to slightly lower than projected economy sales. FPL now projects to sell 172,370 MWh less of economy power than originally projected, resulting in lower transmission revenues.

<u>Incremental Plant Security Capital Costs: $0.3 million decrease (Exhibit RBD-4, page 2, line 9, column 5)</u>

The variance for incremental plant security costs is primarily due to a delay in modifications to the Turkey Point Force-on-Force project because resources were dedicated to the Turkey Point refueling outage.

Indiantown Base Non-Fuel Revenue Requirements

Q. Has FPL included an adjustment to the 2017 CCR actual/estimated true-up revenues to account for the recovery of base non-fuel revenue requirements associated with Indiantown?

A. Yes. Recovery of the Indiantown base non-fuel revenue requirements through the capacity clause is provided in the order approving the Indiantown transaction. FPL has made the adjustment for the Indiantown base non-fuel revenue requirements consistent with the method previously used when the West County Energy Center Unit 3 ("WCEC3") non-fuel base revenue requirements were recovered through the capacity clause.

Q. Were the Indiantown base non-fuel revenue requirements included in FPL's 2017 CCR factors?

A. No. As discussed in the testimony of FPL witness Terry J. Keith filed in Docket No. 20160001-EI on September 2, 2016, which I adopted on October 3, 2016, FPL did not include the impact of the Indiantown transaction in the calculation of its 2017 CCR factors because the transaction had not yet been approved at the time of FPL's filing. In that testimony, FPL proposed to include an adjustment in the 2017 actual/estimated true-up to reflect the various impacts of the Indiantown transaction.

Q. What is the total jurisdictional amount associated with the Indiantown base non-fuel revenue requirements for the period January 2017 through December 2017?

A. The total jurisdictional non-fuel revenue requirement amount associated with the Indiantown transaction is $13,626,163. The calculation of this amount is shown in my Exhibit RBD-4, pages 12 and 13, and is based on the estimated O&M and actual plant values recorded on FPL's books and records on the date of the transaction, January 5, 2017.

Q. How was the adjustment to the 2017 CCR actual/estimated true-up revenues determined?

A. The adjustment was determined consistent with the method used for WCEC3. FPL used the Indiantown jurisdictional base non-fuel revenue requirements discussed above to calculate the Indiantown-related portion of the CCR factors by rate class shown on page 10 of RBD-4.

<u>2016 Base Rate Settlement Agreement Impact on the CCR Clause</u>

Q. Has FPL implemented any changes affecting the recovery of costs through the CCR Clause as a result of its most recent base rate case?

A. Yes. As a result of the 2016 Base Rate Settlement Agreement, FPL implemented two changes effective January 1, 2017, which affect the recovery of costs through the CCR Clause.

First, as discussed above, FPL has transferred the remaining portion of the incremental NRC compliance costs from base rates to the CCR Clause. FPL did not include this change in the calculation of its 2017 CCR factors. However, since the Commission approved the change in the 2016 Base Rate Settlement Agreement, it is appropriate to include it as part of the 2017 CCR true-up process. Second, FPL has moved the recovery of WCEC3 revenue requirements from the CCR Clause to base rates. This does not impact the 2017 actual/estimated true-up because FPL implemented the unadjusted CCR factors (excluding WCEC3) in January 2017.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20170001-EI

AUGUST 24, 2017

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. 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 this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- The FCR factors for the periods January 2018 through February 2018 and March 2018 through December 2018 that reflect the fuel savings associated with the two solar photovoltaic projects that are expected to enter commercial operation by January 1, 2018 and March 1, 2018 ("2017 Solar Project" and "2018 Solar Project," respectively);
- The 2018 FCR factors based on the traditional factor calculation method, which spreads the fuel savings associated with the 2017 and 2018 Solar Projects over the entire calendar year, for informational purposes;

- The calculation of the jurisdictional amount of FPL’s portion of the 2016 incentive mechanism gains for recovery through the 2018 FCR factors;
- The CCR factors for the period January 2018 through December 2018 and the CCR factors for the period January 2018 through December 2018 including an adjustment to recover the non-fuel revenue requirements associated with the Indiantown Cogeneration L.P. facility (“Indiantown”) for the period January 2018 through December 2018, as approved in Order No. PSC-16-0506-FOF-EI, issued in Docket No. 160154-EI on November 2, 2016;
- The non-fuel revenue requirement calculation for the Indiantown facility for the period January 2018 through December 2018; and
- FPL’s proposed cogeneration as-available energy (“COG-1”) tariff sheets, which reflect updated variable operation and maintenance expense and loss factors.

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:

Exhibit RBD-5 (Appendix II)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation, and E10 provide the calculation of FCR factors for January 2018 through February 2018, which include fuel savings for the 2017 Solar Project expected to be placed in service by January 1, 2018 and exclude fuel savings for the 2018 Solar Project expected to be placed in service by

March 1, 2018;

- Schedules E1-A, E1-C, E1-D, Calculation of Jurisdictional Incentive Mechanism Gains – FPL Portion, and H1, which pertain to the entire 2018 calendar year;
- Pages 9 through 12, which provide the 2018 Projected Energy Losses by Rate Class;
- Pages 90 and 91, which provide updated COG-1 tariff sheets;

Exhibit RBD-6 (Appendix III)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation, and E10 for the period March 2018 through December 2018, which include fuel savings for both the 2017 and 2018 Solar Projects;

Exhibit RBD-7 (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 2018 through December 2018 based on the traditional factor calculation methodology, which spreads fuel savings for the 2017 and 2018 Projects over the entire calendar year;

Exhibit RBD-8 (Appendix V)

- Pages 1 through 3 provide the calculation of the 2018 CCR factors excluding the Indiantown non-fuel revenue requirements for January 2018 through December 2018;
- Pages 4 through 11 provide the calculation of depreciation and return on incremental power plant security and incremental Nuclear

Regulatory Commission ("NRC") compliance capital investments;

- Page 12 provides the calculation of amortization and return on the regulatory asset related to the Cedar Bay Transaction;
- Page 13 provides the calculation of amortization and return on the regulatory liability related to the Cedar Bay Transaction;
- Page 14 provides the calculation of amortization and return on the regulatory asset related to Indiantown;
- Page 15 provides the capital structure components and cost rates relied upon to calculate the rate of return applied to capital investments and working capital amounts included for recovery through the CCR clause for the period January 2018 through December 2018;
- Pages 18 and 19 provide the calculation of the portion of the CCR factors that recovers the non-fuel revenue requirements associated with Indiantown for the period January 2018 through December 2018;
- Page 20 combines the results from pages 1 through 3 and pages 18 and 19 to provide the total 2018 CCR factors including the non-fuel revenue requirements associated with Indiantown for the period January 2018 through December 2018;
- Pages 21 and 22 provide the calculation of the Indiantown revenue requirements for January 2018 through December 2018;
- Pages 23 through 29 provide the calculations of stratified separation factors.

FUEL COST RECOVERY CLAUSE

Q. What adjustments are included in the calculation of the 2018 FCR factors shown on Schedules E1 included in Appendices II through IV?

A. The 2018 FCR factors include adjustments for the total net true-up, the Generating Performance Incentive Factor ("GPIF"), and the jurisdictional amount associated with FPL's share of the 2016 incentive mechanism gains. The total net true-up to be included in the 2018 FCR factors is an over-recovery of $16,792,378, as shown on line 29 of Schedule E1.

The GPIF testimony of witness Charles R. Rote, filed on March 15, 2017, proposes a reward of $9,656,036 for the period ending December 2016, as shown on line 33 of Schedule E1.

FPL is including $9,533,057 for the jurisdictional amount associated with its share of 2016 incentive mechanism gains in the calculation of its 2018 FCR factors, as shown on line 34 of Schedule E1.

As presented and explained in the direct testimony and exhibits of FPL witness Gerard J. Yupp filed on March 1, 2017 in this docket, FPL's activities under the incentive mechanism during 2016 delivered $62,835,808 in total gains. Of these total gains, FPL is allowed to retain $10,101,485 (system amount) per Order No. PSC-13-0023-S-EI dated January 14, 2013. FPL will reflect recovery of one-twelfth of the approved jurisdictional amount of $9,533,057, net of revenue taxes, in each month's Schedule A2 for the period January 2018 through December 2018 as a reduction to jurisdictional fuel revenues applicable to each period. The calculation of the jurisdictional amount of the 2016 incentive mechanism gains adjusted for revenue taxes is shown on page 4 of Appendix II.

Q. Please explain the adjustment reflected on line 3 of Schedule E1 related to the fuel cost of stratified sales.

A. FPL has included a credit of $31,564,646 associated with three stratified wholesale power sales contracts in effect in 2018: (1) a 200 MW intermediate contract with Seminole Electric Cooperative Inc., (2) a 20 MW peaking contract with the City of New Smyrna Beach, and (3) a combined intermediate / peaking contract with the Florida Public Utilities Company ("FPUC"). The fuel costs charged to Seminole, New Smyrna Beach and FPUC are calculated based on a guaranteed heat rate and a fuel price index. 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 cost of the stratified 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. This adjustment was performed in the same manner that off-system sales are removed from the calculation, consistent with Order No. PSC-97-0262-FOF-EI.

Calculation of 2018 FCR Factors

Q. Please explain how FPL has calculated its proposed FCR factors for the period January 2018 through December 2018 to reflect the impact of the fuel savings associated with the 2017 and 2018 Solar Projects.

A. Pursuant to the Stipulation and Settlement Agreement reached in FPL's most recent base rate case approved by the Commission in Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI ("2016 Base Rate Settlement Agreement"), FPL is authorized to recover through the Solar Base Rate Adjustment ("SoBRA") mechanism, the revenue requirements based on the first 12 months of operations of the 2017 and 2018 Solar Projects. The first SoBRA (associated with the 2017 Solar Project) is expected to be implemented on January 1, 2018 and the second SoBRA (associated with the 2018 Solar Project) is expected to be implemented on March 1, 2018. FPL proposes that the corresponding fuel savings associated with the 2017 and 2018 Solar Projects be reflected in the FCR factors concurrent with the SoBRA base rate increases in order to align costs with the fuel savings benefits. This treatment is consistent with past practice approved by the Commission.

Q. How would a delay in the commercial operation dates of the Solar Projects impact the FCR factors?

A. At this time, FPL does not anticipate a delay in the commercial operation dates of the 2017 or 2018 Solar Projects. Should FPL become aware of a delay, FPL will promptly provide notification to the Commission of such delay and provide updated in-service date(s). In order to limit changes to FCR factors, FPL intends to implement the proposed January 1, 2018 FCR factors including the 2017 Solar Project fuel savings on January 1, 2018 even if the 2017 Solar Project is delayed and base rates are not implemented until after January 1. For the 2018 Solar Project, FPL will implement FCR factors reflecting the 2018 Solar Project fuel savings concurrent with implementation of the SoBRA on or after the date of commercial operation.

Q. What are the projected fuel savings associated with the 2017 and 2018 Projects?

A. As explained in the testimony of FPL witness Yupp, the projected total fuel savings associated with the 2017 and 2018 Projects are $20,098,304 and $18,548,736, respectively.

Q. Please explain the calculation of 2018 FCR factors reflecting the fuel savings associated with the 2017 and 2018 Solar Projects.

A. FPL first calculates the FCR factors for the January 2018 through February 2018 period that include the fuel savings associated with the 2017 Solar Project that is scheduled to go in-service by January 1, 2018. These FCR factors assume the 2018 Solar Project is not yet operating and therefore exclude the associated fuel savings. This adjustment is shown on line 2 of Schedule E1 in Appendix II. This results in a levelized fuel factor of 2.650 cents per kWh for the period January 2018 through February 2018. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $23.17 during this period.

Next, FPL calculates FCR factors for the period March 2018 through December 2018 that include the fuel savings associated with the 2018 Solar Project during this period. This adjustment is shown on line 35 of Schedule E1 in Appendix III. Therefore, the FCR factors for the March 2018 through December 2018 period include the fuel savings associated with both 2017 and 2018 Solar Projects. This results in a levelized fuel factor of 2.630 cents per kWh for the period March 2018 through December 2018. For FPL's residential 1,000 kWh bill, this represents a fuel charge of $22.97 for during this 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 2018?

A. Yes. Although FPL requests approval of separate FCR factors for the January 2018 through February 2018 period and the March 2018 through December 2018 period that reflect the impact of the Solar Projects in those periods, FPL has also provided FCR 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 2.633¢ per kWh, based on the traditional methodology. This twelve-month levelized fuel factor spreads the fuel savings for the 2018 Solar Project throughout the twelve months of 2018.

CAPACITY COST RECOVERY CLAUSE

Q. Have you prepared a summary of the requested capacity costs for the projected period of January 2018 through December 2018?

A. Yes. Page 1 of Appendix V provides this summary. Total recoverable capacity costs for the period January 2018 through December 2018 are $275,974,426 (line 47). This includes $289,174,210 for the projected jurisdictional capacity costs, the net true-up over-recovery for 2016 and 2017 of $937,222 (line 41 plus line 42), the Port Everglades Energy Center ("PEEC") Generation Base Rate Adjustment ("GBRA") true-up refund amount of $5,155,918, the Nuclear Cost Recovery over-recovery of $7,305,202 and revenue taxes but excludes the 2018 Indiantown non-fuel revenue requirements.

Q. What are the projected Indiantown jurisdictional non-fuel revenue requirements for the January 2018 through December 2018 period?

A. The jurisdictional non-fuel revenue requirements for January 2018 through December 2018 are $4,022,504. The calculation of this amount is shown on Exhibit RBD-8, Appendix V. FPL has made an adjustment for the Indiantown non-fuel revenue requirements consistent with the method previously used when the West County Energy Center Unit 3 ("WCEC3") non-fuel revenue requirements were recovered through the capacity clause.

Q. Have you provided a calculation of 2018 CCR factors by rate class including an adjustment to recover the non-fuel revenue requirements associated with Indiantown for the period January 2018 through December 2018?

A. Yes. As approved in Order No. PSC-16-0506-FOF-EI, FPL has included on pages 21 and 22 of Exhibit RBD-8, Appendix V, the 2018 non-fuel revenue requirements associated with Indiantown of $4,022,504. Accordingly, page 20 of Exhibit RBD-8, Appendix V, shows the calculation of the 2018 CCR factors including the non-fuel revenue requirements associated with Indiantown for the period January 2018 through December 2018.

Q. Has FPL accounted for stratified wholesale power sales contracts in the jurisdictional separation of projected 2018 capacity costs?

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

As I explain earlier in my testimony, FPL has three stratified wholesale power sales contracts in effect in 2018 which are taking service under the intermediate and peaking strata. The separation factors for the intermediate and peaking strata were calculated in a manner consistent with the separation factors used for the non-nuclear contracts (expired) with the City of Key West ("CKW") in FPL's 2012 base rate case, Docket No. 120015-EI, and for both CKW and the Florida Keys Electric Cooperative in FPL's 2009 base rate case, Docket No. 080677-EI (the last FPL rate cases that were based on test years when those contracts were still in effect), and in prior base rate cases. The calculations of the stratified separation factors are provided in Appendix V, pages 23 - 29.

Q. When will the Commission approve FPL's Nuclear Cost Recovery amount to be included in the 2018 CCR factors?

A. The Commission is scheduled to approve the Nuclear Cost Recovery amount to be included in FPL's 2018 CCR factors at its October 17, 2017 Special Agenda Conference. If the Commission makes any changes to FPL's requested over-recovery amount of $7,305,202 on October 17, FPL will submit to the Commission, with copies to all parties, revised schedules showing the calculation of the 2018 CCR factors prior to the clause hearing scheduled to begin on October 25, 2017.

Q. Has FPL included an adjustment associated with its GBRA for PEEC?

A. Yes. Pursuant to Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013, a true-up of the PEEC GBRA is required if the actual costs are lower than projected. As such, FPL has included a credit of $5,155,918, including interest, (Appendix V, page 1, line 44) for the true-up of PEEC costs as a reduction in the calculation of its 2018 CCR factors. The calculation of this credit is discussed in the declaration and attachments of Tiffany C. Cohen.

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

A. Yes. Page 2 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 meter readings scheduled to be read on January 1, 2018 and that they remain effective 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 2018 Residential Bill</u>

Q. What is FPL's proposed preliminary residential 1,000 kWh bill for the period January 2018 through December 2018?

A. FPL's preliminary residential 1,000 kWh bill for January 2018 through February 2018 is $102.78. This preliminary bill includes a base rate charge of $66.49, which reflects the 2018 subsequent year rate increase and application of the SoBRA for the 2017 Solar Project, consistent with the 2016 Base Rate Settlement Agreement. Additionally, this preliminary bill includes an FCR charge of $23.17, which reflects fuel savings associated with the 2017 Solar Project, a CCR charge of $2.81, an environmental cost recovery charge of $1.59, a conservation cost recovery charge of $1.53, a storm charge of $1.26, an Interim Storm Restoration Surcharge of $3.36, and gross receipts tax of $2.57. Once the 2018 Solar Project is placed in-service, projected by March 1, 2018, FPL's base rate charge will increase to $67.10 to reflect the application of the SoBRA, the FCR charge will decrease to $22.97 to include the associated fuel savings, and the Interim

Restoration Surcharge will expire. FPL's preliminary residential 1,000 kWh bill for the period March 2018 through December 2018 is $99.75. FPL's proposed preliminary residential 1,000 kWh bills for 2018 are provided on Schedule E-10, which is page 7 of Appendix III.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 170001-EI

MARCH 1, 2017

Q. Please state your name and address.

A. My name is Gerard J. Yupp. 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 and Light Company (FPL) as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Please summarize your educational background and professional experience.

A. I graduated from Drexel University with a Bachelor of Science Degree in Electrical Engineering in 1989. I joined the Protection and Control Department of FPL in 1989 as a Field Engineer where I was responsible for the installation, maintenance, and troubleshooting of protective relay equipment for generation, transmission and distribution facilities. While employed by FPL, I earned a Masters of Business Administration degree from Florida Atlantic University in 1994. In 1996, I joined the Energy Marketing and Trading Division

("EMT") of FPL as a real-time power trader. I progressed through several power trading positions and assumed the lead role for power trading in 2002. In 2004, I became the Director of Wholesale Operations and natural gas and fuel oil procurement and operations were added to my responsibilities. I have been in my current role since 2008. On the operations side, I am responsible for the procurement and management of all natural gas and fuel oil for FPL, as well as all short-term power trading activity. My regulatory responsibilities include the preparation of testimony for all fossil fuel, interchange, and hedging-related areas for the Fuel and Capacity Cost Recovery Clauses, including the preparation of Discovery and audit responses. Finally, I am responsible for the oversight of FPL's optimization activities associated with the Incentive Mechanism.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (1) present the final true-up amounts for the July through December 2016 period related to the removal of the Woodford Gas Reserves Project ("Woodford") expenses from the Fuel Clause and (2) present the 2016 results of FPL's activities under the Incentive Mechanism that was approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI.

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

A. Yes, I am sponsoring the following exhibits:

- GJY-1, consisting of 3 pages:
  - Page 1 – Original Woodford Refund Calculation
  - Page 2 – Updated Woodford Refund Calculation
  - Page 3 – Woodford Final True-Up Summary
- GJY-2, consisting of 4 pages:
  - Page 1 – Total Gains Schedule
  - Page 2 – Wholesale Power Detail
  - Page 3 – Asset Optimization Detail (Confidential)
  - Page 4 – Incremental Optimization Costs

WOODFORD FINAL TRUE-UP

Q. Have you previously filed testimony related to FPL's removal of all Woodford expenses from the Fuel Clause?

A. Yes. As part of FPL's August 4, 2016 Actual/Estimated True-Up filing in Docket No. 160001-EI, I provided detailed testimony describing the calculations FPL utilized to remove all costs related to Woodford from the Fuel Clause, based on actual data through June 2016 and projections for the remainder of the year.

Q. Please summarize the approach that FPL utilized to "unwind" all of the Woodford expenses from the Fuel Clause.

A. As described in my previous testimony, the "unwinding" of the Woodford expenses from the Fuel Clause occurred in two distinct parts. First, FPL calculated a refund that customers would receive for the difference between the actual Woodford expenses from March 2015 through June 2016 and the amount that the volume of natural gas that FPL received from Woodford would have cost customers if FPL had procured that volume in the market. FPL used the Columbia Gulf Mainline Index to determine the market price of natural gas. This index represented the price FPL would have paid for natural gas delivered into the Southeast Supply Header ("SESH") pipeline, which is the location at which FPL delivered the Woodford production volume. On a delivered basis to FPL's system, Columbia Gulf Mainline Index prices were the lowest of the indices for the various locations at which FPL purchases natural gas. The balance of "unwinding" the Woodford expenses would occur through the normal true-up process in the Fuel Clause. For reference, the calculations that were utilized for each part described above and that were provided with my previous testimony are included with this testimony on Page 1 of Exhibit GJY-1.

Q. Do FPL's final true-up calculations for 2016 include any updates to the removal of the Woodford expenses from the Fuel Clause?

A. Yes. As I described in my previous testimony (Page 6, Line 14 through Page 7, Line 6), the true-up portion for the July 2016 through December 2016 period was an estimate at the time of FPL's Actual/Estimated True-Up filing, as actual market prices were not yet known. At that time, based on the July 5, 2016 forecast for Columbia Gulf Mainline natural gas prices, FPL estimated that the difference between the projected Woodford expenses that were included in FPL's 2016 FCR factors and the market price of natural gas would result in a true-up for the July 2016 through December 2016 period of $1,224,061. This calculation is shown on Page 1 of Exhibit GJY-1 (Table 2, Column J, Rows 7 through 13). FPL now has actual market prices for the Columbia Gulf Mainline index over the July 2016 through December 2016 period. As shown on Page 2 of Exhibit GJY-1 (Table 2, Column J, Rows 7 through 13), the total true-up over that time period, based on actual market prices, was $1,631,772.

Q. Did FPL include the estimated true-up amount of $1,224,061 for the July 2016 through December 2016 in its 2017 FCR factors?

A. Yes, with one modification. At the time of its 2017 FCR Projection Filing (September 6, 2016), FPL incorporated July "actuals" into its

2016 estimated year-end true-up balance. Therefore, the actual true-up amount of $389,657 related to Woodford for July 2016 (Page 2 of Exhibit GJY-1, Table 2, Column J, Row 7) was substituted for the estimated July 2016 true-up of $108,466 (Page 1 of Exhibit GJY-1, Table 2, Column J, Row 7) and the original estimated true-up amounts for the August 2016 through December 2016 were incorporated into FPL's 2017 FCR factors. This total of $1,505,252 is shown on Page 3 of Exhibit GJY-1 (Table 1, Column J, Rows 1 through 7).

Q. Is there a portion of the total true-up related to Woodford that will be carried into FPL's 2018 FCR factors?

A. Yes. The final true-up of $126,520 related to Woodford will be carried forward and included in FPL's 2018 FCR factors. This amount represents the difference between the actual true-up amount of $1,631,772 related to Woodford for July 2016 through December 2016 and the amount of $1,505,252 for the same time period that was included in FPL's 2017 FCR factors. The calculation of this final true-up amount is shown on Page 3 of Exhibit GJY-1 (Table 1, Column K, Rows 1 through 7).

Q. Will incorporation of the final true-up amount of $126,520 into FPL's 2018 FCR factors complete the removal of all Woodford expenses from the Fuel Clause?

A. Yes. FPL's calculated refunds reflect actual data for all of 2015 and

2016, the two years that were impacted by the Woodford project.

2016 INCENTIVE MECHANISM RESULTS

Q. Please provide an overview of the Incentive Mechanism under which FPL has operated for the period 2013 through 2016.

A. The Incentive Mechanism is an expanded optimization program that is designed to create additional value for FPL's customers while also providing an incentive to FPL if certain customer-value thresholds are achieved. It was created by the Stipulation and Settlement that was approved in FPL's 2012 rate case by Order No. PSC-13-0023-S-EI. The Incentive Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization. These other forms of asset optimization include, but are not limited to, natural gas storage optimization, natural gas sales, capacity releases of natural gas transportation, capacity releases of electric transmission and potentially capturing additional value from a third party in the form of an Asset Management Agreement ("AMA"). Under the Incentive Mechanism, customers receive 100% of the gains up to $46 million. Incremental gains above $46 million are to be shared between FPL and customers as follows: customers receive 40% and FPL receives 60% of the incremental gains between $46 million and

$100 million; and customers receive 50% and FPL receives 50% of all incremental gains above $100 million. FPL is allowed to recover reasonable and prudent incremental O&M costs incurred in implementing the expanded optimization program under the Incentive Mechanism, including incremental personnel, software and associated hardware costs, as well as variable power plant O&M costs incurred to make wholesale sales above 514,000 MWh (the level of wholesale sales that were assumed in forecasting FPL's 2013 test year power plant O&M costs in the MFRs filed in FPL's 2012 rate case).

Q. Please summarize the activities and results of the Incentive Mechanism for 2016.

A. FPL's activities under the Incentive Mechanism in 2016 delivered $62,835,808 in total gains. During 2016, FPL's activities under the Incentive Mechanism included wholesale power purchases and sales, natural gas sales in the market and production areas, gas storage utilization, and the capacity release of firm natural gas transportation and firm electric transmission. Additionally, FPL entered into an Asset Management Agreement related to a small portion of upstream gas transportation during 2016. The total gains of $62,835,808 exceeded the sharing threshold of $46 million. Therefore, the incremental gains above $46 million will be shared between customers and FPL, 40% and 60%, respectively. Exhibit

GJY-2, Page 1, shows monthly gain totals, threshold levels and the final gains allocation for 2016.

Q. Please provide the details of FPL's wholesale power activities under the Incentive Mechanism for 2016.

A. The details of FPL's 2016 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-2. FPL had gains of $18,695,359 on wholesale sales and savings of $25,493,744 on wholesale purchases for the year.

Q. Please provide the details of FPL's asset optimization activities under the Incentive Mechanism for 2016.

A. The details of FPL's 2016 asset optimization activities are shown on Page 3 of Exhibit GJY-2. FPL had a total of $18,646,705 of gains that were the result of nine different forms of asset optimization.

Q. Did FPL engage in any new forms of asset optimization during 2016?

A. Yes. FPL engaged in two new forms of asset optimization during 2016. First, FPL was able to deliver almost $657,000 in additional customer value by moving quickly to sell its banked 2015 Ozone Season NOx Allowances. In September 2016, the Environmental Protection Agency ("EPA") published its final Cross-State Air Pollution Rule ("CSAPR") which removed Florida from the program beginning in January 2017. This change in the final rule provided FPL with a limited window of opportunity to sell its banked allowances and deliver incremental value to customers. Second, FPL was able to reduce the consumption of higher cost fuels across several peak demand months through the advanced purchase of delivered natural gas in the Market Area. These delivered natural gas purchases resulted in customer savings of nearly $1.98 million.

Q. Did FPL incur incremental O&M expenses related to the operation of the Incentive Mechanism in 2016?

A. Yes. FPL incurred personnel expenses of $428,815 related to the costs associated with an additional two and one-half personnel required to support FPL's expanded activities under the Incentive Mechanism. FPL also incurred $55,490 in expenses related to licensing fees of OATI WebTrader software. In total, FPL incurred incremental O&M expenses related to the operation of the Incentive Mechanism of $484,305 in 2016. Additionally, FPL's actual wholesale power sales from its own generation resources in 2016 totaled 2,478,700 MWh, or 1,964,700 MWh above the 514,000 MWh threshold, resulting in variable power plant O&M expenses of $2,671,992 (reflects the volume above the threshold multiplied by $1.36/MWh; the average variable power plant O&M cost per MWh reflected in the 2013 test year MFRs). Page 4 of Exhibit GJY-2 provides the details of FPL's Incremental Optimization Costs for 2016.

Q. **Overall, were FPL's activities under the Incentive Mechanism successful in 2016?**

A. Yes. FPL's activities under the Incentive Mechanism were highly successful in 2016. On the wholesale power side, similar to 2015, suitable market conditions in the first quarter helped drive strong wholesale power sales and high demand during the summer peak period provided the opportunity to purchase power from the market to avoid running more expensive generation. Overall, FPL was able to consistently take advantage of power market opportunities throughout the year to deliver slightly more than $44 million in customer benefits. Asset optimization activities related to natural gas that had not taken place prior to the inception of the Incentive Mechanism generated nearly $13.9 million in gains, and optimization of FPL's firm transmission service on the Southern Company system added another $4.1 million in gains. In total, these activities delivered $62,835,808 of gains, which contrast very favorably to the total optimization expenses (personnel and variable power plant O&M) of $3,156,297.

Q. **Does this conclude your testimony?**

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 170001-EI

APRIL 3, 2017

Q. Please state your name and address.

A. My name is Gerard J. Yupp. 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 Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present data on FPL's hedging activities, by month, for calendar year 2016. This data is required per Item 5 of the Resolution of Issues that was approved by the Commission in Order No. PSC-02-1484-FOF-EI, issued on October 30, 2002, which states:

> 5. Each investor-owned utility shall provide, as part of its final true-up filing in the fuel and purchased power cost recovery

> docket, the following information: (1) the volumes of each fuel the utility actually hedged using a fixed price contract or instrument; (2) the types of hedging instruments the utility used, and the volume and type of fuel associated with each type of instrument; (3) the average period of each hedge; and (4) the actual total cost (e.g., fees, commissions, options premiums, futures gains and losses, swaps settlements) associated with using each type of hedging instrument.

The requirement for this data was further clarified in Section III of the Hedging Order Clarification Guidelines that were approved by the Commission in Order No. PSC-08-0667-PAA-EI, issued on October 8, 2008.

Q. Are you sponsoring an exhibit for this proceeding?

A. Yes. I am sponsoring Exhibit GJY-3 –2016 Hedging Activity True-Up (Pages 1 through 13).

Q. Does your Exhibit GJY-3 provide the detail on FPL's 2016 hedging activities required by Item 5 of the Resolution of Issues?

A. Yes. All hedging activity details required by Item 5 of the Resolution of Issues are included on pages 1 through 13 of Exhibit GJY-3.

Q. Please describe FPL's hedging objectives.

A. Consistent with the guiding principles described in Section IV of the Hedging Order Clarification Guidelines, the primary objective of

FPL's hedging program is to reduce the impact of fuel price volatility in the fuel adjustment charges paid by FPL's customers. FPL does not execute speculative hedging strategies aimed at "out guessing" the market. For natural gas purchases in 2016, FPL implemented a well-disciplined, well-defined and well-controlled hedging program in compliance with FPL's 2015 Risk Management Plan that was approved by the Commission in Order No. PSC-14-0701-FOF-EI issued on December 19, 2014.

Q. Please summarize FPL's 2016 hedging activities.

A. Consistent with its approved 2015 Risk Management Plan, FPL hedged a portion of its natural gas fuel portfolio for 2016 utilizing financial swaps.

Overall, actual 2016 natural gas prices settled, on average, approximately $0.62 per MMBtu lower than the forward prices that were in effect when FPL was executing its financial swaps for 2016. As would be expected under the approved hedging approach, this decrease in natural gas prices resulted in reported natural gas hedging costs for the year of $223,649,160, as shown on Exhibit GJY-3.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20170001-EI

AUGUST 24, 2017

Q. Please state your name and address.

A. My name is Gerard J. Yupp. 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 and Light Company ("FPL") as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) the dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas; (2) the availability of natural gas to FPL; (3) generating unit heat rates and availabilities; and (4) the quantities and costs of wholesale (off-system) power sales and purchased power transactions. I also review the interim results of FPL's 2017 hedging program. Additionally, my testimony addresses the Incremental Optimization Costs included in FPL's 2018 Projection Filing pursuant to the Incentive Mechanism approved in Order No. PSC-16-0560-AS-EI dated December 15, 2016 ("2016 Base Rate Settlement Agreement") and the 2016 results of the Incentive Mechanism that was approved in Order No. PSC-13-0023-S-EI dated January 14, 2013. Lastly, I present the projected fuel savings resulting from the commercial operation of four new solar energy centers estimated to be placed into service on January 1, 2018 and four new solar energy centers estimated to be placed into service on March 1, 2018.

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

A. Yes, I am sponsoring the following exhibits:

- GJY-4: 2017 Hedging Activity Supplemental Report (January through July)
- GJY-5: Appendix I
- Schedules E2 through E9 of Appendix II

<u>FUEL PRICE FORECAST</u>

Q. What forecast methodologies has FPL used for the 2018 recovery period?

A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve). For light and heavy fuel oil prices, FPL utilizes Over-The-Counter ("OTC") forward market prices. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. The forward curves for both natural gas and fuel oil represent expected future prices at a given point in time. The basic assumption made with respect to using the forward curves is that all available data that could impact the price of natural gas and fuel oil in the short-term is incorporated into the curves at all times. FPL utilized forward curve prices from the close of business on July 28, 2017 for its 2018 projection filing, which is the most current information that could be incorporated into FPL's schedule for calculating the 2018 FCR Clause factors.

Q. Has FPL used these same forecasting methodologies previously?

A. Yes. FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices in 2004 for its 2005 projections and has used this methodology consistently since that time.

Q. What are the factors that can affect FPL's natural gas prices during the January through December 2018 period?

A. In general, the key physical factors are (1) North American natural gas demand and domestic production; (2) the level of working gas in underground storage throughout the period; (3) weather (particularly in the winter period); (4) the potential for imports and/or exports of natural gas; and (5) the terms of FPL's natural gas supply and transportation contracts.

In its July 2017 Short-Term Energy Outlook, the Energy Information Administration ("EIA") forecasts natural gas prices to average approximately $3.10 per MMBtu in 2017 and $3.40 per MMBtu in 2018. The EIA expects production to increase through 2018 in response to forecast price increases and to support continuing growth in exports to Mexico and large increases in liquefied natural gas ("LNG") exports. Working natural gas rigs are up approximately 133% since the low mark in August 2016. Natural gas production is expected to grow by an average rate of 1.4% in 2017 and 4.3% in 2018.

Total natural gas consumption in 2017 is forecasted to decrease by 2.3 billion cubic feet ("BCF") per day from average 2016 consumption levels and then increase by 2.7 BCF per day in 2018. For 2017, decreases in natural gas consumption are mainly due to lower use in the electric power sector. Natural gas consumption in the power sector is projected to decrease by 9.4% in 2017 and then increase slightly (2.4%) in 2018. The EIA expects residential and commercial gas consumption to remain essentially unchanged in 2017 when compared to 2016, but increase in 2018 largely due to a forecasted return to normal temperatures in the first quarter of the year. Industrial sector consumption is expected to increase by 1.4% in 2017 and by 2.6% in 2018 as new fertilizer and chemical projects come online. Natural gas storage levels, a key benchmark for the supply/demand balance, are currently projected to reach approximately 3.94 trillion cubic feet at the end of October 2017, which would be 2% higher than the five-year average level for the end of October, but 2% lower than the level at the end of October 2016.

Q. Please describe FPL's natural gas transportation portfolio for the January through December 2018 period.

A. FPL utilizes the Florida Gas Transmission Company, LLC ("FGT"), Gulfstream Natural Gas System, LLC ("Gulfstream"), Sabal Trail Transmission, LLC ("Sabal Trail"), and Florida Southeast Connection, LLC ("FSC") pipelines to deliver natural gas to its generation facilities. FPL's total firm transportation capacity ranges from 1,150,000 to 1,274,000 MMBtu/day on FGT, 695,000 MMBtu/day on Gulfstream and 400,000 MMBtu/day on Sabal Trail/FSC. Additionally, FPL projects that during the January through December 2018 period, varying levels of non-firm natural gas transportation capacity will be available, depending on the month.

FPL also has firm transportation capacity on several upstream pipelines that provide FPL access to on-shore gas supply. FPL has 580,000 MMBtu/day of firm transport on the Southeast Supply Header ("SESH") pipeline, 121,500 MMBtu/day of firm transport on the Transcontinental Gas Pipe Line Company, LLC ("Transco") Zone 4A lateral, and 200,000 MMBtu/day (January through March and November through December) to 345,000 MMBtu/day (April through October) of firm transport on the Gulf South Pipeline Company, LP ("Gulf South") pipeline. The firm transportation on the SESH, Transco, and Gulf South pipelines does not increase transportation capacity into the state; however, FPL's firm transportation rights on these pipelines provide access for up to 1,046,500 MMBtu/day during the summer season of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply.

Q. Please describe FPL's natural gas storage position.

A. FPL currently holds 4.0 BCF of firm natural gas storage capacity in Bay Gas Storage, located in southwest Alabama. While the acquisition of upstream transportation capacity (i.e., SESH) has helped mitigate a large portion of risk associated with off-shore natural gas supply, natural gas storage capacity remains an important part of FPL's gas portfolio. Approximately 12% of FPL's supply continues to be sourced from off-shore sources. Additionally, as FPL's reliance on natural gas has increased, the importance of natural gas storage in helping balance consumption "swings" due to weather and unit availability has also increased. Storage capacity improves reliability by providing a relatively inexpensive insurance policy against supply and infrastructure problems while also increasing FPL's ability to manage supply and demand on a daily basis.

Q. What are FPL's projections for the dispatch cost and availability of natural gas for the January through December 2018 period?

A. FPL's projections of the system average dispatch cost and availability of natural gas, by transport type, by pipeline and by month, are provided on page 3 of Appendix I.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2018 period?

A. The key factors that could affect FPL's price for heavy oil are (1) worldwide demand for crude oil and petroleum products (including domestic heavy fuel oil); (2) non-OPEC crude oil supply; (3) the extent to which OPEC adheres to its quotas and reacts to fluctuating demand for OPEC crude oil; (4) the political and civil tensions in the major producing areas of the world like the Middle East and West Africa; (5) the availability of refining capacity; (6) the price relationship between heavy fuel oil and crude oil; (7) the supply and demand for heavy oil in the domestic market; (8) the terms of FPL's supply and fuel transportation contracts; and (9) domestic and global inventory.

Average heavy oil prices are forecasted to be slightly higher in 2018 compared with projected 2017 average levels primarily due to the assumed increase in the global crude oil price. The recent global crude oil price increases reflect more balanced market demand/supply fundamentals. In its July 2017 Short-Term Energy Outlook report, the EIA forecasts West Texas Intermediate crude oil prices will average approximately $49.01 per barrel in 2017 and $49.58 per barrel in 2018. The EIA anticipates global crude oil and other liquid fuels production to grow by 1.15 million barrels per day in 2017 and 1.87 million barrels per day in 2018, with consumption growing by approximately 1.54 million barrels per day in 2017 and 2018. U.S. crude oil and liquid fuels production is projected to increase by roughly 0.3 million barrels per day in 2017 and 0.36 million barrels per day in 2018. As always, an increase in geopolitical concerns could create upward pressure on oil prices.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2018 period.

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by month, is provided on page 3 of Appendix I.

Q. What are the key factors that could affect the price of light fuel oil?

A. The key factors are similar to those described for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2018 period.

A. FPL's projection for the system average dispatch cost of light oil, by month, is provided on page 3 of Appendix I.

Q. What is the basis for FPL's projections of the dispatch cost of coal for St. Johns' River Power Park ("SJRPP") and Plant Scherer?

A. FPL's projected dispatch costs for both plants are based on FPL's price projection for spot coal delivered to the plants.

Q. Please provide FPL's projection for the dispatch cost of coal at SJRPP and Plant Scherer for the January through December 2018 period.

A. FPL's projection for the system average dispatch cost of coal for this period, by plant and by month, is shown on page 3 of Appendix I.

Q. Do the fuel costs reflected on Schedule E3 for heavy oil, light oil and coal differ from the dispatch costs shown on page 3 of Appendix I?

A. Yes. FPL maintains inventories of those fuels and runs its plants out of that inventory. The dispatch costs reflect what FPL would pay to replace fuel that is removed from inventory to run the plants. On the other hand, the "charge out" costs for heavy oil, light oil and coal that are reflected on Schedule E3 are based on FPL's weighted average inventory cost, by month, for each fuel type.

<u>PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY</u>

Q. Please describe how FPL developed the projected Average Net Heat Rates shown on Schedule E4 of Appendix II.

A. The projected Average Net Heat Rates were calculated by the GenTrader model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to GenTrader for this calculation. The heat rate equations and efficiency factors are updated as appropriate based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, and/or from the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2018?

A. Yes. This data is shown on page 4 of Appendix I.

Q. How were the outage factors for this period developed?

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the period January through December 2018.

Q. Please describe the significant planned outages for the January through December 2018 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 1 is scheduled to be out of service from March 12, 2018 until April 11, 2018, or 30 days during the period. St. Lucie Unit 2 is scheduled to be out of service from August 27, 2018 until September 27, 2018, or 31 days during the period. Turkey Point Unit 3 is scheduled to be out of service from October 1, 2018 until November 12, 2018, or 42 days during the period.

Q. Please identify any changes to FPL's fossil generation capacity projected to take place during the January through December 2018 period.

A. As shown in FPL's 2017 Ten Year Power Plant Site Plan (Table ES-1, page 12), FPL projects a net increase in its 2018 summer firm capacity of 299 MW. The primary driver of this increase is related to the addition of 596 MW of solar generation. FPL assumes 54% of this generation to be firm capacity, resulting in a net increase of firm capacity for this solar generation of 322 MW.

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2018?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II of this filing.

Q. In what types of wholesale (off-system) power transactions does FPL engage?

A. FPL purchases power from the wholesale market when it can displace higher cost generation with lower cost power from the market. FPL will also sell excess power into the market when its cost of generation is lower than the market. FPL's customers benefit from both purchases and sales as savings on purchases and gains on sales are credited to customers through the Fuel Cost Recovery Clause. Power purchases and sales are executed under specific tariffs that allow FPL to transact with a given entity. Although FPL primarily transacts on a short-term basis (hourly and daily transactions), FPL continuously searches for all opportunities to lower fuel costs through purchasing and selling wholesale power, regardless of the duration of the transaction. Additionally, FPL is a member of the Florida Cost-Based Broker System ("FCBBS"). The FCBBS matches hourly cost-based bids and offers to maximize savings for all participants. Since its inception in 2010, membership in the FCBBS has dropped from 11 to 4 market participants. The steady decline in market participants and in the submission of hourly bids/offers has resulted in FCBBS annual costs exceeding overall annual savings on a state-wide basis. For these reasons, the FCBBS will be terminated effective January 1, 2018.

Q. Please describe the method used to forecast wholesale (off-system) power purchases and sales.

A. The quantity of wholesale (off-system) power purchases and sales are projected based upon estimated generation costs, generation availability, fuel availability, expected market conditions and historical data.

Q. What are the forecasted amounts and costs of wholesale (off-system) power sales?

A. FPL has projected 2,095,700 MWh of wholesale (off-system) power sales for the period of January through December 2018. The projected fuel cost related to these sales is $53,964,570. The projected transaction revenue from these sales is $73,340,370. After taking into account the transmission costs for those sales, the projected gain is $13,593,337.

Q. In what document are the fuel costs for wholesale (off-system) power sales transactions reported?

A. Schedule E6 of Appendix II provides the total MWh of energy, total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) power sales.

Q. What are the forecasted amounts and costs of wholesale (off-system) power purchases for the January to December 2018 period?

A. The costs of these economy purchases are shown on Schedule E9 of Appendix II. For the period, FPL projects it will purchase a total of 1,332,100 MWh at a cost of $42,485,160. If FPL generated this energy, FPL estimates that it would cost $49,989,060. Therefore, these purchases are projected to result in savings of $7,503,900.

Q. Does FPL have additional agreements for the purchase of electric power and energy that are included in your projections?

A. Yes. FPL purchases energy under two contracts with the Solid Waste Authority of Palm Beach County ("SWA"). In addition, FPL has entered into a firm capacity and energy agreement with Exelon Generation Company, LLC ("ExGen") for the May 1, 2018 through September 30, 2018 period. FPL also has contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission ("OUC") and Florida Municipal Power Agency ("FMPA"). Additionally, FPL purchases energy from JEA's portion of the SJRPP Units. Lastly, FPL purchases energy and capacity from Qualifying Facilities under existing tariffs and contracts.

Q. Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the January through December 2018 period.

A. Energy purchases under the SWA agreements are projected to be 911,040 MWh for the period at an energy cost of $27,846,781. Energy purchases from ExGen are projected to be 42,604 MWh for the period at an energy cost of $1,892,572. Energy purchases from the JEA-owned portion of SJRPP are projected to be 1,544,634 MWh for the period at an energy cost of $54,471,628. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, FPL projects purchases of 494,667 MWh at a cost of $3,516,934. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, FPL projects that purchases from Qualifying Facilities for the period will provide 593,515 MWh at a cost of $12,312,274.

Q. How does FPL develop the projected energy costs related to purchases from Qualifying Facilities?

A. For those contracts that entitle FPL to purchase "as-available" energy, FPL used its fuel price forecasts as inputs to the GenTrader model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanisms prescribed in the contracts are used to project monthly energy costs.

Q. What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

A. FPL projects to sell 574,035 MWh of energy at a cost of $3,739,447. These projections are shown on Schedule E6 of Appendix II.

HEDGING/ RISK MANAGEMENT PLAN

Q. Has FPL filed a comprehensive risk management plan for 2018, consistent with the Hedging Order Clarification Guidelines as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. No. Pursuant to Paragraph 16 of the 2016 Base Rate Settlement Agreement, FPL has terminated its fuel hedging program for the Minimum Term of the agreement.

Q. Has FPL filed a Hedging Activity Supplemental Report for 2017, consistent with the Hedging Order Clarification Guidelines, as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its Hedging Activity Supplemental Report for 2017 (January through July) on August 18, 2017. The Hedging Activity Supplemental Report is identified as Exhibit GJY-4.

Q. Have FPL's 2017 hedging strategies been successful in achieving FPL's hedging objectives?

A. Yes. FPL's hedging strategies have been successful in reducing fuel price volatility and delivering greater price certainty to its customers.

<u>THE INCENTIVE MECHANISM</u>

Q. What were the results of FPL's asset optimization activities under the Incentive Mechanism in 2016?

A. FPL's asset optimization activities in 2016 delivered total benefits of $62,835,808. The total gains exceeded the sharing threshold of $46 million and, therefore, the gains above $46 million will be shared between customers and FPL on a 40%/60% basis, respectively. In total, customers will receive $52,250,019 (net of FPL's share of the gain above the $46 million threshold, and after incremental personnel, software, and hardware expenses are removed), and FPL will receive $10,101,485. FPL's share of the gain is included for recovery in FPL's 2018 FCR Clause factors.

Q. Did the Incentive Mechanism allow FPL to deliver greater value to customers in 2016?

A. Yes. I have compared how customers would have fared under the prior wholesale-sales sharing mechanism with the results FPL has achieved under the Incentive Mechanism. For the purpose of this comparison, I have included the same savings of $51 million from optimization activities for power sales, power purchases and releases of electric transmission capacity under both mechanisms, as FPL was engaging in those activities prior to the Commission's approval of the Incentive Mechanism. For those savings, the previous sharing mechanism would have yielded net benefits to FPL's customers of $51 million, while FPL would not have shared in any benefits because the three-year rolling average threshold for wholesale sales would not have been exceeded.

In contrast, under the Incentive Mechanism, FPL also is incented to pursue beneficial natural gas transportation, storage and trading activities. These activities generated slightly more than $14.5 million of additional savings in 2016. When one takes into account these additional savings, less FPL's recovery of incremental optimization costs, the result is that FPL's customers received $52.3 million of savings under the Incentive Mechanism. This is $1.3 million more than customers would have received if the prior sharing mechanism were still in effect, clear proof that the Incentive Mechanism is working to deliver added value for customers as FPL and the Commission envisioned when it was approved.

Q. Has the Commission approved the continuation of the Incentive Mechanism beyond 2016?

A. Yes. Pursuant to Paragraph 15 of the 2016 Base Rate Settlement Agreement, FPL will continue its optimization activities under the Incentive Mechanism for the Minimum Term of the agreement.

Q. Did Paragraph 15 of the 2016 Base Rate Settlement Agreement include modifications to the Incentive Mechanism?

A. Yes. Two modifications to the Incentive Mechanism were approved. First, the sharing threshold was lowered from $46 million to $40 million. Second, FPL will now net economy sales and purchases to determine the impact of variable power plant O&M. For clarity, all other provisions of the Incentive Mechanism remain as described in Paragraph 12 of FPL's 2012 rate case settlement that was approved in Order No. PSC-13-0023-S-EI dated January 14, 2013.

Q. Has FPL included in its 2018 FCR factors, projections of the savings that it will achieve under the Incentive Mechanism?

A. Yes. FPL has included projections for savings on wholesale power purchases (Schedule E9), projections for gains on wholesale power sales (Schedule E6), and projections for other types of asset optimization measures (Schedule E3) for 2018.

Q. Has FPL included in its 2018 FCR factors, projections of the Incremental Optimization Costs that it will incur under the Incentive Mechanism?

A. Yes. FPL has included in its 2018 FCR factors, Incremental Optimization Costs from two categories: (i) incremental personnel, software and hardware costs associated with managing the various asset optimization activities, and (ii) variable power plant O&M ("VOM") costs associated with wholesale economy sales and purchases.

Q. Please describe the costs that are included in FPL's projections for incremental personnel, software and hardware expenses.

A. FPL projects to incur incremental expenses of $427,510 in 2018 for the salaries and expenses related to employees who were added in 2013 to support the Incentive Mechanism. FPL is also projecting to incur $57,360 in expenses for the licensing and maintenance of OATI WebTrader software.

Q. Please describe the costs that are included in FPL's projections for VOM expenses.

A. Consistent with Paragraph 15 of the 2016 Base Rate Settlement Agreement, FPL has included for recovery in its 2018 FCR factors, VOM expenses that reflect the netting of economy sales and purchases. As shown on Schedules E6 and E9 of Appendix II, FPL projects to sell 2,095,700 MWh and purchase 1,332,100 MWh of economy power. Therefore, applying FPL's VOM rate of $0.65/MWh, FPL projects to incur VOM expenses of $1,362,205 associated with its economy sales and to avoid ($865,865) with its economy purchases. FPL has included for recovery the net of these two figures, $496,340 (Schedule E2, Sum of Line Nos. 13 and 14), in its 2018 FCR factors.

<u>CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE COMMERCIAL OPERATION OF SOLAR PHOTOVOLTAIC ("PV") GENERATION</u>

Q. Please describe the PV generation that FPL will put into commercial operation during 2018.

A. The PV generation will consist of eight solar energy centers located at eight sites. The eight solar energy centers are sized to generate a total of 596 MW (nameplate capacity). Four of these solar energy centers ("the 2017 Project"), totaling 298 MW (nameplate capacity), are scheduled to go into service on January 1, 2018. These four sites consist of Coral Farms, Horizon, Wildflower, and Indian River. The remaining four solar energy centers ("the 2018 Project"), totaling 298 MW (nameplate capacity), are scheduled to go into service on March 1, 2018. These four sites consist of Loggerhead, Barefoot Bay, Hammock, and Blue Cypress.

Q. Will the operation of PV generation during 2018 result in fuel savings for FPL's customers?

A. Yes. For the January through December 2018 period, the operation of the 2017 Project is projected to result in fuel savings for FPL's customers of $20,098,304. For the March through December 2018 period, the operation of the 2018 Project is projected to result in fuel savings for FPL's customers of $18,548,736.

Q. How did FPL calculate the projected fuel savings associated with the operation of the 2017 and 2018 Projects?

A. FPL utilized its GenTrader model to quantify the fuel savings associated with the operation of the 2017 and 2018 Projects. This model is used to calculate the fuel costs that are included in FPL's projection filing. The same forecasted fuel prices and other assumptions that are reflected in the projection filing were used for analyzing the solar generation fuel savings. In order to calculate the fuel savings, FPL ran three separate production cost simulations, one with both the 2017 and 2018 Projects included ("the Base Case"), one with only the 2018 Project included, and one with only the 2017 Project included. A comparison of the total system fuel costs from the Base Case and the total system fuel costs with only the 2018 Project included, yielded the fuel savings for the 2017 Project. A comparison of the total system fuel costs from the Base Case and the total system fuel costs with only the 2017 Project included, yielded the fuel savings for the 2018 Project. In total, the three simulations showed that the fuel costs were $38,647,040 lower with the 2017 and 2018 Projects in service.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF MICHAEL KILEY

DOCKET NO. 20170001-EI

AUGUST 24, 2017

Q. Please state your name and address.

A. My name is Michael Kiley. My business address is 15430 Endeavor Drive, Jupiter, FL 33478.

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

A. I am employed by Florida Power & Light Company ("FPL") as Vice President of Organizational Effectiveness and Learning in the Nuclear Business Unit.

Q. Please describe your duties and responsibilities.

A. I am responsible for the Nuclear fleet functional areas of Security, Training, Nuclear Licensing and Regulatory Compliance, and Performance Improvement.

Q. Please describe your educational background and business experience in the nuclear industry.

A. I hold a Master of Business Administration degree from Southern New Hampshire University, and a Bachelor of Science degree in Marine Engineering from Massachusetts Maritime Academy. I also earned a Senior Reactor Operator License at Seabrook Nuclear Plant.

I have spent 30 years in the nuclear industry in increasingly responsible positions at NextEra Energy Resources ("NEER") and FPL including Control Room Operator to Plant General Manager at two separate NEER locations, to Site Vice President at Turkey Point, Vice President of Project Controls and Strategic Alliances to my current role of Vice President of Organizational Effectiveness and Learning.

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 2018 through December 2018. I am also supporting FPL's projected 2018 incremental plant security and Fukushima costs. Finally, I address 2017 outage events at FPL's nuclear units.

<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 2018 through December 2018.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2018 through December 2018.

A. FPL projects the nuclear units will burn 305,610,510 MMBtu of energy at a cost of $0.6102 per MMBtu for the period January 2018 through December 2018.

Projections by nuclear unit and by month are listed in Appendix II, on Schedule E-4, starting on page 17, which is attached as an exhibit to FPL witness Deaton's testimony.

Nuclear Plant Incremental Security Costs

Q. What is FPL's projection of incremental security costs at FPL's nuclear power plants for the period January 2018 through December 2018?

A. FPL projects that it will incur $36.2 million in incremental nuclear power plant security costs in 2018. The costs consist of $6.5 million of capital expenditures and $29.7 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 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, 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 2018 through December 2018?

A. FPL's current projection of Fukushima-related costs for 2018 is approximately $1.4 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 2018:

- FPL's share of costs incurred for equipment, storage, and transportation, to support the shared Regional Response Centers (a warehouse of off-site portable equipment shared by the industry).
- Severe Accident Management Guideline upgrades.
- Payment of NRC fees charged for NRC work-hours for review related to revised flooding integration assessment prepared in 2017 and for reviewing FPL's responses associated with the various regulatory orders and information requests.

2017 Unplanned Outage Events

Q. Has FPL experienced any unplanned outages at its St. Lucie plant in 2017?

A. Yes. In January 2017, Unit 1 was manually shut down to investigate a leak in the Reactor Coolant System (RCS).

Q. Please describe the circumstances related to the leak in the RCS.

A. During startup after the fall outage of 2016, the unit experienced a leak on the 1B2 Reactor Coolant Pump (RCP) lower seal heat exchanger tubing. Upon investigation, FPL determined the most probable cause was a deficiency in the lower seal heat exchanger design which allowed stresses that approached or exceeded the yield strength of the assembly tubing during torqueing of the Component Cooling Water flanges. This resulted in low stress high cycle fatigue failure of the weld joint.

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

A. FPL conducted repairs to the lower seal heat exchanger tubing to address the issue. Visual examinations on the remaining three reactor coolant pump seal coolers on Unit 1, and the four seal coolers on Unit 2 were performed with satisfactory results. Additionally, FPL revised procedures to reduce the required torque applied in future assembly tubing maintenance. Finally, FPL will perform further examinations during the next refueling outage to ensure there are no surface flaws in the affected areas.

Q. How many days was St. Lucie Unit 1 out of service due to this event?

A. The Unit 1 outage due to the RCS leak was approximately 7 days.

Q. Has FPL experienced any unplanned outages at its Turkey Point plants in 2017?

A. Yes. In March 2017, Unit 3 automatically shut down due to the loss of the 3A 4kV bus.

Q. What caused the loss of the 3A 4kV bus?

A. An electrical fault occurred in the Unit 3A switchgear room resulting in a loss of a safety-related electrical bus and a reactor trip. The system responded as designed. Based on the findings and tests performed, FPL concluded that the electrical fault was caused by carbon fibers from Thermo-lag material being installed in the 3A Switchgear Room. The carbon fibers entered cubicle A06 and created an electrical bridge between the buss bar and the wall of the 3AA06 cabinet which then caused the arc fault that initiated the event.

Q. What corrective actions have been initiated to address the loss of 3A 4kV bus event?

A. FPL repaired the Reactor Coil and associated Buss in the 3AA06 Cabinet of the 3A Switchgear room. FPL reviewed the Thermo-lag Installation procedure in effect at the time that the Thermo-lag material being installed in the 3A Switchgear Room and determined that it did not address the control of foreign material that may be produced from the installation process. FPL has revised the Thermo-lag Installation procedure to include precautions that were developed for the 4A switchgear room after the incident. FPL also revised its engineering design procedure so that it affirmatively prompts review of Safety Data Sheets for material being considered in a design, to determine if there are any hazards being introduced during installation and use of this material.

Q. Were there any other issues that contributed to the duration of the unplanned outage?

A. Yes. Prior to this 3A 4kV bus event, FPL was monitoring degraded performance of a Reactor Coolant Pump (RCP) seal. FPL replaced all RCP seals with Flowserve NX seals during the Fall 2015 outage as part of a Station Blackout Mitigation for Fukushima-related requirements. The cause of the seal degradation is still under investigation.

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

A. FPL replaced the 3A and 3B RCP seals. As a preventative measure, grounding rings were installed onto the motor shaft to stop the potential for stray current which may have caused pitting on the seal faces. Additionally, FPL has submitted a warranty claim with Flowserve for the RCP seals that were replaced in Unit 3 during the Fall 2015 outage. Any proceeds FPL may receive from this claim will be credited back through the Capacity Clause.

Q. How many days was Turkey Point Unit 3 out of service due to these events?

A. The Unit 3 outage due to the loss of 3A 4kV bus and 3A and 3B RCP seal malfunction was approximately 9 days. Unit 3 commenced the planned refueling outage after addressing these events.

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. 170001-EI

MARCH 15, 2017

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.

Q. Please summarize your educational background and professional experience.

A. I graduated from DePauw University with a Bachelor's degree in Industrial Psychology in 1991. I subsequently earned a Master of Business Administration from Pace University in New York in 1994. I am a Certified Public Accountant in the state of New York. Prior to joining FPL in 2009, I held various auditing positions at Price Waterhouse LLP and Pfizer Inc. From 1999 to 2009, I worked for Rinker Materials (acquired by Cemex in 2008) in various audit, accounting and development capacities. I have been in my current role at FPL since 2009 where I have responsibility for all Budgeting, Forecasting, Regulatory and Internal Controls activities for FPL's fossil generating assets. I have previously testified as a Generating Performance Incentive Factor ("GPIF") witness and since January 2013, I have also overseen the overall preparation and filing of GPIF documents including testimony, exhibits, audits and discovery.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to report actual 2016 performance for Equivalent Availability Factor ("EAF") and Average Net Operating Heat Rate ("ANOHR") for the eleven generating units used to determine the GPIF and to calculate the resulting GPIF reward. I have compared the performance of each unit to the revised targets approved in the final Commission Order No. PSC-15-0586-FOF-EI issued December 23, 2015, for the period January through December 2016, and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the result of these calculations: $19,320,088 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $9,656,036.

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

A. Yes. Exhibit CRR-1 shows the reward/penalty calculations. Page 1 of Exhibit CRR-1 is an index to the contents of the exhibit.

Q. **Please explain how the total GPIF reward/penalty amount was calculated in general terms.**

A. The steps involved in making this calculation are provided in Exhibit CRR-1. Page 2 provides the GPIF Reward/Penalty Table (Actual), which shows an overall GPIF performance point value of +2.4839, $19,320,088 in fuel savings and a GPIF reward of $9,656,036. Page 3 provides the calculation of the maximum allowed incentive dollars as approved by Commission Order No. PSC-13-0665-FOF-EI issued December 18, 2013. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each GPIF unit, the unit's performance indicators (EAF and ANOHR), the weighting factors, and the associated GPIF unit points.

Page 5 is the actual EAF and adjustments summary. This page, in columns 1 through 5, lists each of the eleven GPIF units, the actual outage factors and the actual EAF for each unit. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6. Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined by interpolating from the tables shown on pages 8 through 18. These tables are based on the targets and target ranges previously submitted to, and approved by, the Commission.

Continuing with Exhibit CRR-1, page 7 shows the adjustments to ANOHR. For each GPIF unit it shows, in columns 2 through 4, the target heat rate formula, and the actual net output factor ("NOF") and ANOHR for all units. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment provides a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points as determined by interpolating from the tables shown on pages 8 through 18. These tables are based on the targets and target ranges submitted to, and approved by, the Commission.

Q. Please explain the primary reason why FPL will receive a reward under the GPIF for the January through December 2016 period.

A. The primary reason that FPL will receive a reward for the period is that adjusted actual EAFs for eight out of the eleven GPIF units were better than their targets. In addition, four out of the eleven GPIF units operated with an adjusted actual ANOHR that was below the ±75 Btu/kWh dead band.

Q. Please summarize each nuclear unit's performance as it relates to the EAF of the units.

A. St. Lucie Unit 1 operated at an adjusted actual EAF of 83.2%, compared to its target of 85.1%. This results in -6.33 points, which corresponds to a GPIF penalty of $2,138,486.

St. Lucie Unit 2 operated at an adjusted actual EAF of 100.0%, compared to its target of 92.5%. This results in +10.0 points, which corresponds to a GPIF reward of $3,234,358.

Turkey Point Unit 3 operated at an adjusted actual EAF of 98.7% compared to its target of 90.8%. This results in +10.0 points, which corresponds to a GPIF reward of $3,560,904.

Turkey Point Unit 4 operated at an adjusted actual EAF of 90.1% compared to its target of 84.6%. This results in +10.0 points, which corresponds to a GPIF reward of $2,853,388.

In total, the combined nuclear units' EAF performance resulted in a GPIF reward of $7,510,164.

Q. Please summarize each nuclear unit's performance as it relates to unit's ANOHR.

A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,432 Btu/kWh compared to its target of 10,471 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The St. Lucie Unit 2 adjusted actual ANOHR is 10,273 Btu/kWh compared to its target of 10,270 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The Turkey Point Unit 3 adjusted actual ANOHR is 10,991 Btu/kWh compared to its target of 11,102 Btu/kWh. This ANOHR is better than the ±75 Btu/kWh dead band around the projected target. This results in +1.9 points, which corresponds to a GPIF reward of $121,288.

Turkey Point Unit 4 adjusted actual ANOHR results in 10,885 Btu/kWh compared to its target of 11,082 Btu/kWh. This ANOHR is better than the ±75 Btu/kWh dead band around the projected target. This results in +9.04 points, which corresponds to a GPIF reward of $389,911.

In total, the combined nuclear units' heat rate performance resulted in a GPIF reward of $511,199.

Q. What is the total GPIF reward for FPL's nuclear units?

A. $8,021,363.

Q. Please summarize the performance of FPL's fossil units.

A. Regarding EAF performance, five of the seven fossil generating units performed better than their availability targets resulting in a combined reward of $4,423,530 while the other two performed worse than their availability targets resulting in a combined penalty of $2,325,473. Thus, the total fossil units' availability performance results in a net GPIF reward of $2,098,057.

Regarding ANOHR, two out of the seven fossil units operated with an ANOHR that was below the ±75 Btu/kWh dead band, resulting in a combined reward of $1,065,939. Out of the remaining five fossil units, three operated with ANOHRs that were within the ±75 Btu/kWh dead band so there were no incentive rewards or penalties while the other two operated above the dead band so they received a combined penalty of $1,529,323. Thus, the total fossil units' heat rate performance results in a net GPIF penalty of $463,384.

Q. What is the total GPIF reward/penalty for FPL's fossil units?

A. The net GPIF availability performance reward of $2,098,057 plus the net GPIF heat rate performance penalty of $463,384 results in a total GPIF reward for FPL's fossil units of $1,634,673.

Q. To recap, what is the total GPIF result for the period January through December 2016?

A. The total GPIF result for the period January through December 2016 is $19,320,088 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $9,656,036.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20170001-EI

AUGUST 24, 2017

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) as 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. What is the purpose of your testimony?

A. The purpose of my testimony is to 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 2018 and revised 2017 targets reflecting the effects of the Indiantown Cogeneration L.P. (Indiantown) transaction (Indiantown Transaction) as approved in Order No. PSC-16-0506-FOF-EI, issued in Docket No. 160154-EI on November 2, 2016.

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

A. Yes, I am sponsoring Exhibits CRR-2 and CRR-3. Exhibit CRR-2 supports the development of the 2018 GPIF EAF and ANOHR targets. Exhibit CRR-3 supports the development of the 2017 GPIF EAF and ANOHR targets, including the Indiantown Transaction. The first page of each exhibit is an index to its contents. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. Please summarize the 2018 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 2018, FPL projects a weighted system equivalent planned outage factor of 7.4% and a weighted system equivalent unplanned outage factor of 6.7%, which yield a weighted system EAF target of 85.9%. The targets for this period reflect planned refuelings for St. Lucie Units 1 and 2 and Turkey Point Unit 3. FPL also projects a weighted system ANOHR target of 7,311 Btu/kWh for the period January through December 2018. 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-2, pages 6 and 7, contains the information summarizing the individual targets and ranges for EAF and ANOHR for each of the twelve generating units that FPL proposes to be considered as GPIF units for the period January through December 2018. All of these targets have been derived utilizing the accepted methodologies adopted in the GPIF Manual.

Q. Please summarize FPL's methodology for determining EAF 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 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 are responsible for 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 twelve units which FPL proposes to use for the period January through December 2018 represent the top 81.1% of the total forecasted system net generation for this period excluding the Port Everglades Next Generation Clean Energy Center. This unit came into service in 2016 and was excluded from the GPIF calculation because there is insufficient historical data to include it. Consistent with the GPIF Manual, this unit will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2018 EAF and ANOHR performance targets as shown on Exhibit CRR-2 represent reasonable levels of generation availability and efficiency?

A. Yes, they do.

Q. Has FPL performed a recalculation of the 2017 GPIF EAF and ANOHR targets to reflect the effects of the Indiantown Transaction?

A. Yes it has. At the time that the 2017 targets were filed last year, the Commission had not yet approved the Indiantown Transaction. Thereafter, the transaction was approved and the Indiantown unit was shut down. The recalculation reflects the effects of the Indiantown Transaction, including shutting down the unit.

Q. Did the recalculated EAF and ANOHR targets for January 2017 through December 2017 change due to the Indiantown Transaction?

A. The recalculated 2017 weighted system EAF target did not change from the prior 2017 weighted system EAF target; however, the recalculated weighted system ANOHR target dropped slightly to 7,263 Btu/kWh for the period January through December 2017 from the prior 2017 weighted system ANOHR target.

Q. What are the appropriate adjustments to FPL's 2017 GPIF targets and ranges to reflect the effects of the Indiantown Transaction?

A. The appropriate 2017 GPIF targets and ranges are shown in Exhibit CRR-3.

Q. Do FPL's 2017 recalculated EAF and ANOHR performance targets as shown on Exhibit CRR-3 represent reasonable levels of generation availability and efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF LIZ FUENTES

DOCKET NO. 20170001-EI

AUGUST 24, 2017

Q. Please state your name and business address.

A. My name is Liz Fuentes, and my business address is Florida Power & Light Company, 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" or the "Company") as Senior Director, Regulatory Accounting.

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

A. I am responsible for planning, guidance, and management of all regulatory accounting activities for FPL. In this role, I manage the accounting of FPL's cost recovery clauses and ensure that the Company's financial books and records comply with multi-jurisdictional regulatory accounting requirements. In addition, I manage the preparation and filing of FPL's monthly earnings surveillance report with the Florida Public Service Commission ("FPSC" or "Commission").

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Florida in 1999 with a Bachelor of Science Degree in Accounting. That same year, I was employed by FPL. During my tenure at the Company, I have held various accounting and regulatory positions with the majority of my career focused in regulatory accounting and ratemaking. I am a Certified Public Accountant ("CPA") licensed in the Commonwealth of Virginia and a member of the American Institute of CPAs.

Q. What is the purpose of your testimony?

A. The purpose of my direct testimony is to present the computation of the incremental jurisdictional annualized base revenue requirements associated with the Solar Base Rate Adjustments ("SoBRA") related to the solar photovoltaic projects expected to be placed in service in 2017 and 2018 (the "2017 Project" and the "2018 Project"). In addition, I will explain the appropriate regulatory treatment for items such as investment tax credits ("ITC") associated with the solar assets and the depreciation-related accumulated deferred income taxes ("ADIT") proration adjustment which is required by Internal Revenue Code ("IRC") Treasury Regulation §1.167(1)-1(h)(6). The revenue requirements for these SoBRAs are based on the first 12 months of operations of the Projects. FPL is authorized to seek recovery of a SoBRA pursuant to the Stipulation and Settlement Agreement reached in FPL's most recent rate case and approved by the Commission in Order No. PSC-16-0560-AS-EI, Docket Nos. 160021-EI, 160061-EI, 160062-EI, and

160088-EI ("2016 Settlement Agreement").

Q. Please summarize your testimony.

A. The annualized jurisdictional revenue requirements for the first 12 months of operations related to the 2017 Project and 2018 Project are $60.5 million and $59.9 million, respectively. These calculations are largely based on the estimated capital expenditures presented by FPL witness Brannen in his supplemental testimony filed on August 2, 2017.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- LF-1 – SoBRA Revenue Requirement Calculation – Effective date January 1, 2018.
- LF-2 – SoBRA Revenue Requirement Calculation – Effective date March 1, 2018.

Q. Please briefly describe the basis for the SoBRA Projects' revenue requirements.

A. Pursuant to the 2016 Settlement Agreement, FPL is authorized to recover the revenue requirements based on the first 12 months of operations of the Projects. If approved, the first SoBRA is expected to be implemented on January 1, 2018; and the second SoBRA is expected to be implemented on March 1, 2018.

Q. What is the amount of FPL's requested SoBRA for the 2017 Project?

A. As reflected on page 1 of Exhibit LF-1, the amount of FPL's requested base revenue increase for the first 12 months of operations of the 2017 Project is

$60.5 million.

Q. What is the amount of FPL's requested SoBRA for the 2018 Project?

A. As reflected on page 1 of Exhibit LF-2, the amount of FPL's requested base revenue increase for the first 12 months of operations of the 2018 Project is $59.9 million.

Q. Is the revenue requirement calculation for each Project calculated in the same manner?

A. Yes.

Q. Is the revenue requirement calculation methodology for the Projects similar to other generation base rate adjustments approved by the FPSC?

A. Yes. The SoBRA revenue requirement calculation methodology is similar to the methodologies approved by the FPSC for FPL's generation base rate adjustments ("GBRA") for Turkey Point Unit 5 and West County Energy Center Units 1 and 2 in Order No. PSC-05-0902-S-EI, West County Energy Center Unit 3 in Order No. PSC-11-0089-S-EI, and the modernization projects at Canaveral, Riviera Beach, and Port Everglades in Order No. PSC-13-0023-S-EI. In addition, it is also consistent with the recently approved 2019 Okeechobee Limited Scope Adjustment ("Okeechobee LSA") in FPL's 2016 Settlement Agreement.

Q. Please describe inputs utilized to compute the revenue requirements for each SoBRA.

A. The revenue requirement computations for each SoBRA are based on the following inputs:

- Capital expenditures: These are based on the Company's estimated capital expenditures, including accumulated funds used during construction. FPL witness Brannen describes the capital costs for each of the Projects in his supplemental testimony filed on August 2, 2017.
- Depreciation rates: The depreciation rates utilized to compute depreciation expense and related accumulated depreciation for solar generation and transmission plant are based on Exhibit D of FPL's 2016 Settlement Agreement.
- Operating expenses: These are based on the Company's estimated operating expenses for the first 12 months of operations.
- Incremental cost of capital: As reflected in paragraph 10(f) of FPL's 2016 Settlement Agreement, the Company is required to use a 10.55% return on common equity and an incremental capital structure consistent with the approach authorized for the Okeechobee LSA, adjusted to reflect the inclusion of ITCs on a normalized basis. Therefore, ADIT are not included in the incremental capital structure, and instead, as described below, ADIT are included as a component of rate base. FPL used the equity ratio and long-term debt rate set forth on page 8 of Exhibit KO-20 (FPL witness Ousdahl) from FPL's 2016 rate case filing, consistent with the 2018 Subsequent Year base rate change approved in the 2016 Settlement Agreement. FPL also incorporated an estimate for unamortized ITCs. The incremental cost of capital calculation for the 2017 Project is reflected on page 3 of Exhibit LF-1, and the calculation for

the 2018 Project is reflected on page 3 of Exhibit LF-2.

- Accumulated deferred income taxes: As described above, ADIT are included as a component of rate base, which is consistent with the treatment in FPL's prior GBRAs and the treatment most recently approved for FPL's 2019 Okeechobee LSA. The ADIT for the 2017 and 2018 Projects primarily reflects the timing difference between book and tax depreciation, specifically bonus tax depreciation, over the life of the assets. In addition, FPL is required to comply with the IRC Treasury Regulation §1.167(1)-1(h)(6) and utilize a proration formula to compute the depreciation-related ADIT balance to be included for ratemaking purposes when a forecasted test period is utilized to set rates. This proration adjustment was utilized during the Company's most recent base rate filing for the calculated increase in base rates for the 2017 Test Year, 2018 Subsequent Year, and the 2019 Okeechobee LSA. The ADIT proration adjustment for the 2017 Project is reflected on page 5 of Exhibit LF-1, and the 2018 Project is reflected on page 5 of Exhibit LF-2.

Q. Please describe the ITCs associated with the revenue requirement calculation for the 2017 and 2018 Solar Projects.

A. In accordance with Section 48 of the IRC, the Company will record an ITC of approximately $104.2 million and $106.5 million for the 2017 Project and 2018 Project, respectively. These amounts represent 30% of the qualified capital spending associated with each solar investment upon the in-service date of each site. FPL will amortize the ITCs as a reduction to tax expense over the life of each unit, which is estimated to be approximately 30 years.

Q. How will the unamortized ITCs be reflected in the incremental cost of capital calculation?

A. As described above and reflected on page 3 of Exhibits LF-1 and LF-2, the unamortized balance of the ITCs will be reflected as a component of capital structure and have a blended debt and equity cost rate. This treatment is consistent with how ITCs are currently reflected in FPL's Earnings Surveillance Reports for investments that have produced ITCs. FPL's methodology to calculate the ITC cost rate was reviewed and approved by this Commission in Order No. PSC-10-0153-FOF-EI, Docket Nos. 080677-EI, 090130-EI.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TIFFANY C. COHEN

DOCKET NO. 20170001-EI

AUGUST 24, 2017

Q. Please state your name and business address.

A. My name is Tiffany C. Cohen, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as the Senior Manager of Rate Development in the Rates & Tariffs Department.

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

A. I am responsible for developing the appropriate rate design for all electric rates and charges. Additionally, I am responsible for proposing and administering the tariffs needed to implement those rates and charges.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science Degree in Commerce and Business Administration, with a major in Accounting from the University of Alabama. I obtained a Master of Business Administration from the University of New Orleans. I am also a Certified Public Accountant. I joined FPL in 2008 as the Manager of the Nuclear Cost Recovery Clause. I assumed my current position in June 2013. Prior to joining FPL, I was employed at Duke Energy for five years, where I held a variety of positions in the Rates & Regulatory Division, including managing rate cases, Corporate Risk Management, and Internal Audit departments. Prior to joining Duke Energy, I was employed at KPMG, LLP.

Q. What is the purpose of your testimony?

A. My testimony presents the Solar Base Rate Adjustment ("SoBRA") factor and the corresponding changes to base rates needed to recover the annual revenue requirements associated with the Company's universal solar energy centers that are currently being constructed and expected to enter commercial operation by January 1, 2018 and March 1, 2018 ("2017 Project" and "2018 Project," respectively).

Q. Are you sponsoring any exhibits in this docket that were prepared by you or under your supervision?

A. Yes. I am sponsoring the following exhibits:

- TCC-1 SoBRA Factor Calculation;
- TCC-2 Projected Retail Base Revenues;
- TCC-3 Summary of Tariff Changes for January 1, 2018;
- TCC-4 Summary of Tariff Changes for March 1, 2018; and
- TCC-5 Typical Bill Estimates.

Q. Please explain the calculation of the SoBRA factors and the purpose they serve.

A. I have calculated the SoBRA factors as required by FPL's 2016 Settlement Agreement ("Settlement Agreement"), approved by the Florida Public Service Commission ("Commission") in Order No. PSC-16-0560-AS-EI. The SoBRA factors are based on the ratio of (1) the Company's jurisdictional revenue requirements for each Project and (2) the forecasted retail base revenue from electricity sales for the first twelve months of each rate year, beginning January 1, 2018 for the 2017 Project and March 1, 2018 for the 2018 Project. Application of the SoBRA factors to the Company's January 1, 2018 and March 1, 2018 base rates will provide the Company with sufficient revenue to recover the costs associated with the construction and operation of the 2017 and 2018 Projects. The calculation and resulting factor of 0.937% for the 2017 Project, and 0.919% for the 2018 Project, are shown in Exhibit TCC-1, page 1 of 1.

Q. Do you have an exhibit that provides the forecasted retail base revenue for each projected 12-month period?

A. Yes. Exhibit TCC-2, pages 1 and 2, reflects the forecasted retail base revenue from the sales of electricity for all customer classes for each projected 12-month period. Forecasted retail base revenues from the sales of electricity include customer, demand and energy charge revenues, base revenues recovered through the Energy Conservation Cost Recovery Clause for the Commercial/Industrial Load Control Program ("CILC") and Commercial/Industrial Demand Reduction Rider ("CDR") credits, and non-clause recoverable credits (*e.g.*, transformation rider credits and curtailable service credits). Thus, all the charges subject to the SoBRA factors are included in these revenue figures. In addition, unbilled retail base revenue is included in total retail base revenue from the sales of electricity in order to account for the collection lag resulting from the billing cycle. The total retail base revenues from the sale of electricity for the twelve months beginning January 1, 2018 and March 1, 2018 are projected to be $6,458.109 million and $6,518.299 million respectively, shown on Exhibit TCC-2, pages 1 and 2.

Q. **Do you have an exhibit that provides a summary of the retail base rates to become effective for meter readings made on and after January 1, 2018 and March 1, 2018?**

A. Yes. Exhibit TCC-3 provides a summary of the base rates proposed to become effective for meter readings made on and after January 1, 2018, shown in column 5 of Exhibit TCC-3, pages 1-25.

Exhibit TCC-4, provides a summary of the base rates proposed to become effective for meter readings made on and after March 1, 2018, shown in column 4 of Exhibit TCC-4, pages 1-25.

If the SoBRA and the associated charges are approved for both Projects, the Company will submit revised tariff sheets reflecting the Commission-approved charges.

Q. **Please explain how the Company will notify the Commission of the 2017 and 2018 Projects' commercial operation date?**

A. The Company will submit to the Commission a letter that declares the commercial operation date and time. SoBRA base rate changes will become effective only on or after the commercial operation date for each Project.

Q. Please explain how these proposed changes in the base rates will impact FPL's customers' bills and how will they compare to other utilities nationally and in Florida.

A. Exhibit TCC-5 reflects base rate changes as approved in Docket No. 160021 to become effective on January 1, 2018, and proposed SoBRA base rate increases on January 1, 2018 and March 1, 2018. The exhibit also reflects proposed fuel and other clause rates for 2018 including the proposed reduction in fuel expenses associated with the Projects.

FPL projects that the March 1, 2018 typical residential bill of $99.75 will remain 25% below the national average (as of January 2017), 15% below the state average (as of June 2017), and will remain among the lowest in the state of Florida.

Q. Will customers receive a credit if the actual capital expenditures for the 2017 and 2018 Projects are less than the projected costs used to develop these initial SoBRA factors?

A. Yes. As more fully described in Section 10(g) of the Settlement Agreement, customers will receive a one-time credit through the Capacity Cost Recovery Clause to reflect the difference between the Project's actual and projected capital expenditures. This is identical to the mechanism FPL employed to true-up the capital expenditures associated with the Cape Canaveral and Port Everglades Energy Centers.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 170001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2016 Final True-Up)
on behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis Young, 1641 Worthington Road, Suite 220, West Palm Beach, Fl 33409.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of the final remaining true-up amounts for the period January 2016 through December 2016.

Q. Have you included any exhibits to support your testimony?

A. Yes. Exhibit________ (CDY-1) consists of Schedules A, C1 and E1-B for the Consolidated Electric Division. These schedules were prepared from the records of the company.

Q. What has FPUC calculated as the final remaining true-up amounts for the period January 2016 through December 2016?

A. For the Consolidated Electric Division the final remaining true-up amount is an under recovery of $2,415,898.

Q. How was this amount calculated?

A. It is the difference between the actual end of period true-up amount for the January through December 2016 period and the total true-up amount to be collected or refunded during the January - December 2017 period.

Q. What was the actual end of period true-up amount for January - December 2016?

A. For the Consolidated Electric Division it was $3,705,790 under recovery.

Q. What was the Commission-approved amount to be collected or refunded during the January – December 2017 period?

A. A consolidated under-recovery of $1,289,892 to be collected.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20170001-EI: Fuel and purchased power cost recovery clause

Direct Testimony (Actual/Estimated True-Up) of Michael Cassel

On Behalf of

Florida Public Utilities Company

July 27, 2017

Q. Please state your name and business address.

A. My name is Michael Cassel. My business address is 1750 S. 14th Street, Suite 200, Fernandina Beach, Florida 32034.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company")

Q. Describe briefly your education and relevant professional background.

A. I received a Bachelor of Science Degree in Accounting from Delaware State University in Dover, Delaware in 1996. I was hired by Chesapeake Utilities Corporation (CUC) as a Senior Regulatory Analyst in March 2008. As a Senior Regulatory Analyst, I was primarily involved in the areas of gas cost recovery, rate of return analysis, and budgeting for the CUC's Delaware and Maryland natural gas distribution companies. In 2010, I moved to Florida in the role of Senior Tax Accountant for CUC's Florida business units. Since that time, I have held various management roles including Manager of the Back Office in 2011, Director of Business Management in 2012. I am currently the Director of Regulatory and Governmental Affairs for CUC's Florida business units. My responsibilities include directing the regulatory and governmental affairs activity for CUC in Florida including regulatory analysis, and reporting and filings before the Florida Public Service Commission (FPSC). Prior to joining Chesapeake, I was employed by J.P. Morgan Chase & Company, Inc. from 2006 to 2008 as a Financial Manager in their card finance group. My primary responsibility in this position was the development of client specific financial models and profit loss statements. I was also employed by Computer Sciences Corporation as a Senior Finance Manager from 1999 to 2006. In this position, I was responsible for the financial operation of the company's chemical, oil and natural resources business. This included forecasting, financial close and reporting responsibility, as well as representing Computer Sciences Corporation's financial interests in contract/service negotiations with existing and potential clients. From 1996 to 1999 I was employed by J.P. Morgan, Inc., where I had various accounting/finance responsibilities for the firm's private banking clientele.

Q. Have you previously testified in this Docket?

A. I have previously provided pre-filed written testimony in the Commission's Fuel Clause proceeding.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the basis for the Company's computations made in preparation of the schedules being submitted in support of the calculation for the levelized fuel adjustment factor for January 2018 – December 2018.

Q. Were the schedules filed by the Company completed by you or under your direction?

A. The schedules were completed under my direct supervision and review.

Q. Which of the Staff's schedules is the Company providing in support of this filing?

A. I am attaching Schedules E1-A, E1-B, and E1-B1 as my Exhibit MC-1. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2017 – December 2017 based on 6 Months Actual and 6 Months Estimated data.

Q. What was the final remaining true-up amount for the period January 2016 – December 2016?

A. The final remaining true-up amount was an under-recovery of $2,415,898.

Q. What is the estimated true-up amount for the period January 2017 – December 2017?

A. The estimated true-up amount is an under-recovery of $975,518.

Q. What is the total true-up amount to be collected, or refunded during January 2018 – December 2018?

A. At the end of December 2017, based on six months actual and six months estimated, the Company estimates it will under-recover $3,391,416 in purchased power costs, which will be collected from January 2018 – December 2018.

Q. Has the Company included any amounts in recovery of the Florida Power & Light ("FPL") interconnect project?

A. Because of the Florida Supreme Court's decision No. SC 16-141, issued March 16, 2017, overturning the Commission's decision in Order No. PSC-15-0586-FOF-EI to allow the Company to recover the depreciation expense, taxes other than income taxes and a return on investment for the FPL Interconnect through the Company's fuel cost recovery clause, the Company has removed the amounts associated with this project from the calculations included in the attached schedules. The Company had originally computed the annual costs associated with this project to be $107,333 in its 2016 Fuel Projection filing and $120,000 in its 2017 Fuel Projection filing.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20170001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2018 Projection Testimony of
Michael Cassel
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Michael Cassel and my business address is 1750 S. 14th Street, Suite 200, Fernandina Beach, Florida 32034

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company")

Q. Could you give a brief description of your background and business experience?

A. I received a Bachelor of Science Degree in Accounting from Delaware State University in Dover, Delaware in 1996. I was hired by Chesapeake Utilities Corporation (CUC) as a Senior Regulatory Analyst in March 2008. As a Senior Regulatory Analyst, I was primarily involved in the areas of gas cost recovery, rate of return analysis, and budgeting for the CUC's Delaware and Maryland natural gas distribution companies. In 2010, I moved to Florida in the role of Senior Tax Accountant for CUC's Florida business units. Since that time, I have held various management roles including Manager of the Back Office in 2011 and Director of Business Management in 2012. I am currently the Director of Regulatory and Governmental Affairs for CUC's Florida business units. My responsibilities include directing the regulatory and governmental affairs activity for CUC in Florida including regulatory analysis, and reporting and filings before the Florida Public Service Commission (FPSC). Prior to joining Chesapeake, I was employed by J.P. Morgan Chase & Company, Inc. from 2006 to 2008 as a Financial Manager in their card finance group. My primary responsibility in this position was the development of client-specific financial models and profit loss statements. I was also employed by Computer Sciences Corporation as a Senior Finance Manager from 1999 to 2006. In this position, I was responsible for the financial operation of the company's chemical, oil and natural resources business. This included forecasting, financial close and reporting responsibility, as well as representing Computer Sciences Corporation's financial interests in contract/service negotiations with existing and potential clients. From 1996 to 1999 I was employed by J.P. Morgan, Inc. where I had various accounting/finance responsibilities for the firm's private banking clientele.

Q. Have you previously testified in this Docket?

A. Yes, I have provided written testimony in this proceeding previously.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the basis for the computations that were made in the preparation of the various Schedules that the Company has submitted in support of the January 2018 - December 2018 fuel cost recovery adjustments for its consolidated electric divisions. In addition, I will explain the projected differences between the revenues collected under the levelized fuel adjustment and the purchased power costs allowed in developing the levelized fuel adjustment for the period January 2017 – December 2017 and to establish a "true-up" amount to be collected or refunded during January 2018 - December 2018.

Q. Were the schedules filed by the Company completed by you or under your direct supervision?

A. Yes, they were completed under my direct supervision and review.

Q. Is FPUC providing the required schedules with this filing?

A. Yes. Included with this filing are Consolidated Electric Schedules E1, E1A, E2, E7, E8, and E10. These schedules are included in my Exhibit MC-2, which is appended to my testimony.

Q. Did you include costs in addition to the costs specific to purchased fuel in the calculations of your true-up and projected amounts?

A. Yes, included with our fuel and purchased power costs are charges for contracted consultants and legal services that are directly fuel-related and appropriate for recovery in the fuel clause. Mr. Cutshaw addresses these projects more specifically in his testimony.

Q. Please explain how these costs were determined to be recoverable under the fuel clause?

A. Consistent with the Commission's policy set forth in Order No. 14546, issued in Docket No. 850001-EI-B, on July 8, 1985, the other costs included in the fuel clause are directly related to fuel, have not been recovered through base rates.

Specifically, consistent with item 10 of Order 14546, the costs the Company has included are fuel-related costs that were not anticipated or included in the cost levels used to establish the current base rates. To be clear, these costs are not tied to the Company's internal staff involvement in fuel and purchased power procurement and administration. Instead, these costs are associated with external contracts which consequently, tend to be more volatile depending upon the issue. Similar expenses paid to Christensen and Associates associated with the design for a Request for Proposals of Fuel costs, and the evaluation of those responses, were deemed appropriate for recovery by FPUC through the fuel clause in Order No. PSC-05-1252-FOF-EI, Item II E, issued in Docket No. 050001-EI. Additionally, in more recent Docket Nos. 20120001-EI, 20130001-EI, 20140001-EI, 20150001-EI, 20160001-EI and 20170001-EI, the Commission determined that many of the costs associated with the legal and consulting work incurred by the Company as fuel related, particularly those costs related to the purchase power agreement review and analysis, were recoverable under the fuel clause. As the Commission has recognized time and again, the Company simply does not have the internal resources to pursue projects and initiatives designed to produce fuel savings without engaging outside assistance for project analytics and due diligence, as well as negotiation and contract development expertise.

Likewise, the Company believes that the costs addressed herein are appropriate for recovery through the fuel clause.

Q. Please explain what are the costs outside of purchased fuel costs included in the 2017 true-up for Florida Public Utilities Company?

A. Florida Public Utilities engaged Sterling Energy Services, LLC. ("Sterling") Christensen Associates Energy, LLC ("Christensen"), Locke Lord, LLP ("Lord") and Pierpont and McClelland ("Pierpont") for assistance in the development and enactment of projects/programs designed to reduce their fuel rates to its customers. The associated legal and consulting costs, included in the rate calculation of the Company's 2018 Projection factors, were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

More specifically, Pierpont has been engaged to perform analysis and provide consulting services for FPUC as it relates to the structuring of, and operation under, the Company's power purchase agreements with the purpose of identifying measures that will minimize cost increases and/or provide opportunities for cost reductions. Lord is a law firm with particular expertise in the regulatory requirements of the Federal Energy Regulatory Commission. Attorneys with the firm have provided legal guidance and oversight regarding the contracts and regulatory requirements for generation and transmission-related issues for the Northeast Florida Division. The Company's in-house experience in these areas is limited; thus, without this outside assistance, the Company's ability to pursue potential fuel savings opportunities would be limited, as would its ability properly evaluate proposals to meet our generation and transmission needs and ensure compliance with federal regulatory requirements.

Sterling and Christensen have been hired to assist the Company in the most cost-effective means of incorporating additional energy sources, such as power available from certain industrial customers, including customers with Combined Heat and Power (CHP) capability, to further reduce the overall purchased power impact to all FPUC customers. And, again, these costs are consistent with the standard set forth in Order No. 14546 in that they are incurred in the pursuit of fuel and purchased power savings for our customers and are not otherwise being recovered through the Company's base rates. The Company intends to continue to engage legal and consulting assistance as it explores additional fuel related savings options including other CHP opportunities and solar/photovoltaic opportunities.

<u>Summary Rates</u>

Q. What are the final remaining true-up amounts for the period January – December 2016 for both Divisions?

A. The final remaining consolidated true-up amount was an under-recovery of $2,415,898.

Q. **What are the estimated true-up amounts for the period of January – December 2017?**

A. There is an estimated consolidated under-recovery of $975,518.

Q. **Please address the calculation of the total true-up amount to be collected or refunded during the January - December 2018 year?**

A. The Company has determined that at the end of December 2017, based on six months actual and six months estimated, we will have a consolidated electric under-recovery of $3,391,416.

Q. **What will the total consolidated fuel adjustment factor, excluding demand cost recovery, be for the consolidated electric division for the period?**

A. The total fuel adjustment factor as shown on line 43, Schedule E-1 is 6.506¢ per KWH.

Q. **Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2018 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier.**

A. As shown on consolidated Schedule E-10 in Composite Exhibit Number MC-2, a residential customer using 1,000 KWH will pay $131.10. This is a decrease of $7.52 under the previous period.

Q. **Does this conclude your testimony?**

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20170001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2018 Projection Testimony of P. Mark Cutshaw
On Behalf of
Florida Public Utilities Company

Q. **Please state your name and business address.**

A. My name is P. Mark Cutshaw, 1750 South 14th Street, Fernandina Beach, Florida 32034.

Q. **By whom are you employed?**

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company").

Q. **Could you give a brief description of your background and business experience?**

A. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began my career with Mississippi Power Company in June 1982. I spent 9 years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various Company locations. I joined FPUC in 1991 as Division Manager in our Northwest Florida Division and have since worked extensively in both the Northwest Florida and Northeast Florida Divisions. Since joining FPUC, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and Northwest Florida Divisions. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the Commission as well as other regulatory issues. During 2015 I moved into my current role as Director, Business Development and Generation.

Q. Have you previously testified in this Docket?

A. Yes, I've provided testimony in a variety of Commission proceedings, including the Company's 2014 rate case, addressed in Docket No. 140025-EI. Most recently, I provided written, pre-filed testimony in Docket No. 160001-EI, the Commission's regular fuel cost recovery proceeding, and also provided both pre-filed and live testimony the prior year, in Docket No. 150001-EI, regarding the Company's interconnection project with Florida Power & Light Company ("FPL"), which is also the subject of my testimony in this proceeding.

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

A. My direct testimony addresses several aspects of the purchased power cost for our FPUC electric customers. This includes activities to investigate potential avenues for reducing our purchase power costs, construction of a transmission line interconnection with FPL, execution of the new purchased power agreement with FPL, generation supply located on Amelia Island and investigation into the deployment of solar and battery storage assets.

Q. Has the Company investigated means to reduce costs for its customers in its consolidated electric divisions?

A. Yes. The Company continues to seek opportunities to engage base load providers for both electric divisions in discussions for an arrangement that would be more beneficial for the FPUC customers. Since 2007, when purchased power rates began to increase significantly from both providers, FPUC has been very assertive in challenging each cost determination performed by Jacksonville Energy Authority ("JEA") and Southern Company/Gulf Power (Gulf) that resulted in an increase to the purchased power rate. These very focused and steady efforts have mitigated the rate of increase in purchased power costs for FPUC and its customers. In January 2011, the Company was also successful in reaching an agreement with Gulf for an Amendment to the Company's purchased power contract with Gulf, which resulted in reduced costs to customers in its Northwest Florida Division. These same focused and steady efforts are continuing today and have resulted in a reduced rate of increase in fuel costs for FPUC and its customers.

The Company also continues to investigate other opportunities to reduce purchased power costs, including the contractual relationships with other wholesale power suppliers. As a result of this ongoing investigation into new opportunities, relationships were developed with other suppliers, informal studies of generation and transmission capacity arrangements were reviewed and contract possibilities were discussed. Although realization of some of these opportunities was not possible until the expiration of the existing contracts, the information gathered provided FPUC with invaluable resources that will enhance the Company's ability to achieve further savings in the next purchased power agreements.

Q. **What opportunities has the Company implemented with the intent of reducing costs for its customers in its consolidated electric divisions?**

A. The two most significant opportunities employed during this year are the construction of a 138 KV transmission line interconnection with Florida Power & Light (FPL) and a new purchased power agreement with FPL that will be effective January 1, 2018. Also, Eight Flags Energy LLC (Eight Flags) is continuing to provide reasonably priced, reliable, on-island generation and has recently completed one year in service with excellent availability and efficiency ratings.

Q. **Can you provide background on the transmission interconnect project with FPL?**

A. Yes. This is a significant project for FPUC, one that the Company has embarked upon specifically because we anticipated that it would directly improve our ability to negotiate increased savings for our customers in our next purchased power agreement, as well as improve the system reliability in our Northeast Florida Division. Historically, FPUC's ability to secure competitive wholesale power quotations was hindered by the limitation on the transmission interconnections providing power to FPUC's Northeast Florida Division (Amelia Island).

At present, the FPUC 138 KV transmission line is directly connected to the JEA 138 KV transmission system. Extending from the current interconnection with JEA, the FPUC 138 KV transmission line is a dual circuit, single pole line, which includes several miles of line located in relatively inaccessible marshy areas. This transmission line serves as the only off-island power supply to Amelia Island. In order to help mitigate the issues for upcoming wholesale power proposals, FPUC proposed an interconnection with the FPL transmission system, which is located in very close proximity to the existing FPUC transmission system. Not only will this additional interconnection provide access to more competitive wholesale power options, this will provide much needed redundancy to the power supply on Amelia Island which will have a positive impact on the overall system reliability.

Q. **Can you provide an update on the transmission interconnect project with FPL?**

A. Yes. The FPUC-owned 138 KV transmission line is located approximately 750 feet (0.14 miles) from the FPL O'Neil Substation and runs in the existing right-of-way along with the FPL 230 KV transmission line. Originally, the proposed construction was to include the construction of a new FPL substation in which the necessary transmission and system protection equipment was to be placed in order to allow for the interconnection of the FPUC 138 KV transmission line. The FPUC 138 KV transmission was to be re-routed into the new FPL 230/138 KV substation. However, during the planning process, unexpected local opposition was raised based on the original design. As a result, numerous meetings and discussions occurred during which a new design was developed that would alleviate the public opposition. The new design was developed and permitted without local opposition. The new design will include the expansion of the existing FPL O'Neil Substation. One circuit of the FPUC 138 KV line will be routed through this substation in order to allow for the transmission line interconnection with FPL. The remaining circuit of the FPUC 138 KV transmission line will remain as originally constructed and will provide for a direct interconnection with the JEA Nassau Substation. The new design will provide for improved system reliability on the transmission system and will afford FPUC the opportunity to reach other less expensive generation sources while avoiding additional transmission wheeling costs.

Q. **When will construction of the FPL transmission interconnection begin and what is the revised in service date?**

A. The construction of the FPL transmission line interconnection project is currently underway. FPL, JEA and FPUC are all actively involved in different aspects of the construction project. Completion of the 138 KV transmission line interconnection between FPL and JEA will be completed during the fourth quarter of 2017. Service using the FPL transmission line interconnection will be available on January 1, 2018.

Q. **Can you quantify or project the savings to be derived as a result of this new interconnect with FPL?**

A. Consistent with my testimony in Docket No. 20160001-EI, at this time, we cannot specifically define the savings attributed to the FPL transmission line interconnection. However, FPUC witness Mike Cassel will address the overall impact that projects have had on our overall rate.

Q. **What is the status of the existing purchase power agreement in place with Gulf and JEA?**

A. The existing agreement with Gulf is effective through December 31, 2019. It is anticipated that re-evaluation of that agreement will begin during the first half of 2018 in order to have an new agreement in place well in advance of the December 31, 2019 expiration date. The existing agreement with JEA will expire on December 31, 2017 and will be replaced with a new agreement from FPL with an effective date of January 1, 2018.

Q. **Can you provide background on the new purchased power agreement with FPL that will be effective January 1, 2018?**

A. Yes. The "Solicitation for Proposals to Provide Power Supply and Ancillary Services" (SPPS) for the Northeast Florida Division was issued to selected parties on June 20, 2016 with responses requested by August 1, 2016. Proposals were received from three parties and the evaluation and discussions began immediately thereafter. Based on the differences in the bids submitted, the evaluation became fairly complex and required additional time for soliciting additional information to allow for further evaluation. After the evaluation was completed, FPL was determined to be the most appropriate selection and additional negotiations were conducted in order to develop a comprehensive purchased power agreement. On April 10, 2017 the "Native Load Firm All Requirements Power and Energy Agreement" (Agreement) was executed by both parties with an effective date of January 1, 2018 and continuing in effect through December 31, 2024.

Q. Is this Agreement structured the same as the purchased power agreement you have in place at this time.

A. No. Although the Agreement is similar to the existing agreements in that it is an all-requirements purchased power agreement it does have some additional beneficial elements that provide for an overall cost reduction that will benefit the FPUC customers. Whereas existing agreements have capacity and energy components for all power requirements, this Agreement consist of both Intermediate Block Service (Block) and Load Following Service (Load Following) capacity and energy components which blend with other generation on Amelia Island to provide for a low cost solution. The Block was optimized to provide for very low cost capacity and energy with an extremely high capacity factor. Although the Load Following has costs above the Block, this will only be utilized when the Block and other on-island resources are not able to provide for all the energy and capacity requirements on Amelia Island. Also, this contract does provide other very beneficial elements such as the for the ability to construct additional on-island Combined Heat and Power generation, construct additional on-island Solar PV generation projects and to have access to Non-Firm Energy for use by selected industrial customers with high energy requirements.

Q. Has the Company availed itself of other opportunities to produce fuel cost savings?

A. Yes. The Northeast Florida Division provides service to two paper mills on Amelia Island that have significant on site generation capabilities and is directly connected to the Eight Flags Combined Heat and Power generation facility. Our relationships with these generators have created further opportunities for the purchase of on-island power. FPUC is continuing to look at these types of arrangements and all other avenues for reducing purchased power costs.

Q. When were the agreements for the on-island generators put into place?

A. The first very successful arrangement is the renewable energy contract with Rayonier Performance Fibers, LLC ("Rayonier"), which was entered into in early 2012 and approved by the Commission in Docket

No. 120058-EQ. Through a cooperative effort, FPUC and Rayonier were able to develop a purchased power agreement that allows Rayonier to produce renewable energy and sell that energy to FPUC at a cost below that of the current wholesale power provided while still being beneficial to Rayonier. Not only did this increase the amount of renewable energy in the area, it provides lower cost energy that is passed directly through to FPUC customers in the form of reduced power cost.

Secondly, the WestRock paper mill provides as-available energy under our Standard Offer Contract. Currently, evaluations are underway to look at the benefits associated with the formalization of a purchased power agreement with WestRock that could provide additional benefits to both entities.

Thirdly, a "Negotiated Contract Between Florida Public Utilities Company and Eight Flags Energy, LLC for the Purchase of Electric Energy from a Qualifying Facility" was effective on September 26, 2014. This contract provides was reasonably priced, base load, on-island generation that provides significant benefits to the FPUC customers on Amelia Island.

Q. How have these arrangements proven beneficial to the Company?

A. In addition to significant cost savings, these projects have been beneficial to the Company's electric customers by securing additional service reliability for the Northeast Florida Division. Also, due to the consolidated fuel factor, customers in both of the Company's electric divisions will benefit from the fuel and purchased power savings. Moreover, the Eight Flags project produces all these benefits, while doing so with a lower environmental profile than would be associated with locating traditional generation on the island or with FPUC's purchased power options.

Q. Are there other efforts underway to identify projects that will lead to lower cost energy for FPUC customers?

A. Yes. FPUC continues to work with consultants, as well as project developers, to identify new projects and opportunities that can lead to reduced fuel costs for our customers. We also continue to analyze the feasibility of energy production and supply opportunities that have been on our planning horizon for some time and noted in prior fuel clause proceedings, namely additional Combined Heat and Power (CHP) projects and potential Solar Photovoltaic ("PV") projects.

Q. Can you provide additional information on these CHP projects?

A. Yes. The success of the Eight Flags project has sparked interest in other CHP opportunities on Amelia Island. When coupled with industrial expansion in the area and the ability to do so within the context of the Agreement with FPL, the already quantifiable benefits of these existing projects has piqued the interest of others to contemplate partnering with a new CHP-based project. Given that FPUC would again be the recipient of any power generated by such project, FPUC has been involved in the analysis and feasibility study for potential new projects.

These projects are still in the planning stages, but the early indications are that the projects would not only be feasible, but would provide benefits to all parties involved.

Q. Can you provide additional information on the PV projects you referenced above?

A. Yes. FPUC has determined that the development of smaller PV systems within the FPUC electric service territory may be economically feasible and could provide benefits to the rate payers. Based on this analysis, FPUC is working to acquire access to the necessary property to construct small scale (one to five megawatts) PV installations. Not only will this increase the renewable energy available to FPUC, the cost is expected to complement the overall purchased power portfolio which will provide additional benefits to FPUC customers. Additionally, exploration into the inclusion of battery storage capacity in conjunction with the PV installation is being considered. These projects are still in the early stages of analysis and development. Nonetheless, even in these early analysis and planning stages, the potential benefits of the PV projects under consideration have been very encouraging.

Q. Does this include your testimony?

A. Yes.

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 2nd day of November, 2017.

Debbie R Krick

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