BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20180001-EI

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.
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VOLUME 1
PAGES 1 through 211

PROCEEDINGS: HEARING

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

DATE: Monday, November 5, 2018

TIME: Commenced: 5:45 P.M.
Concluded: 5:58 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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TALLAHASSEE, FLORIDA
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APPEARANCES:

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

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

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

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

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

JON C. MOYLE, JR., and KAREN PUTNAL, ESQUIRES, Moyle Law Firm, P.A., 118 North Gadsden Street,

APPEARANCES (CONTINUED):

Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

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

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

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

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

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID	ADMITTED
1	Comprehensive Exhibit List	8	8
2-87	As identified in the comprehensive exhibit list	8	
67-87	As identified in the comprehensive exhibit list		9
88	Stipulation language for Issues No. 15A and 15B	9	9
3-66	As identified in the comprehensive exhibit list		15

P R O C E E D I N G S

COMMISSIONER CLARK: All right. Let's proceed with the 01 docket. We will begin with preliminary matters, Ms. Brownless.

MS. BROWNLESS: Yes, sir. Opening statements, if any, are limited to three minutes per party.

The following issues are contested and will require a vote by the Commission: Issues 1A, 2A, 4A and 5A, which are the hedging issues. Issue 1B, the DEF Bartow replacement power, that also -- there also are DEF fallout issues. Issues 8, 10, 18, 20 and 22. Issues 2M and 2N, which are the FPL 2018 SoBRA issues. Issues 2P, 2Q, 2R and 2S, which are the FP&L 2019 SoBRA issues.

All the other issues are Type 2 stipulations that can be voted on today.

I want to bring to everyone's attention that Issue No. 33, as stated in your prehearing order, has an error and it's on page 62. And this was my fault, it was bad typing on my part -- or I am sorry on page 63. In the chart at the very top of the page, where is says GSLD3, GSLDT3, CS3, CST3, instead of being 0.98 as shown here, it should be 0.88. And obviously, that's a decrease from what is stated in the prehearing order.

Those are the preliminary --

COMMISSIONER CLARK: Ms. Brownless, could you repeat that one more time?

MS. BROWNLESS: Sure.

On page 62, at the top of page 63, and this is Issue No. 33 for FP&L. The second line on that table at the very top of the page shows GSLD3, GSLDT3, CS3 and CST3 factors listed at 0.98. It should be 0.88, and that was a typo on my part.

COMMISSIONER CLARK: Okay. Are we all clear?

MS. BROWNLESS: Yes, sir. Thank you.

COMMISSIONER CLARK: Okay. All right. Let's talk prefiled testimony. Ms. Brownless.

MS. BROWNLESS: For excused witnesses, the only witness that will be testifying today that has not been excused and stipulated to is DEF's witness Mr. Swartz, and the prefiled testimony of all the other witnesses has been stipulated to, and we will move that into the record shortly.

COMMISSIONER CLARK: Okay. All right. Let's move to staff exhibits.

MS. BROWNLESS: Thank you.

The parties -- the staff has compiled a stipulated comprehensive exhibit list which includes the prefiled exhibits attached to the witness' testimony, as well as staff's Exhibits 67 through 87. The list as been provided to the parties, the Commissioners and the court reporter.

At this time, the staff requests that the comprehensive exhibit list be marked for identification purposes as Exhibit No. 1, and the other exhibits be marked as identification in the as set forth in the comprehensive exhibit list.

COMMISSIONER CLARK: All right. Exhibit No. 1 is entered.

(Whereupon, Exhibit No. 1 was marked for identification and received into evidence.)

(Whereupon, Exhibit No. 2-87 were marked for identification.)

COMMISSIONER CLARK: And let's go to the rest of the exhibits.

MS. BROWNLESS: Thank you.

At this time, we would request that the stipulated staff exhibits, which are issues number 67 through 87, be entered into the record.

COMMISSIONER CLARK: Is that 87 or 88?

MS. BROWNLESS: 67 through 87. We are going to get to 88 in just a minute.

COMMISSIONER CLARK: Okay. Great. All right, make it so.

(Whereupon, Exhibit Nos. 67-87 were received into evidence.)

MS. BROWNLESS: Thank you.

Now, it was brought to our attention today that we inadvertently did not include the stipulation language for Issues No. 15A and 15B, and we have provided those stipulated language to everyone. These are Tampa Electric issues.

My understanding is that all the parties are agreeable to this language that has been provided. We would like to mark the handout that we gave as Exhibit No. 88, and that would be stipulated language for Issue 15A and 15B. And we would also ask that it be moved into the record at this time.

COMMISSIONER CLARK: Okay. Are there any objections to the exhibit?

All right. Seeing none, we will move it into the record.

MS. BROWNLESS: Thank you.

(Whereupon, Exhibit No. 88 was marked for identification and received into evidence.)

COMMISSIONER CLARK: Okay. I guess we are at stipulated issues.

MS. BROWNLESS: Yes, sir. The Type 2 stipulations are for the following issues: Issues

2B through 2L, 2O, 2T, 3A, 6, 7, 9, 11, 15A, 15B, 16, 17, 19, 21, 23A, 24A through 24E, 26 through 36 -- 27 through 36 for DEF, FIPUG, FPUC, TECO, Gulf and FP&L as appropriate.

Issues 8, 10, 18, 20 and 22 have been stipulated to for FPL, FIPUG, FPUC, TECO and Gulf, but not for Duke. These are listed on pages 33 through 64 of the prehearing order. And what we've just marked as Exhibit No. 88, and we would ask at this time for a bench decision on these issues.

COMMISSIONER CLARK: Okay. Any of the Commissioners have any questions on any of the proposed stipulated issues?

If you have none, I would entertain a motion if you so desire to approve the stipulations as presented.

COMMISSIONER POLMANN: Mr. Chairman, I would move approval of the Type 2 stipulations that were just enumerated by Ms. Brownless without going through the list again.

COMMISSIONER BROWN: If I may make a friendly amendment to that --

COMMISSIONER POLMANN: Please.

COMMISSIONER BROWN: -- and just note Issue No. 33 has a modification as presented orally --

COMMISSIONER CLARK: As modified.

COMMISSIONER BROWN: -- today.

COMMISSIONER FAY: Second.

COMMISSIONER CLARK: As modified.

I have a motion and a second.

Is there any discussion, questions or concerns?

All right. On the motion, all in favor, say aye.

(Chorus of ayes.)

COMMISSIONER CLARK: Opposed?

(No response.)

COMMISSIONER CLARK: The motion carries.

Okay. Next up is the contested hedging issues, Ms. Brownless.

MS. BROWNLESS: Yes, sir.

These are Issues 1A, 2A, 4A and 5A, and they are for Duke, FP&L, Gulf and TECO. They are listed on pages 8, 9, 17 and 18 of your prehearing order.

While the Florida Retail Federation has taken positions on Issues 1A, 2A, 4A and 5A contrary to the positions of the IOUs, my understanding is that FRF has agreed to waive cross-examination on these issues, and briefing on these issues, and does not object to a bench vote on these issues.

And I would like to ask Mr. Wright if that's a correct statement.

COMMISSIONER CLARK: Mr. Wright.

MR. WRIGHT: That is a correct representation of our potions. Thank you, Mr. Chairman.

COMMISSIONER CLARK: Thank you, sir.

All right. All other parties in agreement? Okay.

MS. BROWNLESS: So at this time, we would ask, if the Commission so desires, that a bench vote be taken on these issues.

COMMISSIONER CLARK: Okay, that's on 1A, 2A, 4A and 5A for DEF, FPL, Gulf and TECO?

MS. BROWNLESS: Yes, sir.

COMMISSIONER CLARK: All right. We are ripe for a motion.

COMMISSIONER BROWN: Mr. Chairman, I would move approval of the stipulations on Issues 1A, 2A, 4A and 5A in this docket.

COMMISSIONER POLMANN: Second.

COMMISSIONER CLARK: I have a motion and a second to approve the stipulations.

Any discussion?

On the motion, all in favor, say aye.

(Chorus of ayes.)

COMMISSIONER CLARK: Opposed?

(No response.)

COMMISSIONER CLARK: The stipulations are approved.

Okay. Contested issues.

MS. BROWNLESS: Yes, sir.

COMMISSIONER CLARK: Go ahead.

MS. BROWNLESS: With regard to the contested issues, the contested issues are listed on pages 9, 12 through 16 and 19 through 22. And we would note that because I believe neither TECO nor Gulf has any issues remaining, if they would like to be excused -- oh, I am sorry, and FPUC.

COMMISSIONER CLARK: I see hands waiving. It's either good-bye or I need attention.

Ms. Keating, would you like to be excused?

MS. KEATING: I would very much like to be excused. Thank you, Commissioner.

MR. BEASLEY: As would Tampa Electric, sir.

MR. BADDERS: As would Gulf. I just would note that the company exhibits have not yet been entered, so we would like to do that prior to being excused.

COMMISSIONER CLARK: Okay. You guys are all excused. Thank you very much.

Okay. It's time for opening statements.

We would like to limit the opening statements, it's got five minutes, we are going to try to work off of three, I think, if we can get you guys to cooperate.

Ms. Brownless, am I forgetting something?

MS. BROWNLESS: No, sir. I think we are good.

Do you want to do your exhibits? We were going to do those at the very end because there is only one witness, but we can do them now if you wish.

MR. BEASLEY: That would be nice.

COMMISSIONER CLARK: They want their exhibit -- was this your exhibits?

MR. BADDERS: Yes, the exhibits.

COMMISSIONER CLARK: Okay. What numbers with were they, Ms. Brownless?

MS. BROWNLESS: Well, why don't we go ahead and do all the stipulated utility exhibits. Let's just do everybody.

COMMISSIONER CLARK: Okay.

MS. BROWNLESS: And that would be the stipulated utility exhibits Nos. 3 through 66 being moved into the record.

COMMISSIONER CLARK: Without objection, so ordered.

(Whereupon, Exhibit Nos. 3-66 were received into evidence.)

MR. BEASLEY: Thank you.

MS. BROWNLESS: You're welcome.

COMMISSIONER CLARK: They are all covered.

Thank you all very much.

MR. BEASLEY: Appreciate it.

MR. BADDERS: Thank you.

MS. BROWNLESS: And we should probably, if we're going to do that, also move the stipulated prefiled testimony of the witnesses who are excused.

COMMISSIONER CLARK: Okay.

MS. BROWNLESS: Do you want to do that as well?

COMMISSIONER CLARK: So ordered.

MS. BROWNLESS: All right. And I will read them.

The stipulated prefiled testimony of Menendez, Maclay, Jones, Deaton, Yupp, Kiley, Rote, Castaneda as corrected on October 31st; Brannen, Enjamio, Cohen, Young, Cassel, Cutshaw, Boyett, Nicholson, Rusk, Buckley, Smith, Caldwell, Ojada -- that's not right. I always mess her name up -- and Dobiac, Brown and Terkawi be moved into the record as though read.

COMMISSIONER CLARK: Okay. Make it so.

(Prefiled testimony inserted.)

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20180001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2017 - December 2017

DIRECT TESTIMONY OF
Christopher A. Menendez

March 2, 2018

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 First Avenue North, St. Petersburg, 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 Adjustment 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 2017 through December 2017, 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 2017, year-to-date; and Exhibit No. __(CAM-4T), a schedule outlining the 2017 capital structure and cost rates applied to capital projects. Exhibit No. __(CAM-4T) is included for informational purposes only, as DEF's 2017 Actual True-Up Filing does not include a capital return component. Schedules A1 through A9, and A12 for the year ended December 31, 2017, were filed with the Commission on January 19, 2018.

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-2018-0028-FOF-EI, the estimated 2017 fuel adjustment true-up amount was an under-recovery of $195.5 million. The actual under-recovery for 2017 was $211.6 million resulting in a final fuel adjustment true-up under-recovery amount of $16.1 million. Exhibit No. __(CAM-1T).

The estimated 2017 capacity cost recovery true-up amount was an under-recovery of $5.1 million. The actual amount for 2017 was an under-recovery of $4.8 million resulting in a final capacity true-up over-recovery amount of $0.3 million. Exhibit No. __(CAM-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2017 for fuel cost recovery?

A. The actual ending balance as of December 31, 2017 for true-up purposes is an under-recovery of $211,599,981.

Q. How does this amount compare to DEF's estimated 2017 ending balance included in the Company's Actual/Estimated Filing?

A. The actual true-up amount attributable to the January 2017 - December

2017 period is an under-recovery of $211,599,981 which is $16,096,208 higher than the re-projected year end under-recovery balance of $195,503,774.

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 net under-recovery of $16,096,208 shown on your Exhibit No. __(CAM-1T)?

A. The $16.1 million primarily consists of approximately $11.1 million in replacement power costs associated with the Bartow Combined Cycle Plant which is discussed below, and an approximate $3.5 million adjustment coal inventory from the semi-annual aerial surveys.

Q. Please explain the components shown on Exhibit No. __(CAM-1T), sheet 6 of 6, which helps to explain the $4.2 million favorable system variance from the projected cost of fuel and net purchased power transactions.

A. Exhibit No. __(CAM-1T), sheet 6 of 6 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 $4.2 million favorable system variance is mainly attributable to a shift from coal to natural gas generation driven primarily by favorable natural gas pricing.

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 $3.5 million to coal inventory attributable to the semi-annual aerial surveys conducted on May 26, 2017 and October 31, 2017 in accordance with Docket No. 19970001-EI, Order No. PSC-1997-0359-FOF-EI. This adjustment represents 1.13% of the total coal consumed at the Crystal River facility in 2017.

Q. On February 9, 2017, an outage occurred at the Bartow 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 $11.0 million (approximately $11.1 million system). Consistent with the Stipulated Resolution to Issue 1B in Docket No. 20170001-EI, DEF excluded these costs for ratemaking purposes in the 2017 Actual/Estimated Filing. DEF has included these costs in its Final 2017 True-Up balance.

Q. Did DEF exceed the economy sales threshold in 2017?

A. No. DEF did not exceed the gain on economy sales threshold of $3.0 million in 2017. As reported on Schedule A1-2, Line 11a, the gain for the year-to-date period through December 2017 was $0.9 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 October 2017 hearings been updated to incorporate actual data for all of year 2017?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2015 through 2017, as follows:

Year	Actual Gain
2015	$3,720,655
2016	$ 843,842
2017	$ 887,370

Three-Year Average $1,817,289

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2017 for capacity cost recovery?

A. The actual ending balance as of December 31, 2017 for true-up purposes is an under-recovery of $4,775,185.

Q. How does this amount compare to the estimated 2017 ending balance included in the Company's Actual/estimated Filing?

A. When the estimated 2017 under-recovery of $5,121,339 is compared to the $4,775,185 actual under-recovery, the final capacity true-up for the twelve month period ended December 2017 is an over-recovery of $346,154.

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-1996-1172-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 $0.3 million?

A. Exhibit No. __(CAM-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $0.3 million over-recovery is primarily due to lower than estimated costs.

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

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20180001-EI

Fuel and Capacity Cost Recovery
Actual/Estimated True-Up Amounts
January through December 2018

DIRECT TESTIMONY OF
Christopher A. Menendez

July 27, 2018

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. 20180001-EI?

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

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

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission 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 2018.

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 2018 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-2018-0079-PCO-EI. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2018 actual/estimated capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2018 and estimated data from July through December 2018.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2018 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is an under-recovery of $148,450,915. The calculation begins with the actual under-recovered balance of $215,108,517 taken from Schedule A2, page 2 of 2, line 13, for the month of June 2018. This balance plus the estimated July through December 2018 monthly true-up calculations comprise the estimated $148,450,915 under-recovered balance at year-end. The projected December 2018 true-up balance includes interest which is estimated from July through December 2018 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.160% per month.

Q. How does the current forecast of fuel costs on Schedule E3 for July through December 2018 compare with the same period forecast used in the Company's 2018 projection filing approved in Order No. PSC-2018-0028-FOF-EI?

A. Natural gas, coal and light oil costs increased $0.10/mmbtu (2%), $0.39/mmbtu (13%) and $9.50/mmbtu (50%), respectively.

Q. Have any adjustments been made to estimated fuel costs for the period July through December 2018?

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ dated June 8, 2018, DEF included an adjustment of $6,232,811 (grossed up to $6,266,531 from retail to system) for the amortization of Florida Power Development, LLC qualifying facility regulatory asset from August 2018 through December 2018. This adjustment is included on Schedule E1-B (sheet 2), line A5, columns Aug Estimated through Dec Estimated.

Q. Does DEF expect to exceed the three-year rolling average gain on non-separated power sales in 2018?

A. Yes. DEF estimates the total gain on non-separated sales during 2018 will be $2,179,293, which exceeds the three-year rolling average of $1,817,289. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gains in excess of the three-year rolling average. For 2018, this is estimated to be $72,401.

CAPACITY COST RECOVERY

Q. What is DEF's 2018 estimated capacity true-up balance and how was it developed?

A. DEF's estimated capacity true-up balance is an over-recovery of $16,610,473. The estimated true-up calculation begins with the actual under-recovered balance of $10,627,989 for the month of June 2018. This balance plus the estimated July through December 2018 monthly true-up calculations comprise the estimated $16,610,473 over-recovered balance at year-end. The projected December 2018 true-up balance includes interest which is estimated from July through December 2018 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.160% per month.

Q. What are the primary drivers of the estimated year-end 2018 capacity under-recovery?

A. The $16.6 million over-recovery is primarily attributable to approximately $9.2 million lower capacity costs, approximately $7.1 higher than projected capacity revenues and approximately $0.3 million prior period true up over-recovery balance.

Q. Has DEF included the nuclear cost recovery amounts approved in Order No. PSC-2017-0445-FOF-EI?

A. Yes. DEF has included $49,612,736 of 2018 recoverable expenses associated with the CR-3 Uprate project.

Q. Has DEF included the Department of Energy award in its ISFSI costs?

A. Yes. Consistent with the 2017 Second Revised and Restated Settlement Agreement approved by the Commission in Order No. PSC-2017-0451-AS-EU, DEF reduced the Independent Spent Fuel Storage Installation (ISFSI) regulatory asset by approximately $18.3 million in February 2018.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20180001-EI

Fuel and Capacity Cost Recovery Factors
January through December 2019

DIRECT TESTIMONY OF
Christopher A. Menendez

August 24, 2018

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. 20180001-EI?

A. Yes, I provided direct testimony on March 2, 2018 and July 27, 2018.

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 2019.

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 also included 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 by Order No. PSC-2018-0079-PCO-EI. Part 3 contains capacity cost recovery ("CCR") schedules.

FUEL COST RECOVERY CLAUSE

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

A. Schedule E1 shows the calculation of the Company's jurisdictional fuel cost factor of 3.969 ¢/kWh. This factor consists of a fuel cost for the projection period of 3.5943 ¢/kWh (adjusted for jurisdictional losses), a GPIF penalty of (0.0059) ¢/kWh, and an estimated prior period under-recovery true-up of 0.3778 ¢/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 CCR factors.

Schedule E1-D, lines 11-12 show the Company's proposed tiered rates of 3.698 ¢/kWh for the first 1,000 kWh and 4.698 ¢/kWh above 1,000 kWh. These rates are developed in the "Calculation of Inverted Residential Fuel Rates" schedule in Part 2 of my exhibit.

Schedule E1-E develops the Time of Use ("TOU") multipliers of 1.247 On-peak and 0.891 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 2018 net true-up that DEF has included in the fuel cost recovery factor for 2019?

A. DEF has included a projected under-recovery of $148,450,915. This amount includes a projected actual/estimated under-recovery for 2018 of $34,602,826, a final 2017 true-up net under-recovery of $16,096,207 as shown in my Direct Testimony filed on March 2, 2018, and the second half of the 2017 true-up under-recovery deferral of $97,751,882, as included in DEF's Second Revised and Restated Stipulation and Settlement Agreement ("2017 Settlement") approved in Order No. PSC-2017-0421-AS-EU.

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 2019 of 3.974 ¢/kWh is a decrease of 0.158 ¢/kWh or 4% from the 2018 levelized residential fuel factor of 4.132 ¢/kWh.

Q. Please explain the decrease in the 2019 fuel factor compared with the 2018 fuel factor.

A. The primary drivers of the decrease in the 2019 fuel factor are a decrease in jurisdictional fuel and purchased power expense of approximately $84 million and a decrease in the GPIF amount of approximately $5 million partially offset by an increase in the prior period true-up of approximately $51 million.

Q. Have you made any adjustments to your estimated fuel costs for the period January through December 2019?

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ dated May 8, 2018, DEF included an adjustment of $14,228,988 (grossed up to $14,305,402 from retail to system) for the amortization of Florida Power Development, LLC qualifying facility regulatory asset from January 2019 through December 2019.

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

A. Yes. DEF is proposing to continue use of the inverted rate design for residential fuel factors to encourage energy efficiency and conservation.

Specifically, the Company proposes to continue a two-tiered fuel charge whereby the charge for a customer's monthly usage in excess of 1,000 kWh (second tier) is priced one cent per kWh higher than the charge for the customer's usage up to 1,000 kWh (first tier). The 1,000 kWh price change breakpoint is reasonable in that approximately 72% of all residential energy is consumed in the first tier and 28% of all energy is consumed in the second tier. The Company believes the one cent higher per unit price, targeted at the second tier of the residential class' energy consumption, will promote energy efficiency and conservation. This inverted rate design was incorporated in the Company’s base rates approved in Order No. PSC-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 3.974 ¢/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 2019 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2019 is estimated to be $1,748,022 which is above the benchmark of $1,303,502. 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 above the benchmark, $88,904 of the gains will be retained for shareholders. The benchmark was calculated based on the average of actual gains for 2016 and 2017 of $843,842 and $887,370, respectively, and estimated gains for 2018 of $2,179,293 in accordance with Order No. PSC-2000-1744-PAA-EI.

Q. Please explain the entry on Schedule E1, line 11, "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 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 2017 GPIF penalty discussed in the March 2, 2018 direct testimony of Matt J. Jones included in 2018 rates?

A. Yes. The GPIF penalty of $2,301,526 is included on Schedule E1, Line 26 of Exhibit CAM-3, Part 2.

Q. Does DEF's Weighted Average Cost of Capital ("WACC") comply with paragraph 19 of the 2017 Settlement?

A. Yes. The WACC complies with paragraph 19 of the 2017 Settlement.

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:

Schedule E12-A – Calculation of Projected Capacity Costs – Year 2019

Page 1 of Schedule E12-A includes estimated 2019 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 the 2017 Settlement.

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 7, 2018, in Docket 20180009-EI. The recovery of estimated Dry Casket Storage costs, also referred to as Independent Spent Fuel Storage Installation ("ISFSI") costs, are included on line 38 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 2019 Calculation of Projected Capacity Costs on Schedule E-12A, line 39.

Schedule E12-B – Calculation of Estimated/Actual True-Up - Year 2018

Schedule E12-B, which is also included in Exhibit __(CAM-2) to my direct testimony filed on July 27, 2018, as part of the 2018 actual/estimated true-up filing, calculates the estimated true-up capacity over-recovered balance for calendar year 2018 of $16,610,473. This balance is carried forward to Schedule E12-A, line 29 to be collected from customers from January through December 2019.

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, page 1 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, respectively. 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 Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI, 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 – 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 2017 through March 2018 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, 2018.

Q. What is the 2019 projected average retail CCR factor?

A. The 2019 average retail CCR factor is 1.097 ¢/kWh, made up of capacity of 0.967 ¢/kWh, ISFSI costs of 0.018 ¢/kWh and CR3 Uprate costs of .0112 ¢/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 1.097 is 0.115 ¢/kWh, or 10%, lower than the 2018 factor of 1.212 ¢/kWh. This decrease is primarily due to the conclusion of the recovery of RRSSA 2nd Amendment costs at year end 2018, as approved in Order No. PSC-2016-0138-FOF-EI, and the difference in the in the prior period true-up balance.

Q. Does this conclude your testimony?

A. Yes

DUKE ENERGY FLORIDA

DOCKET NO. 20180001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December 2017

DIRECT TESTIMONY OF JAMES MCCLAY

April 3, 2018

Q. Please state your name and business address.

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

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

A. I employed by Duke Energy Carolinas (DEC) an affiliate company of Duke Energy Florida, Inc. ("DEF", "Petitioner" or "Company") as the Manager of Gas Trading. I manage the natural gas group procurement, scheduling and hedging activities in the Fuel Procurement Section of the Fuels and Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for the natural gas procurement and scheduling needed to support the gas generation needs for Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida.

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 Finance from St. Bonaventure University. I joined Progress Energy in 1998 as the Manager of Power Trading and held that position through early 2003 and then became the Director of Power Trading and Portfolio Management for Progress Energy Ventures through February 2007. From March 2007 through late 2008, I was the Director of Power Trading for Arclight Energy Marketing. From March 2009 through present I've been the Manager of Gas and Oil Trading with Progress Energy and Duke Energy. Prior to my tenure with Duke Energy, I spent approximately 13 years in Capital Markets as a U.S. Government fixed income securities trader with various banks, and primary broker/ dealers.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the August through December 2017 hedging true-up data and summarize the results of DEF's hedging activity for calendar year 2017 as required by Commission Order No. PSC-02-1484-FOF-EI and further clarified by Commission Orders No. PSC-08-0667-PPA-EI issued in October 2008, and 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 2017.

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

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

Q. What hedging activities did DEF undertake for 2017 and what were the results?

A. As discussed below, DEF did not execute any hedges during 2017. Prior hedging activities resulted in a net hedge cost for 2017 of approximately $35.0 million.

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

A. As part of the Joint Stipulation and Agreement for Interim Resolution of Hedging Issues filed on October 24, 2016 in Docket No. 20160001-EI, DEF withdrew its 2017 Risk Management Plan and ceased hedging activities. Subsequently, DEF agreed to a hedging moratorium during the term of the 2017 Second Revised and Restated Stipulation and Settlement Agreement, approved by the Commission in Docket No. 20170183-EI. Notwithstanding the suspension of prospective hedging activities, DEF had hedging transactions entered into under previously approved risk management plans that settled in 2017.

As outlined in those earlier Commission-approved plans, 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 2018

FPSC DOCKET NO. 20180001-EI

DIRECT TESTIMONY OF
James McClay

August 10, 2018

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

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

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

A. I employed by Duke Energy Carolinas ("DEC") an affiliate company of Duke Energy Florida, LLC ("DEF", "Petitioner" or "Company") as the Manager of Gas Trading. I manage the natural gas group procurement, scheduling and hedging activities in the Fuel Procurement Section of the Fuels and Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for natural gas procurement, scheduling and financial hedging for the natural gas activities needed to support the generation needs for Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Progress, DEC and DEF.

Q. Please describe your education background and professional experience.

A. I received a Bachelor Degree in Business Administration majoring in Finance from St. Bonaventure University. I joined Progress Energy in 1998 as the Manager of Power Trading and held that position through early 2003 and then became the Director of Power Trading and Portfolio Management for Progress Energy Ventures through February 2007. From March 2007 through late 2008, I was the Director of Power Trading for Arclight Energy Marketing. From March 2009 through present I have been the Manager of Gas Trading with Progress Energy and Duke Energy. Prior to my tenure with Duke Energy, I spent approximately 13 years in Capital Markets as a U.S. Government fixed income securities trader with various banks, and primary broker / dealers.

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 2018 through July 2018.

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 2018 through July 2018.

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.

Q. Describe the hedging activities that the Company has executed for 2019.

A. As approved by the Commission, DEF is currently under a moratorium on hedging and has not executed any financial hedges for any periods since October 21, 2016. As of July 31, 2018, DEF had hedges in place for approximately 1.3 percent of its current forecasted natural gas burns for 2019. 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 2018?

A. The Company's natural gas hedging activities for the period of January 2018 through July 2018 have resulted in hedges being above the closing natural gas settlement prices by approximately $4.7 million**.** 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. 20180001-EI

GPIF Schedules for
January through December 2017

DIRECT TESTIMONY OF MATTHEW J. JONES

March 15, 2018

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.

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 Corporation's regulated utility subsidiaries, including Duke Energy Florida, LLC ("DEF" or "Company"), as well as DEC, 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. 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 2017. 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 penalty of $2,301,526. 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.

Pursuant to Sections 4.3.1 and 4.3.2 of the GPIF Implementation Manual, adjustments were made to remove the impacts of Hurricane Irma in September 2017. This was accomplished by removing generation and fuel used during events specifically identified as hurricane-related and by classifying forced outage hours and partial forced outage hours for those same events as service hours. Hurricane-related events were recorded for Crystal River 4 and 5, and Hines 2 and 3.

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 2017

FPSC DOCKET NO. 20180001-EI

GPIF TARGETS AND RANGES FOR JANUARY THROUGH DECEMBER 2019

DIRECT TESTIMONY OF MATTHEW J. JONES

August 24, 2018

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 2017 and also present the development of the Company's Generating Performance Incentive Factor ("GPIF") targets and ranges for the period January through December 2019. 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, 2018 testimony for the period January through December 2017?

A. DEF's originally calculated GPIF incentive amount for this period was a penalty of $2,301,526. Please refer to my testimony filed March 15, 2018 for the details of how this incentive amount was calculated.

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

A. No.

Q. Do you have an exhibit to your testimony?

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

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

A. For the 2019 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 Citrus CC units 1 and 2 as explained below.

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 rates can then be converted into an overall equivalent unplanned outage factor ("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 2019?

A. The estimated maximum incentive for the Company is $17,823,338. 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. 20180001-EI

MARCH 2, 2018

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 2017 through December 2017.

The 2017 net true-up for the FCR Clause is an under-recovery, including interest, of $23,632,267. FPL is requesting Commission approval to include this FCR Clause true-up under-recovery of $23,632,267 in the calculation of the FCR factor for the period January 2019 through December 2019.

The 2017 net true-up for the CCR Clause is an under-recovery, including interest, of $2,212,807. FPL is requesting Commission approval to include this CCR Clause true-up under-recovery of $2,212,807 in the calculation of the CCR factors for the period January 2019 through December 2019.

Finally, FPL is requesting Commission approval to include $2,317,099 in the calculation of the FCR factors for the period January 2019 through December 2019, which represents FPL's share of the 2017 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 any exhibits in this proceeding?

A. Yes, I have. Exhibit RBD-1 contains the FCR related schedules and Exhibit RBD-2 contains the CCR related schedules. In addition, FCR Schedules A1 through A12 for the January 2017 through December 2017 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 2017 FCR net true-up amount.

A. Exhibit RBD-1, page 1, titled "Summary of Net True-Up," shows the calculation of the net true-up for the period January 2017 through December 2017, an under-recovery of $23,632,267.

The summary of the net true-up amount shows the actual end-of-period true-up over-recovery for the period January 2017 through December 2017 of

$21,940,629 on line 1. The actual/estimated true-up over-recovery for the same period of $45,572,897 is shown on line 2. Line 1 less line 2 results in the net final true-up under-recovery for the period January 2017 through December 2017 of $23,632,267 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 2017 FCR actual true-up by month?

A. Yes. Exhibit RBD-1, page 2, titled "Calculation of Final True-up Amount," shows the calculation of the FCR actual true-up by month for January 2017 through December 2017.

Q. Have you provided schedules showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2017?

A. Yes. Exhibit RBD-1, page 3, (sum of lines 44 and 45) compares the actual end-of-period true-up over-recovery of $21,940,629 (column 3) to the actual/estimated end-of-period true-up over-recovery of $45,572,897 (column 4) resulting in a net under-recovery of $23,632,267 (column 5). Exhibit RBD-1, page 3 lines 43 and 34, shows that the variance consists of an increase in jurisdictional costs of $42.4 million partially offset by an increase in revenues of $18.9 million.

Q. Please summarize the variance schedule on page 3 of Exhibit RBD-1.

A. FPL previously projected jurisdictional total fuel costs and net power transactions to be $2.939 billion for 2017 (Exhibit RBD-1, page 3, line 43, column 4). The actual jurisdictional total fuel costs and net power transactions for that period is $2.981 billion (Exhibit RBD-1, page 3, line 43, column 3). Jurisdictional total fuel costs and net power transactions are $42.4 million, or 1.4% higher than previously projected (Exhibit RBD-1, page 3, line 43, column 5) and jurisdictional fuel revenues, net of revenue taxes for 2017 are $18.9 million, or 0.6% higher than previously projected (Exhibit RBD-1, page 3, line 34, column 5).

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

A. Below are the primary reasons for the $42.4 million variance.

<u>Fuel Cost of System Net Generation: $69.8 million increase (Exhibit RBD-1, page 3, line 2, column 5)</u>

The table below provides the detail of this variance.

Fuel Variance	**2017 FINAL TRUE-UP**	**2017 ACTUAL/ ESTIMATED**	**DIFFERENCE**
<u>Heavy Oil</u>			
Total Dollar	$24,618,491	$13,934,673	$10,683,819
Units (MMbtu)	2,060,902	1,185,043	875,859
$ per Units	11.9455	11.7588	0.1867
Variance Due to Consumption			$10,299,035
Variance Due to Cost			$384,783
Total Variance			$10,683,819

Fuel Variance	2017 FINAL TRUE-UP	2017 ACTUAL/ ESTIMATED	DIFFERENCE
Light Oil			
Total Dollar	$38,351,438	$34,663,972	$3,687,467
Units (MMbtu)	2,080,525	1,880,620	199,905
$ per Units	18.4335	18.4322	0.0013
Variance Due to Consumption			$3,684,693
Variance Due to Cost			$2,774
Total Variance			$3,687,467
Coal			
Total Dollar	$124,990,904	$120,910,198	$4,080,706
Units (MMbtu)	45,741,719	44,990,624	751,095
$ per Units	2.7325	2.6875	0.0451
Variance Due to Consumption			$2,018,533
Variance Due to Cost			$2,062,173
Total Variance			$4,080,706
Gas			
Total Dollar	$2,713,130,934	$2,657,374,216	$55,756,719
Units (MMbtu)	633,859,434	611,518,799	22,340,635
$ per Units	4.2803	4.3455	(0.0652)
Variance Due to Consumption			$97,081,934
Variance Due to Cost			($41,325,215)
Total Variance			$55,756,719
Nuclear			
Total Dollar	$189,997,758	$194,420,124	($4,422,366)
Units (MMbtu)	307,203,081	307,982,598	(779,517)
$ per Units	0.6185	0.6313	(0.0128)
Variance Due to Consumption			($492,086)
Variance Due to Cost			($3,930,280)
Total Variance			($4,422,366)
Total			
Variance Due to Consumption			$112,592,110
Variance Due to Cost			($42,805,766)
Total Variance			$69,786,344

<u>Fuel Cost of Power Sold: $3.5 million decrease (Exhibit RBD-1, page 3, line 6, column 5)</u>

The variance for the fuel cost of power sold is primarily attributable to lower than projected fuel costs attributable to economy sales. The average unit fuel cost on economy power sales was $2.29/MWh lower than projected, resulting in a cost decrease of $4.5 million. This variance was partially offset by higher than projected economy sales. FPL sold 1,963,107 MWh or 39,777 MWh more of economy power, resulting in an increase of $1.0 million. The combination of lower fuel costs attributable to economy power sales and higher economy power sales resulted in a net decrease of $3.5 million.

<u>Energy Cost of Economy Purchases: $15.9 million decrease (Exhibit RBD-1, page 3, line 10, column 5)</u>

The variance for the energy cost of economy purchases is primarily attributable to lower than projected economy purchases. FPL purchased 621,439 MWh, or 636,820 MWh less of economy power resulting in a volume decrease of $20.7 million. This volume decrease was partially offset by higher than projected costs for economy power. The average cost of economy purchases was $7.85/MWh higher than projected, resulting in a cost increase of $4.9 million. The combination of lower economy purchases coupled with higher costs for economy purchases resulted in a net decrease of $15.9 million.

<u>Energy Payments to Qualifying Facilities: $4.1 million decrease (Exhibit RBD-1, page 3, line 9, column 5)</u>

The variance for energy payments to qualifying facilities is primarily attributable to lower than projected purchases and costs from As-Available Co-Generation facilities. In total, FPL purchased 208,463 MWh, or 177,990 MWh less than projected from As-Available Co-Generation facilities at an average unit fuel cost that was $1.60/MWh lower than projected. The combination of lower As-Available purchases and lower fuel costs resulted in a decrease of $3.9 million. The remaining decrease of $0.1 million was attributable to lower than projected fuel costs from FPL's Firm Co-Generation facility, partially offset by higher than projected purchases of Firm Co-Generation power.

<u>Gains from Off-System Sales: $1.9 million increase (Exhibit RBD-1, page 3, line 7, column 5)</u>

The variance for gains from off-system sales is attributable to a higher than projected volume of economy sales coupled with higher than projected margins on those sales. FPL sold 1,963,107 MWh, or 39,777 MWh more of economy power than previously projected, resulting in an increase of $0.3 million. In addition, the margin on economy sales averaged $0.82/MWh more than projected, which resulted in an increase of $1.6 million. The larger volume and higher margin associated with the economy sales resulted in a total increase for gains from off-system sales of $1.9 million.

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

A. As shown on Exhibit RBD-1, page 3, line 34, actual 2017 jurisdictional FCR revenues, net of revenue taxes, were approximately $18.9 million higher than the actual/estimated projection. This was primarily due to jurisdictional sales that were 366,044 MWh higher than the actual/estimated projection.

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $2,317,099 as its 60% share of 2017 Incentive Mechanism gains over the $40 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 2017 Incentive Mechanism gains through the 2019 FCR factors, consistent with how gains have been recovered in prior years. FPL will include the approved jurisdictionalized Incentive Mechanism gains amount in the calculation of the 2019 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 2019 through December 2019 as a reduction to jurisdictional fuel revenues applicable to each period.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2017 CCR net true-up amount.

A. Exhibit RBD-2, page 1, titled "Final True-Up Summary" shows the calculation of the CCR net true-up for the period January 2017 through December 2017, an under-recovery of $2,212,807, which FPL is requesting to be included in the calculation of the CCR factors for the January 2019 through December 2019 period.

The actual end-of-period under-recovery for the period January 2017 through December 2017 of $8,862,166 shown on line 1 less the actual/estimated end-of-period under-recovery for the same period of $6,649,359 shown on line 2 that was approved by the Commission in Order No. PSC-2018-0028-FOF-EI, results in the net true-up under-recovery for the period January 2017 through December 2017 of $2,212,807 shown on line 3.

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

A. Yes. Exhibit RBD-2, page 2, titled "Calculation of Final True-up" shows the calculation of the CCR end-of-period true-up for the period January 2017 through December 2017 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 2017?

A. Yes. Exhibit RBD-2, 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 2017 through December 2017.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-2, page 3, line 17, column 5, the variance related to jurisdictional capacity costs is a decrease of $5.3 million, or 1.7%, from the actual/estimated projection. The primary reason for this variance is a $5.6 million or 1.7% decrease in total system capacity costs (page 3, line 14, column 5).

Below are the primary reasons for the $5.6 million decrease in total system capacity costs.

<u>Incremental Plant Security Costs - O&M: $3.6 million decrease (Exhibit RBD-2, page 3, line 8, column 5)</u>

The variance for incremental plant security costs - O&M is primarily attributable to the implementation of cost savings initiatives at the St. Lucie and Turkey Point plants resulting in lower security force costs. Additionally, NRC Homeland Security Fees and cyber security costs were lower than estimated.

<u>Payments to Non-Cogenerators: $2.1 million decrease (Exhibit RBD-2, page 3, line 1, column 5)</u>

The variance for payments to non-cogenerators (SJRPP and SWA) is primarily attributable to lower than projected costs associated with O&M and inventory of $2.8 million and property taxes of $0.14 million. Additionally, slightly lower than projected costs associated with the SWA agreement resulted in a decrease of approximately $0.14 million. This was partially offset by an increase in costs of approximately $1.0 million related to SJRPP for Cumulative Capital Recovery Amount payments.

<u>Incremental Nuclear NRC Compliance Costs (Fukushima): O&M - $0.9 million increase (Exhibit RBD-2, page 3, line 10, column 5)</u>

The variance for incremental NRC compliance O&M costs is primarily attributable to the NRC flooding analysis for flood doors that was previously projected as capital but later determined to be O&M and booked as such.

Q. Please describe the variance in CCR revenues.

A. As shown on page 3, line 22, column 5, actual CCR revenues (net of revenue taxes), were $7,519,744 lower than projected in the actual/estimated true-up filing. This was primarily due to the adjustment for recovery of base non-fuel revenue requirements associated with the Indiantown transaction. As discussed in my 2017 actual/estimated true-up testimony in Docket 20170001-EI, this adjustment was not included in the calculation of the 2017 CCR factor because the transaction had not yet been approved at the time of FPL's 2017 projection filing. The adjustment was partially offset by higher than projected jurisdictional sales, which were 366,044 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 Exhibit RBD-2 as pages 4 and 5. Page 4 shows the actual capacity payments for FPL's Purchase Power Agreements for the period January 2017 through December 2017. Page 5 provides the Short Term Capacity Payments for the period January 2017 through December 2017.

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 2017 through December 2017 are included on pages 11 and 12 of Exhibit RBD-2.

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. 20180001-EI

JULY 27, 2018

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 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 2018 through December 2018.

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 schedules and Exhibit RBD-4 contains the CCR schedules.

The FCR Schedules contained in Exhibit RBD-3 include Schedules E3 through E9 that provide revised estimates for the period July 2018 through December 2018. FCR Schedules A1 through A9 provide actual data for the period January 2018 through June 2018. 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 2018 through December 2018.

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 2018 through December 2018.

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 true-up calculations compare actual/estimated data consisting of actuals for January 2018 through June 2018 and revised estimates for July 2018 through December 2018 to the data reflected in FPL's mid-course correction for the period January 2018 through December 2018 filed on November 17, 2017. The CCR true-up calculations compare actual/estimated data consisting of actuals for January 2018 through June 2018 and revised estimates for July 2018 through December 2018 compared to the data reflected in FPL's mid-course correction for the period January 2018 through December 2018 filed on April 16, 2018.

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 2018, which reflects the interest rate from the last business day in June 2018.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2018 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 2018 through December 2018.

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 2018 end-of-period net true-up amount to be carried forward to the 2019 FCR factors is an under-recovery of $111,740,516 (page 1, line 46, column 15). This $111,740,516 under-recovery includes the 2017 final true-up under-recovery of $23,632,267 (Exhibit RBD-3, page 1, line 44, column 15), filed with the Commission on March 2, 2018, and the actual/estimated true-up under-recovery, including interest, of $88,108,249 (Exhibit RBD-3, page 1, lines 41 plus 42, column 15) for the period January 2018 through December 2018.

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 2018?

A. Yes. Exhibit RBD-3, page 2 provides a variance calculation that compares the 2018 actual/estimated period data by component to the same components from the 2018 mid-course correction filed on November 17, 2017.

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

A. FPL's mid-course correction filing projected jurisdictional total fuel costs and net power transactions to be $2.848 billion for 2018 (Exhibit RBD-3, page 2, line 43, column 4). The actual/estimated jurisdictional total fuel costs and net power transactions are now projected to be $2.887 billion for that period (Exhibit RBD-3, page 2, line 43, column 3). The estimated variance is due to higher than projected costs and lower than projected revenues. Jurisdictional total fuel costs and net power transactions are estimated to be $38.8 million, or 1.4% higher than the mid-course correction projection (Exhibit RBD-3, page 2, line 43, column 5), and jurisdictional fuel revenues, net of revenue taxes are projected to be $48.0 million, or 1.7% lower than the mid-course correction projection (Exhibit RBD-3, page 2, line 35, column 5). The $38.8 million under-recovery due to the increase in jurisdictional fuel costs and the $48.0 million under-recovery due to the decrease in jurisdictional fuel revenues result in the actual/estimated true-up under-recovery of $86.8 million (Exhibit RBD-3, page 2, line 44, column 5).

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

A. Below are the primary reasons for the $38.8 million variance.

<u>Fuel Cost of System Net Generation: $74.8 million increase (Exhibit RBD-3, page 2, line 2, column 5)</u>

The table below provides the detail of this variance.

Fuel Variance	2018 ACTUAL/ ESTIMATED	2018 MIDCOURSE CORRECTION	DIFFERENCE
Heavy Oil			
Total Dollar	$18,081,040	$1,380,944	$16,700,096
Units	1,540,386	119,963	1,420,423
$ per Units	11.7380	11.5114	0.2266
Variance Due to Consumption			$16,351,084
Variance Due to Cost			$349,012
Total Variance			$16,700,096
Light Oil			
Total Dollar	$23,252,266	$1,688,874	$21,563,393
Units	1,564,774	110,161	1,454,613
$ per Units	14.8598	15.3310	(0.4711)
Variance Due to Consumption			$22,300,605
Variance Due to Cost			($737,213)
Total Variance			$21,563,393
Coal			
Total Dollar	$61,474,973	$63,909,723	($2,434,750)
Units	25,345,757	26,543,078	(1,197,321)
$ per Units	2.4255	2.4078	0.0177
Variance Due to Consumption			($2,882,879)
Variance Due to Cost			$448,129
Total Variance			($2,434,750)
Gas			
Total Dollar	$2,773,198,972	$2,721,483,526	$51,715,445
Units	631,814,389	610,452,341	21,362,048
$ per Units	4.3893	4.4581	(0.0689)
Variance Due to Consumption			$95,235,054
Variance Due to Cost			($43,519,609)
Total Variance			$51,715,445

Fuel Variance	2018 ACTUAL/ ESTIMATED	2018 MIDCOURSE CORRECTION	DIFFERENCE
Nuclear			
Total Dollar	$174,817,401	$186,492,433	($11,675,032)
Units	302,463,140	305,610,510	(3,147,370)
$ per Units	0.5780	0.6102	(0.0322)
Variance Due to Consumption			($1,920,617)
Variance Due to Cost			($9,754,415)
Total Variance			($11,675,032)
Total			
Variance Due to Consumption			$62,766,991
Variance Due to Cost			$13,102,161
Total Variance			$75,869,152
Note: Fuel Cost of System Net Generation reflected above does not tie to amounts provided on the 2018 Actual/Estimated true-up schedules due to a reduction to nuclear fuel expense in the amount of $1.1 million due to an overstatement of nuclear fuel amortization.			

Fuel Cost of Stratified Sales: $5.3 million decrease (Exhibit RBD-3, page 2, line 3, column 5)

The variance for the fuel cost of stratified sales is primarily attributable to lower than projected MWh sales from stratified contacts due to variations in weather.

Railcar Lease (Cedar Bay/Indiantown/SJRPP): $3.8 million increase (Exhibit RBD-3, page 2, line 6, column 5)

The variance for the cost of railcar leases (Cedar Bay/Indiantown/SJRPP) is primarily attributable to the inclusion of the railcar lease associated with the St. Johns River Power Park transaction ("SJRPP Transaction") approved by Order No. PSC-2017-0415-AS-EI issued in Docket No. 20170123-EI on October 24, 2017.

Subsequent to the consummation of the SJRPP Transaction and as provided in the Asset Transfer and Contract Termination Agreement, FPL assumed responsibility for 50% of the railcar lease and related expenses. The cost of the SJRPP railcar lease was not included in the 2018 projections filing due to the timing of Commission approval.

SJRPP Fuel Inventory Expense: $1.6 million increase (Exhibit RBD-3, page 2, line 4, column 5)

The variance in SJRPP fuel inventory expense is associated with the difference between the value of actual unused coal inventory and an earlier estimate. The SJRPP fuel inventory expense of $4,996,469 (Exhibit RBD-3, page 2, line 4, column 3) represents the value of FPL's 20% ownership share of the actual unused coal inventory at the site subsequent to the consummation of the SJRPP Transaction and corresponding shutdown of the plant. The $3,436,627 (Exhibit RBD-3, page 2, line 4, column 4) reflected in the mid-course correction was based on the estimated fuel expense at that time.

Energy Cost of Economy Purchases: $19.8 million decrease (Exhibit RBD-3, page 2, line 11, column 5)

The variance for the energy cost of economy purchases is attributable to lower than projected economy purchases. FPL now projects economy purchases will be almost 643,000 MWh, or 690,000 fewer MWh than projected, resulting in a variance of $22.7 million. This variance is partially offset by $2.9 million due to higher than projected costs for economy purchases.

<u>Variable Power Plant O&M Avoided due to Economy Purchases: $0.5 million decrease (Exhibit RBD-3, page 2, line 17, column 5)</u>

The variance for variable power plant O&M related to economy purchases is attributable to lower than projected economy purchases. As described above, FPL now projects to purchase almost 690,000 fewer MWh of economy power.

<u>Gains from Off-System Sales: $15.1 million increase (Exhibit RBD-3, page 2, line 8, column 5)</u>

The variance for gains from off-system sales is attributable to higher than projected margins on economy sales. FPL now projects an average economy sales margin of $13.57/MWh, or $7.09/MWh higher than projected, resulting in a variance of $15.0 million. The remaining variance of $0.1 million is attributable to a slightly higher than projected volume of economy sales.

<u>Energy Payments to Qualifying Facilities: $6.5 million decrease (Exhibit RBD-3, page 2, line 10, column 5)</u>

The variance for energy payments to qualifying facilities is attributable to lower than projected As-Available energy purchases. FPL now projects that As-Available energy purchases will be nearly 232,000 MWh, or 335,000 MWh less than projected, resulting in a variance of $6.9 million. This variance is partially offset by $0.5 million due to higher than projected As-Available energy costs. The remaining variance of $0.2 million is attributable to lower than projected energy costs for Firm Co-Generation purchases, partially off-set by higher than projected Firm Co-Generation purchases.

<u>Other O&M Expense: $0.6 million increase (Exhibit RBD-3, page 2, line 26, column 5)</u>

The variance for other O&M expense is primarily attributable to a change in accounting treatment for annual nuclear fuel design software maintenance now being recorded as O&M, which was originally recorded to nuclear fuel as capital and amortized through Fuel Cost of Net Generation.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2018 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 2018 through December 2018.

Q. Please explain the calculation of the CCR 2018 actual/estimated true-up and the end-of-period net true-up amounts you are requesting this Commission to approve.

A. Exhibit RBD-4, pages 4 and 5 shows the actual/estimated capacity costs and applicable revenues (January 2018 through June 2018 reflects actual data, while the data for July 2018 through December 2018 is based on updated estimates) compared to the mid-course correction filing for the January 2018 through December 2018 period. The CCR revenues (net of revenue taxes) are projected to be $3,313,559 (Exhibit RBD-4, page 5, line 33, column 5) lower than FPL's mid-course correction projection. Jurisdictional total capacity costs are estimated to be $9,558,819 lower than the mid-course correction projection (Exhibit RBD-4, page 5, line 27, column 5). The $9,558,819 over-recovery due to lower jurisdictional capacity costs is partially offset by the $3,313,559 decrease in revenues, resulting in the 2018 actual/estimated true-up over-recovery amount of $6,415,909, including interest (Exhibit RBD-4, page 5, lines 38 plus 39, column 5).

As shown on Exhibit RBD-4, page 3, the 2018 end-of period net true up amount to be carried forward to the 2019 CCR factors is an over-recovery of $4,203,102 (line 15, column 15). This $4,203,102 net over-recovery is comprised of the 2017 final true-up under-recovery of $2,212,807 filed with the Commission on March 2, 2018 (line 12, column 15) and the actual/estimated true-up over-recovery, including interest, of $6,415,909 for the period January 2018 through December 2018 (lines 9 plus 10, column 15).

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

A. Yes.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-4, page 5, line 1, column 5, total system capacity costs are estimated to be $10.0 million or 3.7% less than projected in FPL's mid-course correction. The variance related to the jurisdictional portion of these costs is a 3.7% decrease from the mid-course correction projections (page 5, line 27, column 5).

Below are the primary reasons for the estimated $10.0 million decrease in total system capacity costs.

<u>Payments to Non-Cogenerators: $5.9 million decrease (Exhibit RBD-4, page 4, line 1, column 5)</u>

The variance for payments to non-cogenerators (SJRPP, Solid Waste Authority, Exelon Generation Company, LLC., Orlando Utilities Commission ("OUC")) is primarily attributable to lower than projected costs of approximately $8.4 million associated with the SJRPP agreement during the first half of the year. Approximately $8.8 million reflects a one-time entry to reverse accrued expenses associated with JEA Debt Service, Transmission Capability and Service, and Cumulative Capital Recovery Amounts. The remaining variance of $0.4 million is related to fixed O&M expenses which have been declining since the plant was taken offline in January 2018. No additional capacity costs have been projected for the remaining period. The lower SJRPP costs are offset by approximately $2.5 million associated with the new OUC Purchased Power Agreement that will begin in October 2018.

<u>Incremental Plant Security O&M Costs: $2.9 million decrease (Exhibit RBD-4, page 4, line 6, column 5)</u>

The variance for incremental plant security costs is primarily due to lower than projected Homeland Security Fees and personnel costs at the St. Lucie and Turkey Point Plants.

<u>Transmission Revenues from Capacity Sales: $1.7 million increase (Exhibit RBD-4, page 4, line 11, column 5)</u>

The variance for transmission revenues from capacity sales is primarily attributable to revenues from capacity premiums associated with power capacity sales. Higher than projected revenues from capacity premiums resulted in a variance of approximately $2.3 million. This variance was partially offset by approximately $0.6 million due to lower than projected transmission revenues from economy sales.

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 in Docket 20180001-EI?

A. Yes. The capital structure components and cost rates used to calculate the rate of return on capital investments for the period January 2018 through December 2018 are included on pages 15 and 16 of Exhibit RBD-4.

Q. Was the jurisdictional separation factor used for General Plant costs in this filing approved in Final Order No. PSC-2018-0028-FOF-EI ("2018 Final Order") issued on January 8, 2018?

A. No. The CCR projections filed by FPL in Docket 20170001-EI did not include any costs for General Plant; therefore, the General Plant separation factor was not addressed in the 2018 Final Order. However, FPL has incurred actual costs associated with General Plant for Incremental Plant Security Capital Costs during 2018. Therefore, FPL has utilized the General Plant separation factor shown on my Exhibit RBD-4, pages 17 and 18. This is consistent with the other separation factors approved for use in the 2018 Final Order. The appropriate 2018 separation factor for General Plant (Demand) is 96.9449%.

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. 20180001-EI

AUGUST 24, 2018

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 of Clause Recovery and Wholesale Rates 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 Fuel Cost Recovery ("FCR") Clause factors for three periods: (i) January 2019 through February 2019, (ii) March 2019 through May 2019, reflecting the fuel savings associated with the 2019 solar photovoltaic project that is expected to enter commercial operation by March 1, 2019 ("2019 Solar Project"), and (iii) June 2019 through December 2019, reflecting the fuel savings associated with the Okeechobee Clean Energy Center ("OCEC"), which is expected to enter commercial operation by June 1, 2019;

- The 2019 FCR factors based on the traditional factor calculation method, which spreads the fuel savings associated with the 2019 Solar Project and OCEC over the entire calendar year, for informational purposes;
- The calculation of the jurisdictional amount of FPL's portion of the 2017 incentive mechanism gains for recovery through the 2019 FCR factors;
- The Capacity Cost Recovery ("CCR") Clause factors for the period January 2019 through December 2019 and the CCR factors for the same period, including an adjustment to recover the non-fuel revenue requirements associated with the Indiantown Cogeneration L.P. facility ("Indiantown"), 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 2019 through December 2019; 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 2019 through February 2019, which exclude fuel savings for the 2019 Solar Project and OCEC expected to be placed in service by March 1, 2019 and June 1, 2019, respectively;

- Schedules E1-A, E1-C, E1-D, Calculation of Jurisdictional Incentive Mechanism Gains – FPL Portion, and H1, which pertain to the entire 2019 calendar year;
- Pages 9 through 12, which provide the 2019 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 2019 through May 2019, which include fuel savings for the 2019 Solar Project and exclude fuel savings for OCEC expected to be placed in service by June 1, 2019;

Exhibit RBD-7 (Appendix IV)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation, and E10 for the period June 2019 through December 2019, which include fuel savings for the 2019 Solar Project and OCEC;

Exhibit RBD-8 (Appendix V)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 that provide the calculation of FCR factors for the period January 2019 through December 2019 based on the traditional factor calculation methodology, which spreads fuel savings for the 2019 Solar Project and OCEC over the entire calendar year;

Exhibit RBD-9 (Appendix VI)

- Pages 1 through 4 provide the calculation of the 2019 CCR factors excluding the Indiantown non-fuel revenue requirements for January 2019 through December 2019;
- Pages 5 through 9 provide the calculation of depreciation and return on incremental power plant security and incremental Nuclear Regulatory Commission ("NRC") compliance capital investments;
- Page 10 provides the calculation of amortization and return on the regulatory asset related to the Cedar Bay Transaction;
- Page 11 provides the calculation of amortization and return on the regulatory liability related to the Cedar Bay Transaction;
- Page 12 provides the calculation of amortization and return on the regulatory asset related to Indiantown;
- Page 13 provides the calculation of amortization and return on the regulatory asset and liability related to St. Johns River Power Park, and the refund to customers associated with the deferred interest liability and dismantlement;
- Page 14 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 2019 through December 2019;
- Pages 17 and 18 provide the calculation of the portion of the CCR factors that recovers the non-fuel revenue requirements associated with

Indiantown for the period January 2019 through December 2019;

- Page 19 combines the results from pages 1 through 4 and pages 17 and 18 to provide the total 2019 CCR factors including the non-fuel revenue requirements associated with Indiantown for the period January 2019 through December 2019;
- Pages 20 and 21 provide the calculation of the Indiantown revenue requirements for January 2019 through December 2019;
- Pages 22 through 31 provide the calculations of stratified separation factors.

FUEL COST RECOVERY CLAUSE

Q. What adjustments are included in the calculation of the 2019 FCR factors shown on Schedules E1 included in Appendices II through V?

A. The 2019 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 2017 incentive mechanism gains. The total net true-up to be included in the 2019 FCR factors is an under-recovery of $111,740,516, as shown on line 30 of Schedule E1.

The GPIF testimony of witness Charles R. Rote, filed on March 15, 2018, proposes a reward of $5,857,941 for the period ending December 2017, as shown on line 34 of Schedule E1.

FPL is including $2,204,548 for the jurisdictional amount associated with its share of 2017 incentive mechanism gains in the calculation of its 2019 FCR factors, as shown on line 35 of Schedule E1.

As presented and explained in the direct testimony and exhibits of FPL witness Gerard J. Yupp filed on March 2, 2018 in this docket, FPL's activities under the incentive mechanism in 2017 delivered $43,861,831 in total gains. Of these total gains, FPL is allowed to retain $2,317,099 (system amount) per Order No. PSC-13-0023-S-EI dated January 14, 2013 and Order No. PSC-16-0560-AS-EI dated December 15, 2016. FPL will reflect recovery of one-twelfth of the approved jurisdictional amount of $2,204,548, net of revenue taxes, in each month's Schedule A2 for the period January 2019 through December 2019 as a reduction to jurisdictional fuel revenues applicable to each period. The calculation of the jurisdictional amount of the 2017 incentive mechanism gains adjusted for revenue taxes is shown on page 4 of Appendix II.

Q. Please explain the adjustment reflected on line 4 of Schedule E1 related to the fuel cost of stratified sales.

A. FPL has included a credit of $21,588,417 associated with two stratified wholesale power sales contracts in effect in 2019: (1) a 200 MW intermediate power contract with Seminole Electric Cooperative Inc., and (2) a combined intermediate/peaking power contract with Florida Public Utilities Company ("FPUC"). The fuel costs charged to Seminole 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 2019 FCR Factors

Q. Please explain how FPL has calculated its proposed FCR factors for the period January 2019 through December 2019 to reflect the impact of the fuel savings associated with the 2019 Solar Project and OCEC.

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 2019 Solar Project. The SoBRA (associated with the 2019 Solar Project) is expected to be implemented by March 1, 2019. Additionally, in the 2016 Base Rate Settlement Agreement, the Commission approved FPL's recovery of annualized non-fuel revenue requirements associated with OCEC contemporaneously with the in-service date of the unit, which is expected to occur by June 1, 2019. FPL proposes that the corresponding fuel savings associated with the 2019 Solar Project and OCEC be reflected in the FCR factors concurrent with the SoBRA and OCEC generation base rate adjustment ("GBRA") 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 2019 Solar Project and/or OCEC impact the FCR factors?

A. At this time, FPL does not anticipate a delay in the commercial operation dates of the 2019 Solar Project or OCEC. 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). FPL will not implement the SoBRA or OCEC GBRA until those units go into service.

Q. What are the projected 2019 fuel savings associated with the 2019 Solar Project and OCEC?

A. As explained in the testimony of FPL witness Yupp, the projected 2019 fuel savings associated with the 2019 Solar Project and OCEC are $22,295,402 and $114,444,649, respectively.

Q. Please explain the calculation of 2019 FCR factors reflecting the fuel savings associated with the 2019 Solar Project and OCEC.

A. FPL first calculates the FCR factors for January 2019 through February 2019 that exclude the fuel savings associated with the 2019 Solar Project and OCEC. These FCR factors assume the 2019 Solar Project and OCEC are not yet operating and therefore exclude the associated fuel savings. These adjustments are reflected on lines 2 and 3 of Schedule E1 in Appendix II. The levelized FCR factor for January 2019 through February 2019 including these adjustments is 2.735 cents per kWh. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $24.12 during this period.

Next, FPL calculates the FCR factors for March 2019 through May 2019 that include the fuel savings associated with the 2019 Solar Project that is scheduled to go in-service by March 1, 2019. This adjustment is shown on line 36 of Schedule E1 in Appendix III. These FCR factors assume OCEC is not yet operating and therefore exclude that plant's associated fuel savings. This adjustment is shown on line 3 of Schedule E1 in Appendix III. The levelized FCR factor for March 2019 through May 2019 including this adjustment is 2.712 cents per kWh. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $23.89 for this period.

Finally, FPL calculates FCR factors for June 2019 through December 2019 that include the fuel savings associated with OCEC during this period. This adjustment is shown on line 37 of Schedule E1 in Appendix IV. The FCR factors for June 2019 through December 2019 include the fuel savings associated with both the 2019 Solar Project (line 36 of Schedule E1) and OCEC. The levelized FCR factor for June 2019 through December 2019 is 2.551 cents per kWh. For FPL's residential 1,000 kWh bill, this represents a fuel charge of $22.27 for this period.

Schedule E2 provides the monthly fuel factors as well as 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 2019?

A. Yes. Although FPL requests approval of separate FCR factors for each of the three periods, reflecting the impact of the 2019 Solar Project and OCEC in those periods, FPL provides for informational purposes the calculation of a twelve-month levelized fuel factor for 2019. Appendix V includes Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10, which calculate a twelve-month levelized fuel factor of 2.614¢ per kWh by including the fuel savings for the 2019 Solar Project and OCEC throughout the twelve months of 2019.

CAPACITY COST RECOVERY CLAUSE

Q. Have you prepared a summary of the requested capacity costs for the projected period of January 2019 through December 2019?

A. Yes. Pages 1 and 2 of Appendix VI provides this summary. Total recoverable capacity costs for the period January 2019 through December 2019 are $256,396,121 (page 2, line 39). This includes $260,414,750 for 2019 projected jurisdictional capacity costs, the net true-up over-recovery for 2017 and 2018 of $4,203,102 (line 35 plus line 36) and revenue taxes but excludes the 2019 Indiantown non-fuel revenue requirements.

Q. What are the projected Indiantown jurisdictional non-fuel revenue requirements for the January 2019 through December 2019 period?

A. The jurisdictional non-fuel revenue requirements for January 2019 through December 2019 are $3,304,628. The calculation of this amount is shown on Exhibit RBD-9, Appendix VI. 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 2019 CCR factors by rate class including an adjustment to recover the non-fuel revenue requirements associated with Indiantown for the period January 2019 through December 2019?

A. Yes. As approved in Order No. PSC-16-0506-FOF-EI, FPL has included on pages 17 and 18 of Exhibit RBD-8, Appendix VI, the 2019 non-fuel revenue requirements associated with Indiantown of $3,304,628. Accordingly, page 19 of Exhibit RBD-8, Appendix VI, shows the calculation of the 2019 CCR factors including the non-fuel revenue requirements associated with Indiantown for the period January 2019 through December 2019.

Q. Has FPL accounted for stratified wholesale power sales contracts in the jurisdictional separation of projected 2019 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's sales forecast includes two stratified wholesale power sales contracts in effect in 2019. The stratified separation factors were calculated in a manner consistent with the separation factors used for the non-nuclear contracts (now expired) in prior base rate cases and are provided in Appendix VI, pages 22-31.

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

A. Yes. Page 3 of Appendix VI 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 dates is FPL requesting for the new FCR and CCR factors?

A. FPL is requesting that the January 2019 FCR factors and the CCR factors for the period January 2019 through December 2019 become effective starting with meter readings made on January 1, 2019. FPL is also requesting that the FCR factors for the periods March 2019 through May 2019 and June 2019 through December 2019 become effective coincident with the in-service dates of the 2019 Solar Project and OCEC, which are expected to be by March 1, 2019 and June 1, 2019, respectively. These factors should remain in effect until modified by this Commission.

Proposed 2019 Residential Bill

Q. What is FPL's proposed residential 1,000 kWh bill for the period January 2019 through December 2019?

A. FPL's proposed residential 1,000 kWh bill for January 2019 through February 2019 is $100.42. This proposed bill includes a base rate charge of $66.88, an FCR charge of $24.12, a CCR charge of $2.58, an environmental cost recovery charge of $1.59, a conservation cost recovery charge of $1.50, a storm charge of $1.24, and gross receipts tax of $2.51.

Once the 2019 Solar Project is placed in-service, projected to be by March 1, 2019, FPL's base rate charge will increase to $67.41 to reflect the application of the SoBRA, consistent with the 2016 Base Rate Settlement Agreement and the FCR charge will decrease to $23.89 to include the associated fuel savings. FPL's proposed residential 1,000 kWh bill for the period March 2019 through May 2019 is $100.73.

Once OCEC is placed in-service, projected to be by June 1, 2019, FPL's base rate charge will increase to $69.46 to reflect the application of the OCEC adjustment, consistent with the 2016 Base Rate Settlement Agreement and the FCR charge will decrease to $22.27 to include the associated fuel savings. FPL's proposed residential 1,000 kWh bill for the period June 2019 through December 2019 is $101.17.

FPL's proposed residential 1,000 kWh bills for 2019 are provided on Schedule E-10, which is page 7 of Appendix IV.

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. 20180001-EI

MARCH 2, 2018

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. Finally, I am responsible for the oversight of FPL's optimization activities associated with the Incentive Mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the 2017 results of FPL's activities under the Incentive Mechanism that was originally approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI and approved for continuation with certain modifications by Order No. PSC-16-0560-AS-EI, dated December 15, 2016, in Docket No. 160021-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 4 pages:
  - Page 1 – Total Gains Schedule
  - Page 2 – Wholesale Power Detail
  - Page 3 – Asset Optimization Detail
  - Page 4 – Incremental Optimization Costs

Q. Please provide an overview of the Incentive Mechanism.

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. 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 through a third party in the form of an Asset Management Agreement ("AMA").

Q. Please describe the modifications that were made to the Incentive Mechanism in FPL's 2016 rate case and approved by Order No. PSC-16-0560-AS-EI.

A. There were two specific modifications made to the Incentive Mechanism in FPL's 2016 rate case. First, the sharing threshold was reduced from $46 million to $40 million. The sharing intervals and percentages remained unchanged from the original Incentive Mechanism. Under the modified Incentive Mechanism, customers will continue to receive 100% of the gains up to the new sharing threshold of $40 million. Incremental gains above $40 million will continue to be shared between FPL and customers as follows: customers receive 40% and FPL receives 60% of the incremental gains between $40 million and $100 million; and customers receive 50% and FPL receives 50% of all incremental gains above $100 million.

The second modification that was made to the Incentive Mechanism involved variable power plant O&M costs. Under the original Incentive Mechanism, FPL was allowed to recover 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). Under the modified Incentive Mechanism, FPL will net economy sales and purchases and recover the net amount of variable power plant O&M incurred during the year. For example, if economy purchases are greater than economy sales, customers will receive a credit for the net variable power plant O&M that has been saved during the year. The per-MWh variable power plant O&M rate that FPL will use to calculate these costs, as described in FPL's 2017 Test Year MFR's filed with the 2016 Rate Petition will be $0.65/MWh. FPL continues to be 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.

Q. Please summarize the activities and results of the Incentive Mechanism for 2017.

A. FPL's activities under the Incentive Mechanism in 2017 delivered $43,861,831 in total gains. During 2017, 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. Additionally, FPL entered into several AMAs related to a small portion of upstream gas transportation during 2017. The total gains of $43,861,831 exceeded the sharing threshold of $40 million. Therefore, the gains above $40 million will be shared between customers and FPL, 40% and 60%, respectively. Exhibit GJY-1, Page 1, shows monthly gain totals, threshold levels and the final gains allocation for 2017.

Q. Please provide the details of FPL's wholesale power activities under the Incentive Mechanism for 2017.

A. The details of FPL's 2017 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-1. FPL had gains of $17,277,542 on wholesale sales and savings of $7,821,480 on wholesale purchases for the year.

Q. Please provide the details of FPL's asset optimization activities under the Incentive Mechanism for 2017.

A. The details of FPL's 2017 asset optimization activities are shown on Page 3 of Exhibit GJY-1. FPL had a total of $18,762,809 of gains that were the result of seven different forms of asset optimization.

Q. Did FPL engage in any new forms of asset optimization during 2017?

A. No. FPL did not engage in any new forms of asset optimization activities during 2017.

Q. Did FPL incur incremental O&M expenses related to the operation of the Incentive Mechanism in 2017?

A. Yes. FPL incurred personnel expenses of $425,123 related to an additional two and one-half personnel required to support FPL's expanded activities under the

Incentive Mechanism. FPL also incurred $278,801 in expenses related to licensing fees of OATI WebTrader software and a collaborative working engagement with Accenture LLP. In total, FPL incurred incremental O&M expenses related to the operation of the Incentive Mechanism of $703,923 in 2017.

On the variable power plant O&M side, FPL's actual net economy power sales totaled 1,341,059 MWh (i.e., 1,962,498 MWh of economy sales, less 621,439 MWh of economy purchases). This resulted in net variable power plant O&M costs of $871,688 for 2017.

Q. Overall, were FPL's activities under the Incentive Mechanism successful in 2017?

A. Yes. FPL's activities under the Incentive Mechanism were highly successful in 2017. On the wholesale power side, suitable market conditions in the winter period 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 capitalize on power market opportunities throughout the year to deliver slightly more than $25 million in customer benefits. Asset optimization activities related to natural gas resulted in significant customer benefits of more than $18.5 million. In total, these activities delivered $43,861,831 of gains, which contrast very favorably to the total optimization expenses (personnel and variable power plant O&M) of $1,575,612.

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. 20180001-EI

APRIL 3, 2018

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 data on FPL's hedging activities, by month, for calendar year 2017. 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. While the settlement agreement approved in Order No. PSC-16-0560-AS-EI for FPL's 2016 rate case provided for FPL to terminate natural gas financial hedging prospectively for the agreement's Minimum Term, it recognized that FPL already had placed hedges for 2017 in accordance with its approved Risk Management Plan. My testimony addresses the results of those hedges.

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 Exhibit GJY-2 – 2017 Hedging Activity True-Up (Pages 1 through 13).

Q. Does your Exhibit GJY-2 provide the detail on FPL's 2017 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-2.

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 2017, FPL implemented a well-disciplined, well-defined and well-controlled hedging program in compliance with FPL's 2016 Risk Management Plan that was approved by the Commission in Order No. PSC-15-0586-FOF-EI issued on December 23, 2015.

Q. Please summarize FPL's 2017 hedging activities.

A. Consistent with its approved 2016 Risk Management Plan, FPL hedged a portion of its natural gas fuel portfolio for 2017 utilizing financial swaps.

Overall, actual 2017 natural gas prices settled, on average, approximately $0.12 per MMBtu higher than the forward prices that were in effect when FPL was executing its financial swaps for 2017. As would be expected under the approved hedging approach, this increase in natural gas prices resulted in reported natural gas hedging savings for the year of $37,833,753, as shown on Exhibit GJY-2.

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. 20180001-EI

AUGUST 24, 2018

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. Additionally, my testimony addresses the Incentive Mechanism results for 2017 and the Incremental Optimization Costs included in FPL's 2019 Projection Filing pursuant to the Incentive

Mechanism that was approved in Order No. PSC-16-0560-AS-EI dated December 15, 2016 ("2016 Base Rate Settlement Agreement"). 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 March 1, 2019 and the projected fuel savings resulting from the commercial operation of the Okeechobee Clean Energy Center ("OCEC") estimated to be placed into service on June 1, 2019.

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-3: Appendix I

and I am co-sponsoring:

- Schedules E2 through E9 of Appendix II included in Renae Deaton's Exhibit RBD-5 and Schedule E2 of Appendix III, IV, and V included in Renae Deaton's Exhibits RBD-6, RBD-7, and RBD-8 respectively.

<u>FUEL PRICE FORECAST</u>

Q. What forecast methodologies has FPL used for the 2019 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 27, 2018 for its 2019 projection filing, which is the most current information that could be incorporated into FPL's schedule for calculating the 2019 Fuel Cost Recovery ("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 2019 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 2018 Short-Term Energy Outlook, the Energy Information Administration ("EIA") forecasts Henry Hub natural gas spot prices to average approximately $2.99 per MMBtu in 2018 and $3.04 per MMBtu in 2019. The EIA expects production growth to continue in 2019 due to improved drilling efficiency and cost reductions, as well as higher crude oil prices that contribute to higher associated gas production from oil-directed rigs. Natural gas production is estimated to grow by an average rate of nearly 11% in 2018 (compared to 2017 levels) and 4% in 2019 (compared to 2018 levels).

Total natural gas consumption is forecast to increase by 7% in 2018 before slightly decreasing in 2019. For 2018, increases in natural gas consumption are mainly due to higher use in the electric power sector. The increase in 2018 also reflects higher residential and commercial demand due to colder weather in the first quarter of 2018 compared to the first quarter of 2017. Natural gas consumption in the residential and commercial sectors is forecast to decrease in 2019, reflecting more moderate winter weather. Power sector consumption is projected to remain relatively flat in 2019 compared to 2018 levels and industrial demand is expected to increase in 2018 as new chemical projects come on-line and then remain flat in 2019. Overall, total natural gas consumption in 2019 is projected to remain relatively flat to 2018 consumption levels. Natural gas storage levels ended March at roughly 1.4 trillion cubic feet, or 19% lower than the five-year average. Natural gas storage levels are expected to reach approximately 3.5 trillion cubic feet at the end of October 2018, which would be 9% lower than the five-year average level for the end of

October. However, higher natural gas production during the injection season will help offset low storage levels and moderate upward price pressures.

Q. Please describe FPL's natural gas transportation portfolio for the January through December 2019 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 2019 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 billion cubic feet ("BCF") of firm natural gas storage capacity in Bay Gas Storage, located in southwest Alabama and 1.0 BCF of firm natural gas storage capacity in Southern Pines Energy Center, located in southeast Mississippi. 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 13% 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 2019 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 2019 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.

In its July 2018 Short-Term Energy Outlook report, the EIA forecasts West Texas Intermediate crude oil prices will average approximately $65.95 per barrel in 2018 and $62.04 per barrel in 2019. The EIA anticipates global crude oil and other liquid fuels production to grow by 2.15 million barrels per day in 2018 and 2.38 million barrels per day in 2019, with consumption growing by approximately 1.72 million barrels per day in 2018 and 2019. U.S. crude oil and liquid fuels production is projected to increase by roughly 0.47 million barrels per day in 2018 and 0.33 million barrels per day in 2019. 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 2019 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 2019 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 Plant Scherer?

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

Q. Please provide FPL's projection for the dispatch cost of coal at Plant Scherer for the January through December 2019 period.

A. FPL's projection for the system average dispatch cost of coal for this period, 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 2019?

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 2019.

Q. Please describe the significant planned outages for the January through December 2019 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. Turkey Point Unit 4 is scheduled to be out of service from March 11, 2019 until April 25, 2019, or 45 days during the period. St. Lucie Unit 1 is scheduled to be out of service from September 2, 2019 until October 2, 2019, or 30 days during the period.

Q. Please identify any changes to FPL's fossil generation capacity projected to take place during the January through December 2019 period.

A. As shown in FPL's 2018 Ten Year Power Plant Site Plan (Table ES-1, page 12), FPL projects a net increase in its 2019 summer firm capacity of 516 MW. Significant increases to FPL's fossil generation capacity include the addition of 1,778 MW of combined cycle generation at OCEC, roughly 750 MW of capacity upgrades at a number of FPL's existing combined cycle units, and the addition of 164 MW of solar generation. Significant decreases to FPL's fossil generation capacity include the retirement of Martin Unit No. 1 and Unit No. 2 (1,626 MW) and Fort Lauderdale Unit No. 4 and Unit No. 5 (884 MW).

<u>WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS</u>

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2019?

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.

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 2,191,635 MWh of wholesale (off-system) power sales for the period of January through December 2019. The projected fuel cost related to these sales is $53,834,986. The projected transaction revenue from these sales is $79,091,499. After taking into account the transmission costs for those sales, the projected gain is $19,812,410.

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 2019 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 550,475 MWh at a cost of $14,167,400. If FPL generated this energy, FPL estimates that it would cost $16,914,474. Therefore, these purchases are projected to result in savings of $2,747,074.

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 Orlando Utilities Commission ("OUC") for the October 1, 2018 through December 31, 2020 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. 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 2019 period.

A. Energy purchases under the SWA agreements are projected to be 788,160 MWh for the period at an energy cost of $26,207,744. Energy purchases from OUC are projected to be 99,094 MWh for the period at an energy cost of $3,630,264. 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 539,928 MWh at a cost of $2,956,007. 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 281,675 MWh at a cost of $5,961,696.

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 578,131 MWh of energy at a cost of $3,094,298. These projections are shown on Schedule E6 of Appendix II.

<u>HEDGING/ RISK MANAGEMENT PLAN</u>

Q. Has FPL filed a comprehensive risk management plan for 2019, 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 Final True-Up 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 Final True-Up Report for 2017 (January through December) on April 3, 2018.

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

A. Yes. FPL's hedging strategies were 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 2017?

A. FPL's asset optimization activities in 2017 delivered total benefits of $43,861,831. The total gains exceeded the sharing threshold of $40 million and, therefore, the gains above $40 million will be shared between customers and FPL on a 40%/60% basis, respectively. In total, customers will receive $41,244,745 (net of FPL's share of the gain above the $40 million threshold, and after incremental personnel, software, and hardware expenses are removed), and FPL will receive $2,317,099. FPL's share of the gain is included for recovery in FPL's 2019 FCR Clause factors.

Q. Did the Incentive Mechanism allow FPL to deliver greater value to customers in 2017?

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 $26.4 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 $26.4 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 nearly $18.8 million of additional savings in 2017. When one takes into account these additional savings, less FPL's recovery of incremental optimization costs, the result is that FPL's customers received $41.2 million of savings under the Incentive Mechanism. This is $14.8 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 FPL included in its 2019 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 2019.

Q. Has FPL included in its 2019 FCR factors, projections of the Incremental Optimization Costs that it will incur under the Incentive Mechanism?

A. Yes. FPL has included in its 2019 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 $449,942 in 2019 for the salaries and expenses related to employees who were added in 2013 to support the Incentive Mechanism. FPL is also projecting to incur $59,222 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 2019 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 2,191,635 MWh and purchase 550,475 MWh of economy power. Therefore, applying FPL's VOM rate of $0.65/MWh, FPL projects to incur VOM expenses of $1,424,563 associated with its economy sales and to avoid ($357,809) with its economy purchases. FPL has included for recovery the net of these two figures, $1,066,754 (Schedule E2, Sum of Line Nos. 14 and 15), in its 2019 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 2019.

A. The PV generation will consist of four solar energy centers ("the 2019 Project") located at four sites. The four solar energy centers are sized to generate a total of 298 MW (nameplate capacity) and are scheduled to go into service by March 1, 2019. These four sites consist of Miami-Dade, Interstate, Pioneer Trail, and Sunshine Gateway.

Q. Will the operation of PV generation during 2019 result in fuel savings for FPL's customers?

A. Yes. For the March through December 2019 period, the operation of the 2019 Project is projected to result in fuel savings for FPL's customers of $22,295,402.

Q. How did FPL calculate the projected fuel savings associated with the operation of the 2019 Project?

A. FPL utilized its GenTrader model to quantify the fuel savings associated with the operation of the 2019 Project. 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 two separate production cost simulations, one without the 2019 Project and one with the 2019 Project. A comparison of the total system fuel costs from GenTrader for the two simulations showed that the fuel costs were $22,295,402 lower in the case that included the 2019 Project than in the case without the 2019 Project.

<u>CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE COMMERCIAL OPERATION OF OCEC</u>

Q. Will the operation of OCEC during 2019 result in fuel savings for FPL's customers?

A. Yes. This unit's high efficiency creates substantial fuel savings for FPL's customers. For the June through December 2019 period, the operation of OCEC is projected to result in fuel savings for FPL's customers $114,444,649.

Q. How did FPL calculate the projected fuel savings associated with the operation of OCEC?

A. FPL utilized its GenTrader model to quantify the fuel savings associated with the operation of OCEC. 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 OCEC fuel savings. In order to calculate the OCEC fuel savings, FPL ran two separate production cost simulations, one without OCEC and one with OCEC. A comparison of the total system fuel costs from GenTrader for the two simulations showed that the fuel costs were $114,444,649 lower in the case that included OCEC than in the case without OCEC.

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. 20180001-EI

AUGUST 24, 2018

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 Training and Special Projects in the Nuclear Business Unit.

Q. Please describe your duties and responsibilities.

A. I am responsible for the Nuclear fleet functional area of Training and oversee Special Projects.

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 31 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, Vice President of Organizational Effectiveness and Learning to my current role of Vice President of Training and Special Projects.

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 (Million British Thermal Units or "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 2019 through December 2019. I am also supporting FPL's projected 2019 incremental plant security and Fukushima costs. Finally, I address 2018 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 the nuclear units and current operating schedules, for the period January 2019 through December 2019.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2019 through December 2019.

A. FPL projects the nuclear units will burn 301,929,301 MMBtu of energy at a cost of $0.5502 per MMBtu for the period January 2019 through December 2019. 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 its nuclear power plants for the period January 2019 through December 2019?

A. FPL projects that it will incur $35.6 million in incremental nuclear power plant security costs in 2019. The costs consist of $8 million of capital expenditures and $29.8 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 the 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; maintenance of 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 its nuclear power plants for the period January 2019 through December 2019?

A. FPL's current projection of Fukushima-related costs for 2019 is approximately $1.0 million of O&M expenses and $8.5 million of capital 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 2019:

- 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; and
- Replacement of Turkey Point Unit 4 A, B and C Reactor Coolant Pump ("RCP") seals during the Spring 2019 outage.

Turkey Point RCP Seals

Q. Please provide a brief description of the Turkey Point RCP seal replacement.

A. To comply with Fukushima Station Blackout mitigation requirements, FPL is replacing the RCP seals at Turkey Point Unit 3 and 4 with Flowserve low leakage RCP Seals. RCP seal injection is lost during a station blackout. The prior RCP seals would stop functioning following the loss of injection pressure, resulting in excessive Reactor Coolant System ("RCS") leakage. The new RCP seals are designed to greatly reduce the RCS inventory loss and thus provide more robust protection against any impairment of core-cooling capacity.

Q. When did FPL replace the RCP seals at the Turkey Point site?

A. The Turkey Point Unit 3 A, B and C RCP seals were replaced initially during the Fall 2015 outage, and the Unit 4 seals were replaced during the Spring of 2016. FPL has subsequently replaced the Unit 3 A and B seals in March 2017, the C seal in November 2017 and is planning to replace all three seals in the upcoming Fall outage in October 2018. Unit 4 has subsequently replaced the A and B RCP seals in November 2017 and is planning to replace all three seals in the Spring 2019 outage.

Q. Why is FPL replacing the RCP seals at Turkey Point more frequently than originally planned?

A. Turkey Point had been experiencing premature wear leading to failures of the seals. Flowserve had been put on formal notice for these failures and it investigated the cause of the premature wear.

Q. Has Flowserve determined the cause of the premature wear?

A. Flowserve has completed their initial testing and has identified a design flaw as a material and closure force issue. The material is producing a self-induced electro-corrosion reaction and the closing forces of the seal are cracking the seal face. Flowserve is currently testing a new design to replace the existing RCP seal design at Turkey Point. Since the new design will not be ready for the Unit 3 Fall outage, FPL will be replacing the existing seals with the current design until the new design is available. Currently, it is unknown whether the new design will be available for the Unit 4 RCP seal replacement planned in Spring 2019.

Q. What is the estimated cost to replace the RCP seals for Unit 3 and Unit 4 during the Fall 2018 and Spring 2019 outages?

A. FPL estimates the cost to replace the RCP seals to be approximately $8.5 million for each unit.

Q. Has FPL filed a warranty claim with Flowserve for the degraded RCP seals?

A. Yes. FPL will not be charged for the cost of the replacement seals. As with any major nuclear work contract, however, there are limits to the vendor's liability. Under the Flowserve contract, FlowServe is not responsible for labor and other costs that are incurred as part of the replacement.

Q. Did FPL have other options to replace the RCP seals?

A. Yes. FPL evaluated a number of viable options and concluded that the Flowserve RCP seals were the most cost-effective option that met the Fukushima Station Blackout mitigation requirements and did not require expensive modifications or replacement of the Reactor Coolant Pump Shafts. Additionally, there were other factors that favored Flowserve's cartridge seal design, such as improved seal reliability, a longer life span compared to other designs, and the ability to be assembled outside the containment and be tested prior to installation which reduces the risk of failure and limits outage duration.

<u>2018 Unplanned Outage Events</u>

Q. Has FPL experienced any unplanned outages at its St. Lucie plant in 2018?

A. No, St. Lucie has not experienced any unplanned outages in 2018.

Q. Has FPL experienced any unplanned outages at its Turkey Point plants in 2018?

A. No, Turkey Point has not experienced any unplanned outages in 2018.

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. 20180001-EI

MARCH 15, 2018

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 Business Services Manager in the Power Generation Division.

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. Since January 2013, I have also overseen the 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 FPL's actual 2017 performance for Equivalent Availability Factor ("EAF") and Average Net Operating Heat Rate ("ANOHR") for the twelve generating units used to determine its 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-2018-0028-FOF-EI issued January 8, 2018 for the period January through December 2017, and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the result of these calculations: $11,716,743 of fuel savings to FPL's customers as a results of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $5,857,941.

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 in general terms how the total GPIF reward/penalty amount was calculated.

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 +1.9677, $11,716,743 in fuel savings and a GPIF reward of $5,857,941. 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 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 twelve 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 19. These tables are based on the targets and target ranges previously 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 19. These tables are based on the targets and target ranges approved by the Commission.

Q. Please explain the primary reason FPL will receive a reward under the GPIF for the January through December 2017 period.

A. The primary reason that FPL will receive a reward for the period is that adjusted actual EAFs for nine out of the twelve GPIF units were better than their targets. In addition, two out of the twelve 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.

A. St. Lucie Unit 1 operated at an adjusted actual EAF of 97.5%, compared to its target of 93.6%. This results in +10.0 points, which corresponds to a GPIF reward of $2,593,011.

St. Lucie Unit 2 operated at an adjusted actual EAF of 89.2%, compared to its target of 83.7%. This results in +10.0 points, which corresponds to a GPIF reward of $1,881,496.

Turkey Point Unit 3 operated at an adjusted actual EAF of 86.8% compared to its target of 85.1%. This results in +5.67 points, which corresponds to a GPIF reward of $1,085,432.

Turkey Point Unit 4 operated at an adjusted actual EAF of 89.4% compared to its target of 85.4%. This results in +10.0 points, which corresponds to a GPIF reward of $2,030,348.

In total, the nuclear units' EAF performance results in a GPIF reward of $7,590,287.

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

A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,399 Btu/kWh compared to its target of 10,401 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 10,283 Btu/kWh compared to its target of 10,278 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 11,003 Btu/kWh compared to its target of 11,106 Btu/kWh. This ANOHR is better than the ±75 Btu/kWh dead band around the projected target. This results in +2.67 points, which corresponds to a GPIF reward of $97,647.

Turkey Point Unit 4 adjusted actual ANOHR is 10,932 Btu/kWh compared to its target of 11,019 Btu/kWh. This ANOHR is better than the ±75 Btu/kWh dead band around the projected target. This results in +1.62 points, which corresponds to a GPIF reward of $47,633.

In total, the nuclear units' heat rate performance results in a GPIF reward of $145,280.

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

A. $7,735,567.

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

A. Regarding EAF performance, five of the eight fossil generating units performed better than their availability targets resulting in a combined reward of $1,683,522 while the other three performed worse than their availability targets resulting in a combined penalty of $793,682. This results in a net GPIF reward of $889,840.

Regarding ANOHR, five of the eight fossil units operated with ANOHRs that were within the ±75 Btu/kWh dead band so there were no incentive rewards or penalties while the other three operated above the dead band so they received a combined penalty of $2,767,466. Thus, the total fossil units' heat rate performance results in a net GPIF penalty of $2,767,466.

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

A. The net GPIF fossil availability performance reward of $889,840 plus the net GPIF heat rate fossil performance penalty of $2,767,466 results in a total GPIF penalty for FPL's fossil units of $1,877,626.

Q. To recap, what is the total GPIF result for the period January through December 2017?

A. The total GPIF result for the period January through December 2017 is $11,716,743 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 $5,857,941.

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. 20180001-EI

AUGUST 24, 2018

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 2019.

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 Exhibit CRR-2. This Exhibit supports the development of the 2019 GPIF EAF and ANOHR targets. The first page of this 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 2019 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 2019, FPL projects a weighted system equivalent planned outage factor ("EPOF") of 7.0% and a weighted system equivalent unplanned outage factor ("EUOF") of 5.8%, which yield a weighted system EAF target of 87.2%. The targets for this period reflect planned refuelings for St. Lucie Unit 1 and Turkey Point Unit 4. FPL also projects a weighted system ANOHR target of 7,306 Btu/kWh for the period January through December 2019. 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 2019. 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 EPOF and 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 and the historical equivalent maintenance outage factor. 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, a set of curves that reflect historical ANOHR and unit net output factors are developed for each GPIF unit. The historical 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 historical 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 2019 represent the top 80.8% of the total forecasted system net generation for this period excluding the Port Everglades and Okeechobee Energy Centers. Port Everglades Energy Center came into service in 2016 and was excluded from the GPIF calculation because there is insufficient historical data to include it. Okeechobee Energy Center is not projected to come into service until the second quarter of 2019. Consistent with the GPIF Manual, these units will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2019 EAF and ANOHR performance targets as shown on Exhibit CRR-2 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

In re: Fuel and purchase power cost recovery clause with generating performance incentive factor	Docket No.: 20180001-EI Date: October 31, 2018

ERRATA SHEET

AUGUST 24, 2018 TESTIMONY OF STEPHANIE CASTANEDA

PAGE	LINE	
Page 1	Line 21	Change “Master of Accounting” to “Master of Business Administration”

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEPHANIE CASTANEDA

DOCKET NO. 20180001-EI

AUGUST 24, 2018

Q. Please state your name and business address.

A. My name is Stephanie Castaneda, 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 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.

Q. Please describe your educational background and professional experience.

A. I graduated from Florida Atlantic University in 2003 with a Bachelor of Arts in Accounting and earned a Master of Accounting degree from Florida Atlantic University in 2012. Beginning in 2002, I was employed by McGladrey & Pullen, LLP as an external auditor and joined FPL in

2007. During my tenure at FPL, I have held various accounting and regulatory positions with the majority of my career focused in regulatory accounting and internal auditing. I am a Certified Public Accountant licensed in the State of Florida.

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 requirement associated with the Solar Base Rate Adjustments ("SoBRA") related to the solar photovoltaic projects expected to be placed in service in 2019 (the "2019 Project"). In addition, I will explain the appropriate regulatory treatment for investment tax credits ("ITC") associated with the 2019 Project 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 requirement for the SoBRA is based on the first 12 months of operations of the Project. 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 requirement for the first 12 months of operations related to the 2019 Project is $51,685,454. This calculation is largely based on the estimated capital expenditures presented by FPL witness

Brannen in his direct testimony filed on March 2, 2018.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibit:

- SKC-1 – 2019 SoBRA Revenue Requirement Calculation

Q. Please briefly describe the basis for the SoBRA Project's revenue requirement.

A. Pursuant to the 2016 Settlement Agreement, FPL is authorized to recover the revenue requirement based on the first 12 months of operations of the Project. If approved, the 2019 SoBRA is expected to be implemented on March 1, 2019.

Q. Did FPL calculate its 2019 SoBRA Project in the same manner or consistent with the 2017 and 2018 SoBRA Projects?

A. Yes. The SoBRA revenue requirement is calculated using the same methodology as approved by the Commission in Order No. PSC-2018-0028-FOF-EI.

Q. What is the amount of FPL's requested SoBRA for the 2019 Project?

A. As reflected on page 1 of Exhibit SKC-1, the amount of FPL's requested base revenue increase for the first 12 months of operations of the 2019 Project is $51,685,454.

Q. Please describe inputs utilized to compute the revenue requirement for the 2019 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 the Project in his direct testimony filed on March 2, 2018.
- 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 that is 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. For the 2019 Project, FPL used the equity ratio and long-term debt rate set forth on Schedule 4, Page 1 of 2, of FPL's May 2018 Earnings Surveillance Report. FPL also incorporated an estimate for unamortized ITCs. This approach to incremental cost of capital is the same as was approved for FPL's 2017 and 2018 SoBRA Projects. The incremental cost of capital calculation for the 2019 Project is reflected on page 3 of Exhibit SKC-1.

- 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 2017 and 2018 SoBRA Projects. The ADIT for the 2019 Project primarily reflects the timing difference between book and tax depreciation over the life of the assets. In addition, FPL is required to comply with 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 calculated employing the same approach utilized to calculate the revenue requirements for FPL's 2017 and 2018 Projects. The ADIT proration adjustment for the 2019 Project is reflected on page 5 of Exhibit SKC-1.

Q. Please describe the ITCs associated with the revenue requirement calculation for the 2019 Project.

A. In accordance with Section 48 of the IRC, the Company will record an ITC of approximately $100.5 million. This represents 30% of the qualified capital spending associated with 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 Exhibit SKC-1, 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. Furthermore, it is also consistent with the 2017 and 2018 SoBRA revenue requirement calculations approved by the Commission in Order No. PSC-2018-0028-FOF-EI.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF WILLIAM F. BRANNEN

DOCKET NO. 20180001-EI

MARCH 2, 2018

Q. Please state your name and business address.

A. My name is William F. Brannen. My business address is NextEra Energy Resources, LLC ("NEER"), 700 Universe Boulevard, Juno Beach, Florida, 33408.

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

A. I am employed by NEER as a Senior Director for Project Engineering and Due Diligence.

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

A. I manage the development and implementation of engineering, technology selection, and execution strategies for universal solar and distributed generation projects for NextEra Energy, Inc., the parent of Florida Power & Light Company ("FPL") and NEER. I am responsible for coordinating the activities of project team members to optimize the value of projects by leveraging technology advances, market dynamics, and supplier relationships during the early stage due diligence, permitting, engineering, and execution phases of these projects. My goal is to ensure that development projects meet or exceed reliability and performance requirements while maintaining reasonable costs.

Q. Please describe your education and professional experience.

A. I earned both a Bachelor and Master of Science in Civil Engineering from the University of New Hampshire. Additionally, I hold a Master of Business Administration from Nova Southeastern University. I have been a licensed professional engineer in the State of Florida since 1981. I have worked for FPL and NEER since 1979. During that time, I have held a variety of technical, operational, commercial, and management positions in areas related to power generation, engineering, and construction. I have experience in a wide range of power generation technologies including nuclear, combined cycle, wind and approximately 3,360 MW of photovoltaic ("PV") and concentrated solar thermal facilities. Since 2009, I have been responsible for key aspects of the design and construction of all fourteen of FPL's universal solar energy centers. The total capacity of these centers is approximately 930 MW, which is made up of one 74.5 MW solar thermal facility and approximately 855 MW of PV generation at 13 solar energy centers. In addition to these FPL facilities, I have served the same function for 350 MW of solar thermal generation in California and Spain, as well as approximately 2,080 MW of universal solar PV generation throughout North America outside of Florida.

Q. What is the purpose of your testimony?

A. The purpose of my direct testimony is three-fold. First, I discuss FPL's experience designing, building, and operating universal solar. Second, I describe the four universal solar energy centers currently being constructed by FPL, which are expected to begin commercial operation by March 1, 2019 ("2019 Project"). I provide a description of the centers, the technology, engineering design parameters, construction, operating characteristics, and overall costs and schedules. Third, I demonstrate that the cost of the components, engineering, and construction estimated for the 2019 Project is reasonable and falls well below \$1,750 per kilowatt alternating current ("kW_{AC}"), the cost cap approved by the Commission as part of FPL's 2016 rate case settlement.

Q. Please summarize your testimony.

A. My testimony demonstrates that the estimated cost to build the 2019 Project -- \$1,386/kW_{AC} -- is reasonable and falls well below the \$1,750 per kW_{AC} cost cap. Additionally, I testify that the universal solar energy centers will deliver high levels of efficiency and reliability to serve FPL customers.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibits WFB-1 through WFB-6. The titles to each exhibit are shown below, and they are all attached to my direct testimony.

Exhibit WFB-1	List of FPL Universal PV Solar Energy Centers in Service
Exhibit WFB-2	Typical Solar Energy Center Block Diagram
Exhibit WFB-3	Renderings of 2019 Solar Energy Centers
Exhibit WFB-4	Specifications for 2019 Solar Energy Centers

Exhibit WFB-5 Property Delineations, Features and Land Use of 2019 Solar Energy Centers

Exhibit WFB-6 Construction Schedule for 2019 Solar Energy Centers

Q. Does FPL have experience in designing and building universal PV solar facilities?

A. Yes. FPL's extensive experience designing and building universal solar generation facilities places it among the leaders in the U.S. Since 2009, FPL has completed thirteen universal solar centers totaling approximately 855 MW_{AC}. The existing FPL universal solar energy centers range in size from 10 MW_{AC} to 74.5 MW_{AC}. Exhibit WFB-1 provides a list of the FPL universal solar energy centers in service.

Q. Please describe FPL's track record in building universal solar PV.

A. The thirteen universal solar energy centers FPL has constructed and placed into operation were completed an average of 28 days early, at a total cost of $1.5 billion, about 5.8% or nearly $90 million below the cumulative budget. In addition, each individual center was also completed below budget.

Q. Please describe FPL's history of operating universal solar generation.

A. FPL has been operating universal solar generation since 2009. Over that time, FPL developed and continues to improve advanced monitoring technology and performance analysis tools. These tools optimize plant operations, drive process efficiencies, and facilitate the deployment of technical skills as demand for services grows. For example, the Company's Fleet Performance and Diagnostics Center ("FPDC") in Juno Beach, Florida, provides FPL with the capability to monitor every plant in its system. The FPDC uses advanced technology to identify potential problems, often before they can be detected by traditional methods, and allows the operating teams the opportunity to prevent or mitigate the effects of failures. FPL compares the performance of like components on similar generating units and determines how to make improvements, which often avoids problems before they occur and improves service reliability for FPL customers. Live video links can be established between the FPDC and plant control centers to immediately discuss challenges that may arise, thus enabling FPL to prevent, mitigate, or solve problems.

Additionally, FPL has recently established the Renewable Operations Control Center ("ROCC"), which serves as the centralized remote operations center for all FPL PV solar and energy storage facilities. The ROCC provides a mechanism to efficiently manage daily work activities and ensure effective deployment of best operating practices at all of FPL's renewable energy centers.

The FPL team has leveraged these capabilities along with its broad range of experience to develop robust and industry-leading operating plans that deliver high levels of reliability and availability at low cost. Each of the solar energy centers that FPL has placed in operation since 2009 is meeting or exceeding performance expectations.

Q. Please identify the centers that comprise 2019 Project.

A. FPL will place four solar energy centers in service by March 1, 2019. These are the Miami-Dade Solar Energy Center in Miami-Dade County, the Interstate Solar Energy Center in St. Lucie County, the Pioneer Trail Solar Energy Center in Volusia County, and the Sunshine Gateway Solar Energy Center in Columbia County. Each center will have a nameplate capacity of 74.5 MW_{AC}. The centers are more fully described and depicted in Exhibits WFB-2, WFB-3, WFB-4 and WFB-5.

Q. Has FPL finalized the site layouts and designs for the solar centers?

A. No, not at this time. FPL used base-line designs to establish the cost and performance projections for the centers. However, FPL is continuing to evaluate potential optimization opportunities. My testimony and the analysis presented in Witness Enjamio's testimony are predicated on the base-line designs. Details of the final designs for the solar centers would differ from the base-line only if such changes result in a greater benefit to FPL's customers.

Q. Please describe the solar PV generation technology that FPL plans to use.

A. The 2019 Project will utilize approximately 1,280,000 silicon crystal solar PV panels that convert sunlight to direct current ("DC") electricity. The panels utilized at the solar energy centers have an average conversion efficiency of approximately 17.7%. This simply means that 17.7% of the solar energy reaching the surface of the panels is converted into DC electrical energy. The efficiency of the panels that will be used on the 2019 Project is among the highest for universal solar applications in the U.S. market and is even higher than the efficiency for the panels used in FPL's 2017 and 2018 solar projects.

The panels will be mounted on fixed-tilt support structures and will be linked together in groups, with each group connected to an inverter, which transforms the DC electricity produced by the PV panels into alternating current ("AC") electricity. The voltage of AC electricity coming out of each inverter is increased by a series of transformers to match the transmission interconnection voltage for each solar center site. The inverters are paired with a single medium voltage transformer on a common equipment skid to form a power conversion unit ("PCU"). Twenty-six PCUs are required to produce a capacity of 74.5 MW_{AC} at each of the four centers. The ratio of the total installed DC capacity of PV modules to the AC capacity of each energy center (the "DC/AC Ratio") is 1.52.

Q. What is the significance of the DC/AC Ratio?

A. Design optimization activities established that the 1.52 DC/AC Ratio coupled with fixed-tilt support systems and careful selection of other major components yields high levels of output, availability and reliability, and the highest overall benefit to customers. The result is lower cost and optimized generation for the solar energy centers compared to other options. Exhibit WFB-2 provides a typical block diagram depicting the basic layout of major equipment components.

Q. How will the solar energy centers be interconnected to FPL's transmission network?

A. As noted earlier, each of the four centers has an individual point of interconnection to the FPL transmission system. The overall transmission interconnection schemes to be implemented at each center are similar although the specific details vary from center to center, based on the most cost-effective options. New collection substations with step-up power transformers will be constructed for each of the centers. The step-up power transformers increase the AC voltage from 34.5 kV to the voltages at the transmission point of interconnect. The interconnection voltages for the centers range from 115 kV to 230 kV. Each of the new collection substations will be connected to the bulk transmission system at the corresponding point of interconnection by generation tie lines that vary in length from a tenth of a mile to just under a mile.

Q. Does FPL's cost estimate include the costs associated with transmission interconnection?

A. Yes. The estimated capital construction cost for each of the centers includes the cost for its unique interconnection configuration. No upgrades to the existing FPL bulk transmission system are required to accommodate the proposed solar energy centers.

Q. Are upgrades to the existing FPL bulk transmission system required to accommodate the proposed solar energy centers?

A. No. As a result, there are no costs associated with upgrading FPL's transmission system.

Q. Can you explain how FPL acquired the property and optimized the land use for each of the centers?

A. Yes. FPL identified candidate parcels available for purchase for the four centers through a review of real estate listings and public land records. FPL screened the list of candidate parcels by using criteria including the property's proximity to a transmission system interconnection point and whether the property provides sufficient acreage to accommodate the permitting requirements and the construction of the solar centers. Because the landowners sell the parcels as a whole, FPL evaluated the features of each property – such as the presence of wetlands and flood plains, environmental constraints and cultural restrictions – and developed designs that optimize the land use for each parcel. Exhibit WFB-5 depicts the features and land use associated with each parcel.

Q. What is the proposed construction schedule for the 2019 Project?

A. As noted earlier, it is expected that the Project will be placed into service by March 1, 2019. The period necessary to complete engineering, permitting, equipment procurement, contractor selection, construction, and commissioning will exceed twelve months. This construction period includes the time necessary to prepare each of the sites, construct roads and drainage systems, install solar generating equipment and fencing, and build the interconnection facilities. The construction schedules support the proposed commercial in-service dates. Exhibit WFB-6 provides more details regarding the construction schedules.

Q. As of March 2, 2018, what is the status of the certifications and permits required to begin construction for the centers?

A. The Florida Department of Environmental Protection ("FDEP") has issued the required permits for all four of the centers. Two of the four sites also require approval from the U.S. Army Corps of Engineers; one of these permits has been issued, and the remaining site is expected to receive approval well in advance of the date required to support the construction schedule. Finally, applications for the required county zoning, special exceptions, and site plan approvals have been submitted. All four sites have received all county level approvals.

Q. What is FPL's estimated cost for the 2019 Project?

A. FPL estimates the cost of the 2019 Project will be $413 million or $1,386/kW$_{AC}$. The cost of each center ranges from $1,289/kW$_{AC}$ to $1,460/kW$_{AC}$. FPL is in the final stages of securing fixed pricing for the supply of all the required equipment and materials, as well as for engineering and construction of the solar centers the interconnection facilities.

Q. Are the cost estimates for equipment, engineering, and construction for the proposed solar generation reasonable and prudent?

A. Yes.

Q. What is the basis for your conclusion?

A. The costs for 99.6% of all the surveying, engineering, equipment, materials and construction services necessary to complete the centers were established through competitive bidding processes specific to the 2019 Project. The balance was the result of leveraging existing agreements for engineering services, which themselves were the result of a separate competitive bidding process. Therefore, 100% of these costs were subject to competitive solicitations.

Q. Please describe the competitive solicitations associated with the 2019 Project.

A. In late 2017 and early 2018, FPL solicited proposals for the supply of the PV panels, PCUs and step-up power transformers as well as the engineering, procurement and construction ("EPC") services required to complete the proposed solar energy centers. The scope of services for the engineering, procurement and construction solicitations included the supply of the balance of equipment and materials.

FPL requested proposals for PV panels from fourteen large, industry-leading suppliers. Eight suppliers submitted bids that satisfied the requirements of the request for proposals. The eight conforming bids were evaluated. Due to the volume of panels required for the 2019 Project, FPL contracted with more than one supplier. FPL was able to secure panels from the lowest cost bidders. In addition to offering the lowest cost and highest efficiency, these suppliers demonstrated that they have among the highest product quality programs in the industry and were able to provide strong financial performance security.

FPL solicited proposals from seven PCU suppliers. All of the proposals met the requirements of the request for proposals and were evaluated. FPL is finalizing its evaluation of inverter supply options.

FPL solicited proposals for step-up power transformers from nine industry-leading manufacturers, one of which declined to submit a proposal. FPL evaluated the proposals and selected the lowest cost transformers.

EPC proposals for the Project were solicited from four industry-recognized contractors. All of the bids met the requirements of the request for proposals. Accordingly, all the proposals were evaluated. FPL is finalizing a contract with the EPC contractor that submitted the lowest and most competitive proposal for the construction of the 2019 Project.

Proposals for the construction of the substation and interconnection facilities were solicited from ten industry-recognized contractors. Four contractors did not submit bids. The remaining six bids satisfied the requirements of the request for proposal and were evaluated. The lowest cost bidder has been selected to construct the substation and interconnection facilities.

The bids from the PV panel, PCU, and step-up power transformer suppliers, as well as those received from the EPC contractors, were high quality and extremely competitive.

Q. Are there other benefits associated with the 2019 Project?

A. Yes, there are a number of other benefits associated with the Project. For example, approximately 200 individuals will be employed at each of the centers at the height of construction, creating about 800 jobs. The contractors building the solar energy centers are required to exercise reasonable efforts to use local labor and resources. The jobs associated with the construction of the centers will therefore provide a secondary benefit by boosting the economy of local businesses. Additionally, the local communities will benefit from increased property tax revenues following the completion of the solar centers.

Q. How does the cost of the 2019 Project compare to the cost of FPL's 2017 and 2018 Projects?

A. The estimated cost for FPL's 2017 Project was \$1,405/kW_{AC} and the estimated cost for the 2018 Project was \$1,485/kW_{AC}. At \$1,386/ kW_{AC}, the estimated cost of the 2019 Project is lower than the estimated cost for both the 2017 and 2018 Projects.

Q. Are FPL's projected costs and construction schedules reasonable and below the cost cap of $1,750/kW_{AC}$?

A. Yes. The estimated cost for the 2019 Project is well below the prescribed cost cap, and the competitive bidding process provides assurance that costs for equipment, engineering, and construction for the 2019 Project are reasonable as previously discussed. The construction schedule for the Project also is reasonable.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF JUAN E. ENJAMIO

DOCKET NO. 20180001-EI

MARCH 2, 2018

Q. Please state your name and business address.

A. My name is Juan E. Enjamio. 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 Manager of Analytics in the Finance Department.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Florida in 1979 with a Bachelor of Science degree in Electrical Engineering. I joined FPL in 1980 as a Distribution Engineer. Since my initial assignment in FPL, I have held positions as a Transmission System Planner, Power System Control Center Engineer, Bulk Power Markets Engineer, Supervisor of Transmission Planning, and Supervisor of Supply and Demand Analysis. In 2004, I became Supervisor of Integrated Analysis – Resource Planning. In 2014, I became Manager of Analytics – Finance Department.

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

A. In my current position as Manager of Analytics, I am responsible for the management and coordination of economic analyses of alternatives to meet FPL's resource needs and maintain system reliability.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring the following exhibits which are attached to my direct testimony:

- JE-1 Load Forecast
- JE-2 FPL Fuel Price Forecast
- JE-3 FPL Resource Plans
- JE-4 CPVRR – Costs and (Benefits)
- JE-5 Avoided Fossil Fuel
- JE-6 Avoided Air Emissions

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

A. The purpose of my testimony is to present the results of the economic analysis, which shows that 298 megawatts alternating current ("MW_{AC}") of universal solar photovoltaic ("PV") generation scheduled to be placed in service in early 2019 is cost-effective. My testimony covers several areas. First, I identify the four sites on which the solar PV facilities will be constructed. Second, I discuss the major assumptions and the methodology used to perform the economic analysis. Third, I present the results of the economic analysis demonstrating that the addition of 298 MW_{AC} of solar PV generation is cost-effective. Lastly, I discuss non-economic benefits derived from the construction and operation of these facilities.

Q. Please summarize your testimony.

A. FPL is proposing the construction and operation of 298 MW_{AC} of solar PV generation, consisting of one construction project made up of four universal solar energy centers which are expected to be in-service by March 1, 2019 (the "2019 Project"). FPL performed an economic analysis and determined that the 2019 Project will result in a reduction in the cumulative present value of revenue requirements ("CPVRR") to FPL customers, for a total savings of approximately $40 million. In addition, these centers are projected to result in a significant reduction in air emissions, primarily carbon dioxide ("CO_2") resulting from a reduction in the projected use of fossil fuels, which will in turn lower FPL's system reliance on generation fueled by natural gas. The 2019 Project is cost-effective, as required to qualify for a Solar Base Rate Adjustment ("SoBRA") under FPL's 2016 Rate Case Settlement approved by the Commission in Order No. PSC-16-0560-AS-EI.

Q. Please describe the 2019 Project.

A. The 2019 Project comprises four centers with a total nameplate capacity of 298 MW_{AC}, which will be constructed and placed in service by March 1, 2019. Each of these centers can generate about 173,000 MWh in a year. This is enough energy to serve the annual energy needs of about 14,500 homes. FPL witness Brannen describes each center in greater detail and demonstrates that the cost for the proposed solar generation is reasonable, and falls well below the $1,750 per kilowatt alternating current ("kW_{AC}") threshold established in the 2016 Rate Case Settlement.

Q. What are the major system assumptions used in this study?

A. The major assumptions used in this study are the following:

- **Load Forecast –** The analysis uses FPL's most recent long-term load forecast, approved as FPL's official load forecast in February 2018. This load forecast, including system peaks and net energy for load, will be used in FPL's 2018 Ten Year Site Plan ("TYSP") and is shown in Exhibit JE-1;
- **Fuel Price Forecast –** The analysis uses FPL's most recent long-term fuel forecast, based on FPL's standard long-term fuel forecasting methodology, approved as FPL's official fuel price forecast in February 2018. This fuel price forecast will be used in FPL's 2018 TYSP and is shown in Exhibit JE-2;
- **CO_2 Emission Price Forecast -** The CO_2 cost projections used in this filing are based on ICF's proprietary CO_2 compliance costs forecast dated January 31, 2018. ICF is a consulting firm with extensive experience in forecasting the cost of air emissions and is recognized as one of the industry leaders in this field. This forecast, which assumes that CO_2 compliance costs will start in the year 2028, will be used in preparing FPL's 2018 TYSP.

Q. Please describe the resource plans that formed the basis for FPL's cost-effectiveness analysis.

A. For purposes of this filing, FPL developed two resource plans. The first resource plan, called the "No Solar Plan," does not include any new solar facilities beyond those already in-service as of March 1, 2018. In this plan, future resource needs are met by combined cycle units and short-term power purchases and by the planned extension of the operating lives of the Turkey Point 3&4 nuclear units by 20 years (from 2032 to 2052 for Unit 3 and from 2033 to 2053 for Unit 4).

The second resource plan, called the "2019 Solar Plan," adds the 2019 Project described above. Since each center is assumed to provide FPL approximately 55% of the nameplate capacity as firm capacity to meet the Company's reliability obligations, the size of several short-term purchase power agreements needed between 2019 and 2030 were reduced, a greenfield combined cycle unit that would have been placed in service in 2028 was delayed to 2029, and the size of the combined cycle unit projected for 2031 was also reduced to account for the solar firm capacity at the time of summer peak. These two resource plans are shown in Exhibit JE-3.

Q. How did FPL determine the firm capacity that solar facilities will provide?

A. Firm capacity value is based on the expected output of a solar facility at the time of summer peak load, which typically occurs annually in August from 4 p.m. to 5 p.m., and winter peak load, which typically occurs in January from 7 a.m. to 8 a.m. FPL applies this same methodology to all its solar PV facilities, existing or new.

The 2019 centers are projected to have a first-year net capacity factor of 26.5% and a summer firm capacity value of 55% of their nameplate rating. Therefore, each of the four centers with a nameplate capacity of 74.5 MW_{AC} is assumed to have a firm capacity value of 41 MW_{AC} for a total firm capacity of 164 MW_{AC} at time of summer peak. These solar installations are assumed to have zero firm capacity value at time of winter peak due to FPL's winter peak occurring in the early morning, when there is little or no solar generation output.

Q. Please provide an overview of the analytical process that FPL used to determine the cost-effectiveness of the 2019 Project.

A. FPL used the hourly production costing model UPLAN to forecast the system economics and compare resource plans that include or exclude the 2019 Project. This model has been used by FPL in prior proceedings at the Commission. Each UPLAN modeling run is used to determine generation system costs, consisting primarily of fuel costs, variable O&M costs, and emissions costs for a given resource plan. The output of each of the UPLAN model runs is then imported into FPL's Fixed Cost Spreadsheet ("FCSS") Model, which adds fixed costs such as capital costs, capital replacements costs, and fixed O&M costs. The FCSS Model is used to determine the CPVRR for each resource plan.

Q. Please provide the result of the economic analysis.

A. To determine the CPVRR impact of the proposed solar generation, FPL subtracted the CPVRR of the No Solar Plan from the CPVRR of the 2019 Solar Plan. As shown in Exhibit JE-4, the CPVRR benefit to FPL customers from the 2019 Project is approximately $40 million.

Q. Will the 2019 Project reduce FPL's use of fossil fuel?

A. Yes. As shown on Exhibit JE-5, the energy from the 2019 Project will displace fossil fuel generation. The Project is expected to reduce the annual average use of natural gas by 4,463 million cubic feet, the use of oil by 6,224 barrels, and the use of coal by 1,838 tons. By adding the Project to its generation fleet, FPL reduces its reliance on natural gas, coal and oil.

Q. What effect will these solar energy centers have with respect to greenhouse gases and other air emissions?

A. As shown in Exhibit JE-6, reducing the use of fossil fuel results in an average annual reduction of 271,000 tons of global warming gases, specifically CO_2. This reduction in CO_2 is equivalent to removing approximately 52,000 cars from the road. Sulfur dioxide and nitrogen oxide emissions are reduced by an annual average of 14 tons and 45 tons, respectively.

Q. What is your conclusion regarding the 2019 Project?

A. As demonstrated by the economic analysis described in my testimony, the addition of the 2019 Project will result in CPVRR savings of approximately $40 million. Therefore, the 2019 Project meets the SoBRA cost-effectiveness requirement established in the 2016 FPL Rate Case Settlement. Additionally, the Project will reduce the use of fossil fuel, reduce air emissions, and reduce FPL's reliance on natural gas.

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. 20180001-EI

AUGUST 24, 2018

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 Director, Rates & Tariffs.

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

A. I am responsible for developing the appropriate rate design and for administration of the Company's electric rates and charges. Additionally, I am responsible for the Company's cost of service and load research studies.

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. Since joining FPL in 2008, I have held positions of increasing responsibility within the Company's Regulatory Affairs Organization, including Manager of Rate Development, and was promoted to my current role in December 2017. 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 as the Finance Director, 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 March 1, 2019 ("2019 Project").

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 2019 SoBRA Factor Calculation;
- TCC-2 Projected Retail Base Revenues;
- TCC-3 Summary of Tariff Changes for March 1, 2019; and
- TCC-4 Typical Bill Projections.

Q. Please explain the calculation of the SoBRA factor and the purpose it serves.

A. I have calculated the SoBRA factor 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 factor is equal to the ratio of (1) the Company's jurisdictional revenue requirements for the Project and (2) the forecasted retail base revenue from electricity sales for the first twelve months of operations, expected to begin March 1, 2019. Application of the SoBRA factor to the Company's March 1, 2019 base rates will provide the Company with sufficient revenue to recover the costs associated with the construction and operation of the 2019 Project. The calculation and resulting SoBRA factor of 0.795% is shown in Exhibit TCC-1, page 1 of 1.

Q. Do you have an exhibit that provides the forecasted retail base revenue for the projected 12-month period beginning March 1, 2019?

A. Yes. Exhibit TCC-2, page 1 of 1, provides the forecasted retail base revenue from the sales of electricity for all customer classes for the projected 12-month period beginning March 1, 2019. 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 and Commercial/Industrial Demand Reduction Rider credits, and non-clause recoverable credits (*e.g.*, transformation rider credits and curtailable service credits). Thus, all the charges subject to the SoBRA factor 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 March 1, 2019 are projected to be $6,501.950 million, shown on Exhibit TCC-2, page 1 of 1.

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 March 1, 2019?

A. Yes. Exhibit TCC-3 provides a summary of the base rates proposed to become effective for meter readings made on and after March 1, 2019, shown in column 4 of Exhibit TCC-3, pages 1-25. If the SoBRA and the associated charges are approved for the 2019 Project, the Company will submit revised tariff sheets reflecting the Commission-approved charges.

Q. Please explain how the Company will notify the Commission of the 2019 Project's commercial operation date?

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

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

A. Exhibit TCC-4 provides projected bill changes. The typical bill projections reflect proposed clause changes to become effective on January 1, 2019 and proposed base and fuel changes related to the 2019 Project SoBRA scheduled to become effective March 1, 2019.

FPL projects that the March 2019 typical residential bill of $100.73 will remain 27% below the national average (as of January 2018), 13% below the state average (as of June 2018), and will remain among the lowest in the state of Florida.

Q. **Will customers receive a credit if the actual capital expenditures for the 2019 Project 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 in revenue requirements resulting from 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. 20180001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2017 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 2017 through December 2017.

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 2017 through December 2017?

A. For the Consolidated Electric Division the final remaining true-up amount is an under recovery of $2,245,979.

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 2017 period and the total true-up amount to be collected or refunded during the January - December 2018 period.

Q. What was the actual end of period true-up amount for January - December 2017?

A. For the Consolidated Electric Division it was $5,637,395 under recovery.

Q. What was the Commission-approved amount to be collected or refunded during the January – December 2018 period?

A. A consolidated under-recovery of $3,391,416 to be collected.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20180001-EI: Fuel and purchased power cost recovery clause

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

On Behalf of

Florida Public Utilities Company

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. Yes, I have.

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 2019 – December 2019.

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 including Schedules E1-A, E1-B, and E1-B1 as part of 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 2018 – December 2018 based on 6 Months Actual and 6 Months Estimated data.

Q. What was the final remaining true-up amount for the period January 2017 – December 2017?

A. The final remaining true-up amount was an under-recovery of $2,245,979.

Q. What is the estimated true-up amount for the period January 2018 – December 2018?

A. The estimated true-up amount is an under-recovery of $3,176,245.

Q. What is the total true-up amount to be collected, or refunded during January 2019 – December 2019?

A. At the end of December 2018, based on six months actual and six months estimated, the Company estimates it will under-recover $5,422,224 in purchased power costs, which will be collected from January 2019 – December 2019.

Q. Has the Company made any revisions to its 6-month estimated 2018 data on its submitted Schedules from previously filed projections for this same period?

A. Yes, we have made revisions to our monthly estimates of our KWH sales data based on information available from our most current budget forecasts. Also, our estimated purchases and fuel costs have updated in accordance with the current billing data.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2019 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 2019 - December 2019 purchased power 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 purchased power adjustment for the period January 2018 – December 2018 and to establish a "true-up" amount to be collected or refunded during January 2019 - December 2019.

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 and purchased power 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 and purchased power 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 fuel related costs included in the fuel clause are directly related to purchased power, 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. Similar expenses paid to Christensen and Associates associated with the design for a Request for Proposals of purchased power costs, and the evaluation of those responses, were deemed appropriate for recovery by FPUC through the fuel and purchased power clause in Order No. PSC-05-1252-FOF-EI, Item II E, issued in Docket No. 050001-EI. Additionally, in more recent Docket Nos. 20140001-EI, 20150001-EI, 20160001-EI, 20170001-EI and 20180001-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 purchased power 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 power costs included in the 2018 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"), Pierpont and McClelland ("Pierpont") and Black and Veatch Corporation ("B & V") for assistance in the development and enactment of projects/programs designed to reduce their purchased power rates to its customers. The associated legal and consulting costs, included in the rate calculation of the Company's 2019 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 purchased power 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.

B & V designed a 20-year load forecast study for the Northwest Florida Division. They performed a similar load study for our Northeast Florida Division a couple of years ago. This forecast is being used to provide information to our wholesale power supplier to assist with future generation and transmission studies related to our system. Also, the current transmission agreements currently in place with Southern Company require that we provide a long range load forecast each year. 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 purchased power related savings options including other CHP opportunities and solar/photovoltaic opportunities.

Summary Rates

Q. What are the final remaining true-up amounts for the period January – December 2017 for both Divisions?

A. The final remaining consolidated true-up amount was an under-recovery of $2,245,979.

Q. What are the estimated true-up amounts for the period of January – December 2018?

A. There is an estimated consolidated under-recovery of $3,176,245.

Q. Please address the calculation of the total true-up amount to be collected or refunded during the January - December 2019 year?

A. The Company has determined that at the end of December 2018, based on six months actual and six months estimated, we will have a consolidated electric under-recovery of $5,422,224.

Q. Does the Company have an explanation for this under-recovery?

A. As of December 2017, the Company's Fuel and Purchased Power Costs were significantly under-recovered as a result of higher than anticipated under-recovery for 2017 than was estimated in our 2018 Projection filing as well as the early part of 2018. There were several factors that have changed since our original projection filing for 2018. First, the Company's contract for purchased power, in its Northeast Division, changed effective January 2018 from JEA to FPL. In preparation for this contract change, the Company attempted to estimate purchased power costs under its new arrangement with FPL, which includes more stratified billing components than prior providers. The Company's lack of experience and familiarity with these components resulted in miscalculation of the original projection. Second, the estimate received by the Company for purchased power costs for the Company's Northwest Division was somewhat lower than FPUC's ultimate bill. Third, the Company's industrial customers began a concerted effort to more efficiently manage their demand, so FPUC's estimate for that component was lower than what was experienced.

Q. As a result of the Supreme Court ruling in the case of Citizens v. Graham, has FPUC properly refunded \$221,415 to customers through the Fuel Clause in accordance with Order No. PSC-2018-0028-FOF-EI?

A. Yes, the \$221,415 was computed in Schedule E1-B from Exhibit MC-1 of the Company's Calculation of True-Up and Interest Provision for the period January 2017 - December 2017 based on 6 Months Actual and 6 Months Estimated data. The amount was subsequently refunded back to the customers through the Company's 2018 Purchased Power Recovery Factors.

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 6.433¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2019 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 $139.95. This is an increase of $6.09 over the previous period.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2019 Supplemental Direct Testimony of Michael Cassel

On Behalf of

<u>Florida Public Utilities Company</u>

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. 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 supplemental testimony at this time?

A. The purpose of my supplemental direct testimony is to support my attached, supplemental Alternate Exhibits MC-1 and MC-2, which reflect a proposed adjustment to the Company's Fuel factors for 2019 that is consistent with a settlement agreement filed by the Company and the Office of Public Counsel in Docket No. 20180048-EI ('Tax Settlement"). The adjustment reflects the flow-through of the tax savings that have inured to the Company in 2018 as a result of the federal Tax Cuts and Jobs Act of 2017. The stipulated amount of $1,464,452 is flowed-through to reduce the corresponding Fuel factor for each of the rate classes consistent with the Tax Settlement and the Commission's fuel methodology.

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. Please describe the Tax Settlement.

A. The Commission had opened Docket No. 20180048-EI for the purpose of addressing the impact of the Tax Cuts and Jobs Act of 2017 ("TCJA") on FPUC. The Office of Public Counsel ("OPC") subsequently intervened. Thereafter, in accordance with the Order Establishing Procedure for that docket, FPUC filed its Petition for Approval of Tax Benefits Adjustment Amounts and Flow-Through Mechanism on May 23, 2018, along with the testimony and exhibits of witnesses Cassel, Dewey and Reno. Over the course of the docket, we continued to engage in good-faith discussions with the OPC, which ultimately resulted in settlement that resolves the issues in that docket.

Several provisions in the Tax Settlement impact the Company's Fuel factors for 2019 in that they contemplate flowing through certain tax benefits as a downward adjustment to our Fuel factors.

Specifically, the following provisions impact the Company's Fuel factors:

<u>Article II (a)(i):</u>

For calendar year 2018, the NOI annual tax savings impact of $638,158 will be applied to the Company's existing fuel and purchased power cost recovery balance, which will serve to reduce FPUC's Fuel Cost Recovery factors for 2019.

Article II (b)(i):

For calendar year 2018, the "protected" EADIT amount of $288,230 will be applied to the Company's existing fuel and purchased power cost recovery balance, which will serve to reduce FPUC's Fuel Cost Recovery factors in 2019.

Article II (c):

The Parties agree that the grossed-up, "unprotected" EADIT balance for the Company is approximately $538,064 and that this amount shall be applied to reduce the Company's existing fuel and purchased power cost recovery balance, which will serve to reduce FPUC's Fuel Cost Recovery factors in 2019.

Q. What is the total amount of the tax benefit that will be passed through the Fuel Clause to customers if the Tax Settlement is approved?

A. The total amount is $1,464,452, the impact of which on the Fuel factors for each rate class is reflected in my Alternate Exhibit MC-2.

Q. Is the Company seeking any additional relief in this proceeding as it relates to the terms of the Tax Settlement?

A. Yes. If the Commission approves the Tax Settlement in Docket No. 20180048-EI, the Company asks that the Commission allow the

Company to apply the adjusted Fuel Factors included in my Alternate Exhibit MC-2.

Q. Does this conclude your Supplemental Testimony?

A. Yes. It does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2019 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 before the Florida Public Service Commission ("Commission")?

A. Yes, I've provided testimony in a variety of Commission proceedings, including the Company's 2014 rate case, addressed in Docket No. 20140025-EI. Most recently, I provided written, pre-filed testimony in Docket No. 20170001-EI, the Commission's regular fuel cost recovery proceeding, and also provided both pre-filed and live testimony the prior year, in Docket No. 20160001-EI, the Commissions' regular fuel cost recovery.

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 the potential for reduced purchase power costs, construction of a transmission line interconnection with FPL, execution of the new purchased power agreement with Florida Power & Light ("FPL"), generation supply located on Amelia Island and investigation into the deployment of solar and battery storage assets.

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

A. The Company regularly pursues opportunities to achieve reduced purchased power costs for the benefit of our customers. The most recent significant opportunity came to fruition with the completion of the construction of a 138

KV transmission line interconnection with Florida Power & Light (FPL) and the new purchased power agreement with FPL that became effective January 1, 2018.

Q. When was construction of the FPL transmission interconnection completed?

A. As mentioned above, the transmission interconnection between FPL and FPUC was in-service on January 1, 2018. However, the total project, which included significant modifications to the transmission systems of FPL, JEA and FPUC, was not completed until the third quarter of 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. 20170001-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 project had on our overall rate.

Q. What is the status of the existing purchase power agreements in place with Gulf Power and FPL?

A. The existing agreement with Gulf is effective through December 31, 2019. FPU has begun investigation of the possible wholesale power solutions for the Northwest Florida Division (Marianna), which is currently served by Gulf Power Company. Information regarding the generation and transmission aspects of the agreement have been collected in order to make a determination of the most prudent energy supply. The agreement will be in place prior to the December 31, 2019 expiration date of the current agreement.

The existing agreement with FPL will continue in place until the December 31, 2024 expiration date.

Q. Can you provide background on the new purchased power agreement with FPL that became 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. 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 discussions with potential new project partners. These projects are still in the early 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 identified and analyzed that the development of specific, smaller PV systems within the FPUC electric service territory. However, due to many variables, the economic feasibility has been difficult to achieve due to many different factors. Based on this analysis, FPUC is investigating opportunities involving larger PV installations which should prove to be more economically feasible. 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.

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

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

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

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

DATED this 7th day of November, 2018.

Debbie R Krick

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