BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20190001-EI

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE WITH
GENERATING PERFORMANCE
INCENTIVE FACTOR.
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VOLUME 1
PAGES 1 through 416

PROCEEDINGS: HEARING

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

DATE: Tuesday, November 5, 2019

TIME: Commenced: 4:15 P.M.
Concluded: 4:37 P.M.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

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APPEARANCES:

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RUSSELL A. BADDERS, ASSOCIATE GENERAL COUNSEL, One Energy Place, Pensacola, Florida 32520-0100; and STEVEN R. GRIFFIN, ESQUIRE, Beggs & Lane, P.O. Box 12950, Pensacola, Florida 32591-2950, appearing on behalf of Gulf Power Company.

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

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

SUZANNE BROWNLESS, 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; LEE ENG TAN, ESQUIRE, 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

WITNESSES CONTINUED

EXHIBITS

NUMBER:		ID	ADMITTED
1	Comprehensive Exhibit List	399	400
83-99	As identified in the comprehensive exhibit list	399	400
2-7, 9-67, 77-79	As identified in the comprehensive exhibit list		413 413 413
8, 80-82, 100	As identified in the comprehensive exhibit list	400 400	
68-76	As identified in the comprehensive exhibit list	400	

P R O C E E D I N G S

CHAIRMAN GRAHAM: 01 docket. Staff, preliminary matters.

Mic. All right, it's on.

MS. BROWNLESS: It's on. Okay, I will start over.

Opening statements, if any, are limited to five minutes per party. Issues 1B and 1C address the April 2017 outage at DEF's Bartow Unit 4 and have been referred by Chairman Graham to the Division of Administrative Hearings for a hearing at a later date.

Bartow replacement costs have been included in dollar amounts for Issues 8, 10, 18, 20 and 22. These dollar amounts will be trued up and appropriate adjustments made in the 2020 fuel docket consistent with the Commission's decision on those issues.

Issue 2H, the cost-effectiveness of FPL's 2020 SoBRA projects has been contested by FIPUG and will have to be voted on. Issue 2H was incorrectly listed as a proposed stipulation in the prehearing order at page 32, and I apologize for that.

There is also now a Type 2 stipulation for Issue No. 37, the close the docket issue listed in the prehearing order on page 19.

Issue 22, the fuel cost recovery factors for each rate class delivery voltage level class, adjusted for line losses. The stipulated position for DEF stated on page 45 of the prehearing order is incorrect. DEF has provided the correct stipulation which has been provided to all parties and to all Commissioners and will be reflected in the final order if approved today.

All other issues are Type 2 stipulations and can be voted upon today.

CHAIRMAN GRAHAM: All right. Staff, let's address the prefiled testimony.

MS. BROWNLESS: It is our understanding that the following witnesses have been excused and the prefiled testimony of Menendez, Garcia, McClay, Daniel, Deaton, Yupp, Coffey, Rote, Fuentes, Brannen, Enjamio, Anderson, Young, Napier, Cutshaw -- Cutshaw, Boyett, Nicholson, Rusk, Buckley, Caldwell, Cain, Smith, Heisey, Terkawi, Ojada and Dobiac have been stipulated to by the parties. We would ask that the prefiled testimony of these witnesses be moved into the record at this time.

CHAIRMAN GRAHAM: If there is no objections,

we will move the prefiled testimony of all those
witnesses into the record.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2018 - December 2018

DIRECT TESTIMONY OF
Christopher A. Menendez

March 1, 2019

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 2018 through December 2018, 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 2018, year-to-date; and Exhibit No. __(CAM-4T), with DEF's capital structure and cost rates. Schedules A1 through A9, and A12 for the year ended December 31, 2018, were filed with the Commission on January 29, 2019.

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-2018-0610-FOF-EI, the estimated 2018 fuel adjustment true-up amount was an under-recovery of $148.5 million. The actual under-recovery for 2018 was $202.9 million resulting in a final fuel adjustment true-up under-recovery amount of $54.4 million. Exhibit No. __(CAM-1T).

The estimated 2018 capacity cost recovery true-up amount was an over-recovery of $16.6 million. The actual amount for 2018 was an over-recovery of $15.8 million resulting in a final capacity true-up under-recovery amount of $0.8 million. Exhibit No. __(CAM-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2018 for fuel cost recovery?

A. The actual ending balance as of December 31, 2018 for true-up purposes is an under-recovery of $202,879,590.

Q. How does this amount compare to DEF's estimated 2018 ending balance included in the Company's Actual/Estimated Filing?

A. The actual true-up amount attributable to the January 2018 - December 2018 period is an under-recovery of $202,879,590 which is $54,428,676 higher than the re-projected year end under-recovery balance of $148,450,915.

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 $54,428,676 shown on your Exhibit No. __(CAM-1T)?

A. The $54.4 million is driven in part by a shift from coal to gas generation resulting in increased gas generation and purchased power costs of approximately $97.6 million partially offset by reduced coal generation expense of $44.7 million.

Q. Please explain the components shown on Exhibit No. __(CAM-1T), sheet 6 of 6, which helps to explain the $52.6 million unfavorable 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 $52.6 million unfavorable system variance is mainly attributable to increased natural gas generation and purchased power, in part from a shift from coal to gas, partially offset by reduced coal generation.

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.

Consistent with Order No. PSC-2018-0240-PAA-EQ dated June 8, 2018, DEF included an adjustment of $7,276,033 (grossed up to $7,326,228 from retail to system) for amortization of the Florida Power Development, LLC (“FPD”) qualifying facility regulatory asset. This adjustment is shown on

Exhibit No. ___(CAM-3T), in the footnotes to Line 6b on page 1 of 2, Schedule A2, and on line 3, page 1 of 2, Schedule A1. An estimated adjustment of $6,232,811 (grossed up to $6,266,531 from retail to system) for FPD regulatory asset amortization was included on Schedule E1-B (sheet 2), line A5, columns Aug Estimated through Dec Estimated in the 2018 Actual/Estimated Filing on July 27, 2018.

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

A. Yes. DEF included an adjustment of approximately $5.4 million to coal inventory attributable to the semi-annual aerial surveys conducted on June 5, 2018 and November 16, 2018 in accordance with Docket No. 19970001-EI, Order No. PSC-1997-0359-FOF-EI. This adjustment represents 1.96% of the total coal consumed at the Crystal River facility in 2018.

Q. Did DEF exceed the economy sales threshold in 2018?

A. Yes. DEF did exceed the gain on economy sales threshold of $1.8 million in 2018. As reported on Schedule A1-2, Line 11a, the gain for the year-to-date period through December 2018 was approximately $2.3 million. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gain in excess of the three-year rolling average. For 2018, that amount is approximately $0.09 million.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November 2018 hearings been updated to incorporate actual data for all of year 2018?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2016 through 2018, as follows:

Year	Actual Gain
2016	$ 843,842
2017	$ 887,370
2018	$2,269,916
Three-Year Average	$1,333,709

Q. Can you explain DEF's methodology for calculating the Time-of-Use ("TOU") fuel factors?

A. Yes. Commission Order 9661, issued on November 26, 1980, established the current Winter and Summer seasons and applicable on- and off-peak times for each. Within the on- and off-peak periods defined in Order 9661, DEF's uses marginal cost to develop TOU on- and off-peak fuel multipliers ("TOU fuel multipliers"); these are presented each year in Schedule E1-E in DEF's Fuel Projection Filing. The TOU fuel multipliers are then applied to the levelized fuel rate, at secondary metering, to calculate the on- and off-peak fuel factors ("TOU fuel factors"). In Order No. PSC-2011-0216-PAA-EI, the

Commission directed Florida Power & Light ("FPL") to investigate the use of marginal cost in the calculation of the TOU fuel factors; at that time, FPL calculated the TOU fuel factors using projected on- and off-peak average cost. The Commission stated in Order No. PSC-2011-0216-PAA-EI that "[u]sing marginal fuel costs to set TOU fuel factors…increases the on- and off-peak differential, sending a stronger price signal." In Order No. PSC-2011-0579-FOF-EI, the Commission approved FPL's switch from average to marginal cost for the 2012 projected TOU Fuel Factors. DEF follows the Commission's guidance by utilizing marginal cost in to develop the TOU fuel multipliers. Additionally, the Commission has approved DEF's TOU fuel factors each year in the Fuel docket.

Q. Did DEF evaluate the need for adjustments to the on- and off-peak TOU fuel cost factors, as described in the Stipulation to Issue 22 in Order No. PSC-2018-0610-FOF-EI?

A. Yes. DEF evaluated alternative methods of calculating the TOU fuel factors. The first method is the approved marginal cost calculation, as described above. The second was the use of average cost, rather than marginal cost, in the development of the TOU Multipliers. The third method was the implementation of an artificial c/kWh spread between the TOU fuel factors.

Q. Can you please explain the results of the evaluations?

A. Yes. The evaluation of these three methods utilized the same fuel forecast used to develop DEF's 2019 Fuel Projection Filing and 2019 fuel factors. This allows for an apples-to-apples comparison between the various methods.

The first method used marginal cost to develop the TOU multipliers. This is the current method used by DEF.

The Average Cost method utilizes the average on- and off-peak costs to develop the TOU multipliers. This method almost eliminates entirely the spread between the TOU multipliers, resulting in TOU fuel factors that are essentially the same as the levelized rate.

The third method involved the development of an artificial c/kWh spread between the TOU fuel factors. The calculation method is based on the Residential 1st Tier calculation and was developed in a revenue-neutral manner when compared to the current marginal cost TOU process. This method first determines the projected on- and off-peak MWh sales for the non-Residential classes with optional TOU factors (GS-1, GSD, CS, IS and SS). This was done by separating the projected 2019 MWh sales for these rate classes into on- and off-peak based on the most recent full year actual performance. The projected 2019 TOU revenues were determined by multiplying the projected on- and off-peak 2019 MWh sales by the 2019 TOU fuel factors developed under the current marginal cost process. An artificial c/kWh spread is then calculated by applying the Residential 1st Tier formula, whereas the lower first tier becomes the off-peak fuel factor and the higher second tier becomes the on-peak fuel factor. Under this method, the amount of the c/kWh spread would need to be defined and approved by the Commission. A change in the TOU fuel factor calculation, using the artificial c/kWh spread method, will impact the fuel component of customer bills differently. Some customers will experience an increase in the fuel component of their bill, while others will see a reduction as compared to the current marginal cost method. The number of increases versus reductions to customer bills may be asymmetrical under an artificial spread scenario, for example more total customers could experience an increase than those experiencing a reduction.

Q. Based on DEF's evaluation, is DEF recommending an adjustment to the current calculation of the on- and off-peak fuel factors?

A. DEF does not believe any adjustments to the current calculation are necessary. DEF follows Commission guidance by utilizing marginal cost in the TOU fuel factor process. Despite the spread between the on- and off-peak TOU fuel multipliers narrowing in recent years, DEF believes that marginal cost still sends an accurate price signal to customers and aligns the TOU fuel cost incurred with the TOU MWhs causing that cost.

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2018 for capacity cost recovery?

A. The actual ending balance as of December 31, 2018 for true-up purposes is an over-recovery of $15,765,080.

Q. How does this amount compare to the estimated 2018 ending balance included in the Company's Actual/estimated Filing?

A. When the estimated 2018 over-recovery of $16,610,473 is compared to the $15,765,080 actual over-recovery, the final capacity true-up for the twelve-month period ended December 2018 is an under-recovery of $845,393.

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 under-recovery of $0.8 million?

A. Exhibit No. __(CAM-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $0.8 million under-recovery is primarily due to higher than estimated costs.

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

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190001-EI

Fuel and Capacity Cost Recovery
Actual/Estimated True-Up Amounts
January through December 2019

DIRECT TESTIMONY OF
Christopher A. Menendez

July 26, 2019

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. 20190001-EI?

A. Yes. I provided direct testimony on March 1, 2019.

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 2019.

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 2019 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 2019 actual/estimated capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2019 and estimated data from July through December 2019.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2019 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is an under-recovery of $14,462,684. The calculation begins with the actual under-recovered balance of $179,798,727 taken from Schedule A2, page 2 of 2, line 13, for the month of June 2019. This balance plus the estimated July through

December 2019 monthly true-up calculations comprise the estimated $14,462,684 under-recovered balance at year-end. The projected December 2019 true-up balance includes interest which is estimated from July through December 2019 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.196% per month.

Q. How does the current forecast of fuel costs on Schedule E3 for July through December 2019 compare with the same period forecast used in the Company's 2019 projection filing approved in Order No. PSC-2018-0610-FOF-EI?

A. Natural gas decreased $0.56/mmbtu (-13%), and coal and light oil costs increased $1.07/mmbtu (35%) and $1.41/mmbtu (5%), respectively.

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

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ dated June 8, 2018, DEF included an adjustment of $14,163,411 (grossed up to $14,249,283 from retail to system) for the amortization of Florida Power Development, LLC qualifying facility regulatory asset from January 2019 through December 2019. This adjustment is included on Schedule E1-B, line A5, columns Jan Actual through Dec Estimated.

Q. Does DEF expect to exceed the three-year rolling average gain on non-separated power sales in 2019?

A. Yes. DEF estimates the total gain on non-separated sales during 2019 will be $1,656,431, which exceeds the three-year rolling average of $1,333,710. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gains in excess of the three-year rolling average. For 2019, this is estimated to be $64,544.

CAPACITY COST RECOVERY

Q. What is DEF's 2019 estimated capacity true-up balance and how was it developed?

A. DEF's estimated capacity true-up balance is an over-recovery of $1,848,509. The estimated true-up calculation begins with the actual under-recovered balance of $5,888,777 for the month of June 2019. This balance plus the estimated July through December 2019 monthly true-up calculations comprise the estimated $1,848,509 over-recovered balance at year-end. The projected December 2019 true-up balance includes interest which is estimated from July through December 2019 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.196% per month.

Q. What are the primary drivers of the estimated year-end 2019 capacity over-recovery?

A. The $1.8 million over-recovery is primarily attributable to approximately $1.4 million lower capacity costs.

Q. Has DEF included the nuclear cost recovery amounts approved in Order No. PSC-2018-0490-FOF-EI?

A. Yes. DEF has included $43,827,298 of 2019 recoverable expenses associated with the CR-3 Uprate project.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190001-EI

Fuel and Capacity Cost Recovery Factors
January through December 2020

DIRECT TESTIMONY OF
Christopher A. Menendez

September 3, 2019

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. 20190001-EI?

A. Yes, I provided direct testimony on March 1, 2019 and July 26, 2019.

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 2020.

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 3.345 ¢/kWh. This factor consists of a fuel cost for the projection period of 3.2999 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.0066 ¢/kWh, and an estimated prior period under-recovery true-up of 0.0366 ¢/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 3.067 ¢/kWh for the first 1,000 kWh and 4.067 ¢/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 1.286 On-peak and 0.872 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 2019 net true-up that DEF has included in the fuel cost recovery factor for 2020?

A. DEF has included a projected under-recovery of $14,462,684. This amount includes a projected actual/estimated over-recovery for 2019 of $39,965,991, a final 2018 true-up net under-recovery of $54,428,676 as shown in my Direct Testimony filed on March 1, 2019.

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 2020 of 3.350 ¢/kWh is a decrease of 0.624 ¢/kWh or 16% from the 2019 levelized residential fuel factor of 3.974 ¢/kWh.

Q. Please explain the decrease in the 2020 fuel factor compared with the 2019 fuel factor.

A. The primary drivers of the decrease in the 2020 fuel factor are a decrease in jurisdictional fuel and purchased power expense of approximately $109 million, decrease in the prior period true-up of approximately $134 million partially offset by an increase in the GPIF amount of approximately $5 million.

Q. Have you made any adjustments to your estimated fuel costs for the period January through December 2020?

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ dated May 8, 2018, DEF included an adjustment of approximately $13.6 million (grossed up to approximately $13.7 million from retail to system) for the amortization of Florida Power Development, LLC qualifying facility regulatory asset from January through December 2020 partially offset by an approximate $13.2 million system ($13.1 million retail) credit related to Citrus.

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 3.350 ¢/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 2020 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2019 is estimated to be $1,371,287 which is below the benchmark of $1,604,573. 100% of gains below the benchmark and 80% of gains above the benchmark will be distributed to customers based on the sharing mechanism approved by the Commission in Order No. PSC-2000-1744-PAA-EI. Therefore, since the total gain on non-separated sales was below the benchmark, none of the gains will be retained for shareholders. The benchmark was calculated based on the average of actual gains for 2017 and 2018 of $887,370 and $2,269,916, respectively, and estimated gains for 2019 of $1,656,431 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 and Reedy Creek for fixed amounts of base, intermediate, peaking, solar 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 and 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 2018 GPIF reward discussed in the March 15, 2019 direct testimony of James Bradley Daniel included in 2019 rates?

A. Yes. The GPIF reward of $2,591,697 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:

<u>Schedule E12-A – Calculation of Projected Capacity Costs – Year 2020</u>

Page 1 of Schedule E12-A includes estimated 2020 calendar year system capacity payments to Qualifying Facilities ("QF") and other power suppliers. The retail portion of the capacity payments is calculated using separation factors consistent with the 2017 Settlement.

The recovery of estimated Dry Casket Storage costs, also referred to as Independent Spent Fuel Storage Installation ("ISFSI") costs, are included on line 35 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 2020 Calculation of Projected Capacity Costs on Schedule E-12A, line 36.

Schedule E12-B – Calculation of Estimated/Actual True-Up - Year 2019

Schedule E12-B, which is also included in Exhibit __(CAM-2) to my direct testimony filed on July 26, 2019, as part of the 2019 actual/estimated true-up filing, calculates the estimated true-up capacity over-recovered balance for calendar year 2019 of $1,848,509. This balance is carried forward to Schedule E12-A, line 29 to be refunded to customers from January through December 2020.

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 costs for each rate class based on the 12CP and 1/13 annual average demand allocators and ISFSI costs from Schedule E12-D. The factors for capacity 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 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 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 in columns 11 through 13.

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 2020 projected average retail CCR factor?

A. The 2019 average retail CCR factor is 1.051 ¢/kWh, made up of capacity of 1.034 ¢/kWh and ISFSI costs of 0.017 ¢/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 1.051 ¢/kWh is 0.046 ¢/kWh, or 4%, lower than the 2018 factor of 1.097 ¢/kWh. This decrease is primarily due to the conclusion of the recovery of the CR3 Uprate at year end 2019, as approved in Order No. PSC-2018-0490-FOF-EI, and the difference in the in the prior period true-up balance.

Q. Does this conclude your testimony?

A. Yes

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

ARNOLD GARCIA

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20190001-EI

MARCH 1, 2019

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS"), a subsidiary of Duke Energy Corporation ("Duke Energy"), as Manager, Insurance. Duke Energy Florida, LLC ("DEF" or the "Company") is a wholly-owned subsidiary of Duke Energy and affiliate of DEBS.

Q. What are your responsibilities in that position?

A. I am responsible for placing insurance coverage for Duke Energy and its subsidiaries.

Q. Please describe your educational background and professional experience.

A. I earned a Master on Business Administration from Wake Forest University (Winston Salem, NC), and a Bachelors of Arts degree from Colgate University (Hamilton, NY). I also hold an Associate in Risk Management (ARM) designation. I have held similar positions to my current position for other organizations such as a utility, a diversified manufacturer and two consumer product companies (one of which was a Fortune 250 Company).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is twofold: first, I will describe the insurance protection that was in place at the Bartow Combined Cycle Power Plant ("Bartow CC") on February 9, 2017; and second, it was made apparent to DEF during the 2018 fuel clause docket that there were questions regarding whether or not DEF had, or should have had, insurance coverage covering replacement power costs, therefore I will provide an overview of the types of coverages that are, and are not, available (commercially or practically) to Duke Energy and the Company for its generating assets.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibit NO. __ (AG-1), the Bartow CC Insurance Policy in effect on February 9, 2017. This exhibit is confidential.

Q. Please provide a summary of your testimony.

A. In summary, on February 9, 2017, the Bartow CC was covered by a Policy of All Risk Property Insurance Including Machinery Breakdown ("the Policy") issued by Associated Electric & Gas Insurance Services, Ltd ("AEGIS") that did not provide coverage for replacement power costs or other business interruption costs. Moreover, an Insurance Product that provided such coverage for generating units such as the Bartow CC was not available in a commercially viable form at that time; that is, the costs to the Company and its customers of any such policy would outweigh the benefit received.

Q. Please describe the Policy.

A. The Policy provides Duke Energy protection against loss occurring from damage to its generation fleet, including the Bartow CC, except under the named exclusions and subject to the limits described therein (subject to any applicable deductible).

Q. Did the Policy include an exclusion for replacement power costs?

A. Yes, it did. Section A provides the Coverage Declarations, and section A.2. is the Extra Expense declaration. Section A.2.c.(3) provides the exclusion for replacement power costs. See Ex. No.__ (AG-1). The exclusion is also shown in section 3 "Limit of Liability" on the Declarations Page, page 3 of 5, where it provides the limitation of liability for Extra Expenses as shown in that section.

Q. Was coverage for replacement power costs available for the Bartow CC during February of 2017?

A. From a practical standpoint, the answer is no cost-effective product was available in the market. Allow me to explain, Duke Energy routinely monitors developments in the insurance market and the results of those efforts have consistently shown the coverage is unavailable in the current market at a cost point that would make economic sense. Essentially, any product that would provide this sort of coverage would require a premium that would all but negate the value of the coverage being obtained (i.e., the premiums would be set equal to a high-end expected loss, plus the insurer's administrative fee).

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

DUKE ENERGY FLORIDA

DOCKET NO. 20190001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December 2018

DIRECT TESTIMONY OF
JAMES MCCLAY

April 3, 2019

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 Director Trading. I manage the Southeast power trading, Midwest financial activities, oil procurement and natural gas group procurement, scheduling and hedging activities in the Trading and Dispatch Section of the Fuels and Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for the hourly trading, financial hedging activities, oil procurement and 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 either the Director Trading, Director of Natural Gas or 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 2018 hedging true-up data and summarize the results of DEF's hedging activity for calendar year 2018 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 2018.

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 2018 and what were the results?

A. As discussed below, DEF did not execute any hedges during 2018. Prior hedging activities resulted in a net hedge savings for 2018 of approximately $588,460.

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 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 2018.

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 2019

FPSC DOCKET NO. 20190001-EI

DIRECT TESTIMONY OF James McClay

August 9, 2019

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 Director Trading. I manage the Southeast power trading, Midwest financial activities, oil procurement and natural gas group procurement, scheduling and hedging activities in the Trading and Dispatch Section of the Fuels and Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for the hourly trading, financial hedging activities, oil procurement and 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. 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've been either the Director Trading, Director of Natural Gas or 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. 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 2019 through July 2019.

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 2019 through March 2019.

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 2020.

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, and therefore does not have any hedges in place for 2020 or beyond.

Q. What were the results of DEF's hedging activities for January through March 2019?

A. The Company's natural gas hedging activities for the period of January 2019 through March 2019 have resulted in hedges being below the closing natural gas settlement prices by approximately $100,700**.** DEF had hedging transactions entered into under previously approved risk management plans that settled in 2019. To clarify, DEF does not have any hedges in place past March 2019 - therefore there are no results to report for April through July of 2019. 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.

(Whereupon, prefiled direct testimony was inserted.)

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190001-EI

GPIF Schedules for January through December 2018

DIRECT TESTIMONY OF JAMES BRADLEY DANIEL

March 15, 2019

Q. Please state your name and business address.

A. My name is J. Bradley Daniel. 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 Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization.

Q. Describe your responsibilities as Manager of Fuels and Fleet Analytics.

A. As Manager of Fuels and Fleet 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 2018. 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. _______ (JBD-1T), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 24-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

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

A. DEF's calculated GPIF incentive amount is a reward of $2,591,697. 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.

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 DECEMBER 2018

FPSC DOCKET NO. 20190001-EI

GPIF TARGETS AND RANGES FOR JANUARY THROUGH DECEMBER 2020

DIRECT TESTIMONY OF JAMES BRADLEY DANIEL

September 3, 2019

Q. Please state your name and business address.

A. My name is J. Bradley Daniel. 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 Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization. DEC and Duke Energy Florida, LLC ("DEF" or "Company") are both wholly-owned subsidiaries of Duke Energy Corporation ("Duke Energy").

Q. What are your responsibilities in that position?

A. As Manager 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 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. Please describe your educational background and professional experience.

A. I earned a B.A. from the University of Oklahoma in 2000 and an MBA from Wake Forest University in 2009. I interned as a data analyst with Oklahoma Energy Resources, Inc in Oklahoma City, OK in the Fall of 1999 and as an energy market research analyst with Cinergy Corporation in Cincinnati, OH in the summer of 2000. From 2001 until 2005, I worked as hourly power scheduler and power trader for Cinergy Corporation. From 2005 until 2007, I worked as a load forecast analyst and short-term power trader for Cinergy Corporation. In 2007, I transferred to a short-term power trader role for Duke Energy in Charlotte, NC, after the merger of Cinergy Corporation and Duke Power. I worked in that role while completing my MBA from Wake Forest University, with a focus in Economics. From 2010-2012, I managed the Midwest short term trading portfolio, where I took responsibility for power, natural gas, and Financial Transmission Rights hedging portfolios covering the Duke Energy Indiana and Kentucky jurisdictions. In 2012, after the Duke Energy and Progress Energy merger, I took the role of Manager, Southeast Power Trading, responsible for managing hourly purchases and sales of wholesale power for Duke Energy Carolinas and Duke Energy Florida. In 2017, I took the role of Manager, Fuels and Fleet Analytics (now Fuels and Operations Forecasting), where I took over responsibility for mid-term production cost modeling, dispatch pricing, fuel burn forecasting, position reporting, budgeting for rates and financial planning, and general analytical support for

Fuels Procurement and Hedging, Power and Gas Trading, and Unit Commitment functions for Duke Energy Carolinas (North and South Carolina), Duke Energy Florida, and Duke Energy Midwest (Indiana and Kentucky) within Duke Energy's Fuels and Systems Optimization organization.

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 2018, and outline the development of the Company's Generating Performance Incentive Factor ("GPIF") targets and ranges for the period January through December 2020. 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, 2019 testimony for the period January through December 2018?

A. DEF's calculated GPIF incentive amount for this period was a reward of $2,591,697. Please refer to my testimony filed March 15, 2019 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. _____ (JBD-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 2020 projection period, the GPIF program includes the following units: Bartow Unit 4, Hines Units 1 through 4 and Osprey Unit 1. Combined, these units account for 83% of the estimated total system net generation for the period, excluding Citrus CC. Citrus CC Units 1 and 2 were not included for the upcoming projection period since it does not meet the inclusion of performance history to use in setting targets and ranges for these units. Osprey Unit 1 was acquired by DEF in early 2017; prior to that Osprey Unit 1 was contracted for by DEF under a tolling arrangement with DEF from October 2014 through December 2016.

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. ___ (JBD-1P).

Q. How were the equivalent availability targets developed?

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

The supporting tables and graphs for the target and range rates are contained in pages 37-67 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. ___ (JBD-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 24-36 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 2020?

A. The estimated maximum incentive for the Company is $10,966,895. The calculation of the estimated maximum incentive is shown on page 3 of my Exhibit No. ___ (JBD-1P).

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20190001-EI

MARCH 1, 2019

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. 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, where my duties include 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 2018 through December 2018.

The 2018 net true-up for the FCR Clause is an under-recovery, including interest, of $70,653,875. FPL is requesting Commission approval to include this 2018 FCR Clause true-up under-recovery of $70,653,875 in the calculation of the FCR factors for the period January 2020 through December 2020.

The 2018 net true-up for the CCR Clause is an over-recovery, including interest, of $7,161,574. FPL is requesting Commission approval to include this 2018 CCR Clause true-up over-recovery of $7,161,574 in the calculation of the CCR factors for the period January 2020 through December 2020.

Finally, FPL is requesting Commission approval to include $13,442,599 in the calculation of the FCR factors for the period January 2020 through December 2020, which represents FPL's share of the 2018 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 2018 through December 2018 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 2018 FCR net true-up amount.

A. Exhibit RBD-1, page 1, titled "Summary of Net True-Up," shows the calculation of the FCR net true-up for the period January 2018 through December 2018, an under-recovery of $70,653,875.

The summary of the FCR net true-up amount shows the actual end-of-period true-up under-recovery for the period January 2018 through December 2018 of

$158,762,124 on line 1. The actual/estimated true-up under-recovery for the same period of $88,108,249 is shown on line 2. Line 1 less line 2 results in the net final true-up under-recovery for the period January 2018 through December 2018 of $70,653,875 shown on line 3.

The calculation of the FCR 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 2018 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 2018 through December 2018.

Q. Have you provided schedules showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2018?

A. Yes. Exhibit RBD-1, page 3, (sum of lines 40 and 41) compares the actual end-of-period true-up under-recovery of $158,762,124 (column 4) to the actual/estimated end-of-period true-up under-recovery of $88,108,249 (column 5) resulting in a net under-recovery of $70,653,875 (column 6). Exhibit RBD-1, page 3 lines 39 and 30, shows that the variance consists of an increase in jurisdictional fuel costs of $136.1 million partially offset by an increase in revenues of $65.5 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 $2.89 billion for 2018 (Exhibit RBD-1, page 3, line 39, column 5). The actual jurisdictional total fuel costs and net power transactions for that period is $3.02 billion (Exhibit RBD-1, page 3, line 39, column 4). Jurisdictional total fuel costs and net power transactions are $136.1 million, or 4.7% higher than previously projected (Exhibit RBD-1, page 3, line 39, column 6) and jurisdictional fuel revenues, net of revenue taxes for 2018, are $65.5 million, or 2.3% higher than previously projected (Exhibit RBD-1, page 3, line 30, column 6).

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

A. Below are the primary reasons for the $136.1 million variance.

<u>Fuel Cost of System Net Generation: $184.6 million increase (Exhibit RBD-1, page 3, line 1, column 6)</u>

The table below provides the detail of this variance.

FUEL VARIANCE	**2018 FINAL TRUE-UP**	**2018 ACTUAL/ ESTIMATED**	**DIFFERENCE**
<u>Heavy Oil</u>			
Total Dollar	$33,336,536	$18,081,040	$15,255,496
Units (MMBTU)	2,817,296	1,540,386	1,276,910
$ per Units	11.8328	11.7380	0.0948
Variance Due to Consumption			$14,988,357
Variance Due to Cost			$267,139

FUEL VARIANCE	2018 FINAL TRUE-UP	2018 ACTUAL/ ESTIMATED	DIFFERENCE
Total Variance			$15,255,496
Light Oil			
Total Dollar	$17,471,205	$23,252,266	($5,781,061)
Units (MMBTU)	1,091,030	1,564,774	(473,744)
$ per Units	16.0135	14.8598	1.1537
Variance Due to Consumption			($7,039,757)
Variance Due to Cost			$1,258,697
Total Variance			($5,781,061)
Coal			
Total Dollar	$70,954,592	$61,474,973	$9,479,619
Units (MMBTU)	28,818,876	25,345,757	3,473,119
$ per Units	2.4621	2.4255	0.0366
Variance Due to Consumption			$8,423,891
Variance Due to Cost			$1,055,728
Total Variance			$9,479,619
Gas			
Total Dollar	$2,938,221,234	$2,773,198,972	$165,022,262
Units (MMBTU)	660,577,429	631,814,389	28,763,040
$ per Units	4.4480	4.3893	0.0587
Variance Due to Consumption			$126,248,522
Variance Due to Cost			$38,773,740
Total Variance			$165,022,262
Nuclear			
Total Dollar	$175,457,637	$174,817,401	$640,236
Units (MMBTU)	308,786,317	302,463,140	6,323,177
$ per Units	0.5682	0.5780	(0.0098)
Variance Due to Consumption			$3,654,665
Variance Due to Cost			($3,014,429)
Total Variance			$640,236
Total			
Variance Due to Consumption			$124,737,240

<table>
<tr><th>FUEL VARIANCE</th><th>2018 FINAL TRUE-UP</th><th>2018 ACTUAL/ ESTIMATED</th><th>DIFFERENCE</th></tr>
<tr><td>Variance Due to Cost</td><td></td><td></td><td>$59,879,312</td></tr>
<tr><td>Total Variance</td><td></td><td></td><td>$184,616,552</td></tr>
<tr><td colspan="4">Note: Fuel Cost of System Net Generation reflected above does not tie to amounts provided on the 2018 final true-up schedule due to a reduction to nuclear fuel expense in the amount of $1.1 million. In 2018, an overstatement of nuclear fuel amortization and other adjustments occurred, which were included and footnoted on the impacted monthly A-Schedule.</td></tr>
</table>

<u>Rail Car Lease (Cedar Bay/ICL/SJRPP): $0.7 million increase (Exhibit RBD-1, page 3, line 4, column 6)</u>

The variance for rail car lease (Cedar Bay/ICL/SJRPP) is primarily attributable to higher than projected rail car lease costs for SJRPP.

<u>Variable Power Plant O&M Avoided due to Economy Purchases: $0.3 million decrease (Exhibit RBD-1, page 3, line 15, column 6)</u>

The variance for variable power plant O&M avoided due to economy purchases is attributable to lower than projected economy power purchases.

<u>Variable Power Plant O&M Attributable to Off-System Sales: $0.2 million increase (Exhibit RBD-1, page 3, line 14, column 6)</u>

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

<u>Energy Cost of Economy Purchases: $13.4 million decrease (Exhibit RBD-1, page 3, line 10, column 6)</u>

The variance for the energy cost of economy purchases is primarily attributable to lower than projected economy purchases. FPL purchased 232,638 MWh, or 410,368 MWh less of economy power resulting in a volume decrease of $15.3 million. This volume variance is partially offset by higher than projected costs for economy power. The average cost of economy power purchases was $8.41/MWh higher than projected, resulting in a cost increase of $1.9 million. The combination of lower economy power purchases coupled with higher costs for economy power purchases results in a net decrease of $13.4 million.

<u>Fuel Cost of Power Sold: $8.5 million increase (Exhibit RBD-1, page 3, line 6, column 6)</u>

The variance for the fuel cost of power sold is primarily attributable to higher than projected economy power sales. FPL sold 2,478,644 MWh, or 361,890 MWh more of economy power, resulting in a volume increase of $8.2 million. The average unit fuel cost on economy power sales was $0.10/MWh higher than projected, resulting in a cost increase of $0.2 million. The combination of higher economy power sales and higher fuel costs attributable to economy power sales results in a net increase for economy power sales of $8.4 million. The remaining variance of $0.1 million is attributable to higher than projected St. Lucie Plant Reliability Exchange sales and higher than projected fuel costs on St. Lucie Plant Reliability Exchange sales.

<u>Gains from Off-System Sales: $2.6 million increase (Exhibit RBD-1, page 3, line 7, column 6)</u>

The variance for gains from off-system sales is attributable to higher than projected economy power sales and lower than projected margins on economy power sales. FPL sold 2,478,644 MWh, or 361,890 MWh more of economy power, resulting in an increase of $4.9 million. This variance is partially offset by lower than projected margins on economy power sales. Margins on economy power sales averaged $0.93/MWh lower than projected, resulting in a decrease of $2.3 million. The combination of higher economy power sales and lower margins on economy power sales results in a net increase for gains from off-system sales of $2.6 million.

<u>Fuel Cost of Stratified Sales: $2.3 million increase (Exhibit RBD-1, page 3, line 5, column 6)</u>

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

<u>Fuel Cost of Purchased Power: $1.4 million decrease (Exhibit RBD-1, page 3, line 8, column 6)</u>

The variance for the fuel cost of purchased power is primarily attributable to lower than projected purchases under agreements with Exelon Generation Company, LLC ("ExGen") and the Orlando Utilities Commission ("OUC") and higher than projected purchases under contracts with the Solid Waste Authority of Palm Beach County ("SWA"). For ExGen, the combination of slightly lower average fuel costs coupled with 50,556 MWh less in purchases resulted in a decrease of $2.3 million. For OUC, FPL had projected $0.7 million in purchased power costs from October through December. The firm capacity and energy agreement with OUC did not begin until the latter half of December and FPL did not purchase power from OUC under the agreement, resulting in a decrease of $0.7 million. This combined variance of $3.0 million for ExGen and OUC is partially offset by higher than projected purchases from SWA. FPL purchased 861,682 MWh, or 72,833 MWh more from SWA at an average cost that was $0.88/MWh lower than projected. The combination of higher purchases and lower fuel costs for SWA resulted in an increase of $1.4 million. The remaining variance of $0.2 million is primarily attributable to higher than projected fuel costs related to St. Lucie Reliability Exchange purchases.

<u>Energy Payments to Qualifying Facilities: $0.4 million decrease (Exhibit RBD-1, page 3, line 9, column 6)</u>

The variance for energy payments to qualifying facilities is primarily attributable to lower than projected purchases and costs from As-Available Co-Gen facilities. In total, FPL purchased 214,427 MWh, or 17,847 MWh less than projected from As-Available Co-Gen facilities at an average unit fuel cost that was $0.44/MWh lower than projected. The combination of lower purchases and fuel costs for As-Available purchases resulted in a decrease of $0.5 million. This variance is partially offset by higher than projected purchases and fuel costs from FPL's Firm Co-Gen facility. FPL purchased 34,403 MWh, or 275 MWh more of Firm Co-Gen power at an average cost that was $3.20/MWh higher than projected, resulting in an increase for Firm Co-Gen power of $0.1 million.

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

A. As shown on Exhibit RBD-1, page 3, line 30, actual 2018 jurisdictional FCR revenues, net of revenue taxes, are approximately $65.5 million higher than the actual/estimated projection. This is primarily due to jurisdictional sales that are 2,231,289 MWh higher than the actual/estimated projection.

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $13,442,599 as its 60% share of 2018 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 2018 Incentive Mechanism gains through the 2020 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 2020 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 2020 through December 2020 as a reduction to jurisdictional fuel revenues applicable to each period.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2018 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 2018 through December 2018, an over-recovery of $7,161,574, which FPL is requesting to be included in the calculation of the CCR factors for the January 2020 through December 2020 period.

The actual end-of-period over-recovery for the period January 2018 through December 2018 of $13,577,483 shown on line 1 less the actual/estimated end-of-period over-recovery for the same period of $6,415,909 shown on line 2 that was approved by the Commission in Order No. PSC-2018-0610-FOF-EI, results in the net true-up over-recovery for the period January 2018 through December 2018 of $7,161,574 shown on line 3.

Q. Have you provided a schedule showing the calculation of the 2018 CCR actual true-up by month?

A. Yes. Exhibit RBD-2, pages 2 through 4, titled "Calculation of Final True-Up Amount" shows the calculation of the CCR end-of-period true-up for the period January 2018 through December 2018 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 costs and applicable revenues for 2018?

A. Yes. Exhibit RBD-2, pages 5 and 6, titled "Calculation of Final True-Up Variances," shows the actual capacity costs and applicable revenues compared to actual/estimated capacity costs and applicable revenues for the period January 2018 through December 2018.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-2, page 6, line 27, column 5, the variance related to jurisdictional capacity costs is a decrease of $3.7 million, or 1.5%, from the actual/estimated projection. The primary reason for this variance is a $3.9 million or 1.5% decrease in total system capacity costs (page 5, line 13, column 5).

Below are the primary reasons for the $3.9 million decrease in total system capacity costs.

<u>Transmission Revenues from Capacity Sales: $1.9 million increase (Exhibit RBD-2, page 5, line 12, column 5)</u>

The variance for transmission revenues from capacity sales is primarily attributable to higher revenues from capacity premiums associated with power capacity sales of $1.0 million. The remaining variance of $0.9 million is primarily due to higher than projected transmission revenues from higher than projected economy power sales.

Payments to Non-Cogenerators: $1.9 million decrease (Exhibit RBD-2, page 5, line 1, column 5)

The variance for payments to non-cogenerators (SJRPP, SWA, Exelon and OUC) is primarily attributable to lower than projected costs of approximately $1.9 million associated with the OUC agreement, and adjustments associated with SJRPP in the second half of the year. Due to the timing of Commission approval, OUC capacity payments originally expected during October and November did not occur and December costs were less than projected.

Transmission of Electricity by Others: $0.6 million decrease (Exhibit RBD-2, page 5, line 11, column 5)

The variance for transmission of electricity by others is primarily attributable to true-up adjustments of approximately $0.7 million received from Southern Company for transmission service costs related to the expired Southern Company UPS agreements. This variance is partially offset by approximately $0.1 million due to the purchase of third party transmission utilized to facilitate wholesale power sales.

Incremental Nuclear NRC Compliance Costs (Fukushima): O&M - $0.3 million increase (Exhibit RBD-2, page 5, line 9, column 5)

The variance for incremental NRC compliance O&M costs is primarily attributable to an increase in fees for FPL's share in costs to support the Regional Response Centers (a warehouse of off-site portable equipment shared by the industry).

Nuclear Cost Recovery Costs: $0.3 million decrease (Exhibit RBD-2, page 6, line 29, column 5)

The variance for nuclear cost recovery costs is attributable to a refund from the Nuclear Regulatory Commission for incorrectly billed work on contested hearings for the Turkey Point Unit 6 application. The refund amount relates to costs incurred on hearings prior to 2017.

Q. Please describe the variance in 2018 CCR revenues.

A. As shown on page 6, line 36, column 5, actual 2018 CCR revenues (net of revenue taxes), are $3.1 million higher than projected in the actual/estimated true-up filing. This is primarily due to higher than projected jurisdictional sales, which are 2,231,289 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 7 and 8. Page 7 shows the actual capacity payments for FPL's Purchase Power Agreements for the period January 2018 through December 2018. Page 8 provides the Short Term Capacity Payments for the period January 2018 through December 2018.

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 2018 through December 2018 are included on pages 18 and 19 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. 20190001-EI

JULY 26, 2019

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, 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. 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 2019 through December 2019. My testimony also provides revised 2018 FCR and CCR final net true-up amounts that reflect revisions to the amounts filed on March 1, 2019.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits with your testimony?

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 2019 through December 2019. FCR Schedules A1 through A9 provide actual data for the period January 2019 through June 2019. 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 2019 through December 2019.

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 2019 through December 2019.

Exhibit RBD-5 and Exhibit RBD-6 provide the calculation of the revised FCR and CCR final net true-up amounts 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. Have you revised the 2018 FCR and CCR final net true-up amounts that were filed in this docket on March 1, 2019?

A. Yes. The 2018 FCR final net true-up amount was revised to reflect a correction to the monthly average interest rate for the month of May. This revision decreases the actual 2018 FCR end of period true-up under-recovery amount including interest by $470 from $158,762,124 to $158,761,654. This revision decreases the 2018 FCR final net true-up under-recovery amount, including interest, from $70,653,875 to $70,653,405. Exhibit RBD-5 of my testimony provides the revised schedules reflecting the calculation of the revised 2018 FCR final net true-up under-recovery amount of $70,653,405.

The 2018 CCR final net true-up amount was also revised to reflect a correction to the monthly average interest rate for the month of May. This revision decreases the actual 2018 CCR end of period true-up over-recovery amount including interest by $65.

Additionally, the 2018 CCR final net true-up amount was revised to reflect a correction to the strata classification for a portion of the Incremental Plant Security Capital project in August and September. During these months the strata for this project was incorrectly classified as General and as a result, the jurisdictional amounts were incorrect. This revision increases the actual 2018 CCR end of period true-up over-recovery amount including interest by $210.

The combination of these revisions increases the actual 2018 CCR end-of-period over-recovery amount, including interest, by $145 from $13,577,483 to $13,577,628 and the 2018 CCR final net true-up over-recovery amount, including interest, from $7,161,574 to $7,161,719. Exhibit RBD-6 of my testimony provides the revised schedules reflecting the calculation of the revised 2018 CCR final net true-up over-recovery amount of $7,161,719.

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

A. The FCR true-up calculation compares actual/estimated data consisting of actuals for January 2019 through June 2019 and revised estimates for July 2019 through December 2019 to the data reflected in FPL's original projection for the period January 2019 through December 2019 filed on August 24, 2018. Likewise, the CCR true-up calculation compares actual/estimated data consisting of actuals for January 2019 through June 2019 and revised estimates for July 2019 through December 2019 to the data reflected in FPL's original projection for the period January 2019 through December 2019 filed on August 24, 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 2019, which reflects the interest rate from the last business day in June 2019.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2019 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 2019 through December 2019.

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 2019 end-of-period net true-up amount to be carried forward to the 2020 FCR factors is an over-recovery of $58,082,532 (page 1, line 43, column 16). This $58,082,532 over-recovery includes the revised 2018 final true-up under-recovery of $70,653,405 (Exhibit RBD-3, page 1, line 41, column 16), included in this filing as Exhibit RBD-5, and the actual/estimated true-up over-recovery, including interest, of $128,735,937 (Exhibit RBD-3, page 1, lines 38 plus 39, column 16) for the period January 2019 through December 2019.

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 2019?

A. Yes. Exhibit RBD-3, page 2 provides a variance calculation that compares the 2019 actual/estimated period data by component to the same components from the 2019 original projection filed on August 24, 2018.

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

A. FPL originally projected jurisdictional total fuel costs and net power transactions to be $2.707 billion for 2019 (Exhibit RBD-3, page 2, line 37, column 5). The actual/estimated jurisdictional total fuel costs and net power transactions are now projected to be $2.584 billion for that period (Exhibit RBD-3, page 2, line 37, column 4). The estimated variance is due to lower than projected costs and higher than projected sales and revenues. Jurisdictional total fuel costs and net power transactions are estimated to be $123.0 million, or 4.5% lower than the original projection (Exhibit RBD-3, page 2, line 37, column 6), and jurisdictional fuel revenues, net of revenue taxes are projected to be $9.0 million, or 0.3% higher than the original projection (Exhibit RBD-3, page 2, line 29, column 6). The net impact due to the decrease in jurisdictional fuel costs and the increase in jurisdictional fuel revenues result in the actual/estimated true-up over-recovery of $132.0 million (Exhibit RBD-3, page 2, line 38, column 6).

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

A. Below are the primary reasons for the $123.0 million variance in jurisdictional total fuel costs.

<u>Fuel Cost of System Net Generation: $119.2 million decrease (Exhibit RBD-3, page 2, line 1, column 6)</u>

The table below provides the detail of this variance.

Fuel Variance	**2019 ACTUAL/ ESTIMATED**	**2019 PROJECTION**	**DIFFERENCE**
<u>Heavy Oil</u>			
Total Dollar	$12,853,413	$28,288,036	($15,434,622)
Units	1,115,625	2,388,643	(1,273,018)
$ per Units	11.5213	11.8427	(0.3215)
Variance Due to Consumption			($15,075,999)
Variance Due to Cost			($358,624)
Total Variance			($15,434,622)
<u>Light Oil</u>			
Total Dollar	$11,992,197	$38,310,245	($26,318,048)
Units	706,510	2,391,861	(1,685,351)
$ per Units	16.9739	16.0169	0.9569
Variance Due to Consumption			($26,994,134)
Variance Due to Cost			$676,086
Total Variance			($26,318,048)
<u>Coal</u>			
Total Dollar	$69,189,030	$65,970,888	$3,218,142
Units	27,200,891	27,897,522	(696,631)
$ per Units	2.5436	2.3648	0.1789
Variance Due to Consumption			($1,647,364)
Variance Due to Cost			$4,865,505
Total Variance			$3,218,142

Fuel Variance	2019 ACTUAL/ ESTIMATED	2019 PROJECTION	DIFFERENCE
Gas			
Total Dollar	$2,493,615,287	$2,563,171,145	($69,555,858)
Units	637,898,271	604,568,149	33,330,122
$ per Units	3.9091	4.2397	(0.3306)
Variance Due to Consumption			$141,308,814
Variance Due to Cost			($210,864,672)
Total Variance			($69,555,858)
Nuclear			
Total Dollar	$155,046,037	$166,122,409	($11,076,371)
Units	298,655,844	301,929,301	(3,273,457)
$ per Units	0.5191	0.5502	(0.0311)
Variance Due to Consumption			($1,801,066)
Variance Due to Cost			($9,275,305)
Total Variance			($11,076,371)
Total			
Total Dollar	$2,742,695,965	$2,861,862,723	($119,166,758)
Units	965,577,141	939,175,476	26,401,665
$ per Units	2.8405	3.0472	(0.2067)

Fuel Cost of Stratified Sales: $6.6 million increase (Exhibit RBD-3, page 2, line 2, column 6)

The variance for the fuel cost of stratified sales is primarily attributable to higher than projected sales to stratified contracts, resulting in a larger credit to fuel costs.

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

The variance for gains from off-system sales is primarily attributable to higher than projected economy power sales. FPL now projects to sell 315,921 MWh more of economy power, resulting in a variance of $2.9 million. This variance is partially offset by lower than projected margins on economy power sales. FPL now projects that margins on economy power sales will be $0.35/MWh lower than originally projected, resulting in a variance of $0.9 million. The combination of higher economy power sales and lower margins on economy power sales results in a net variance of $2.0 million.

<u>Fuel Cost of Purchased Power: $1.9 million decrease (Exhibit RBD-3, page 2, line 6, column 6)</u>

The variance for the fuel cost of purchased power is primarily attributable to lower than projected purchases under the Orlando Utilities Commission ("OUC") agreement and lower than projected fuel costs for purchases under contracts with the Solid Waste Authority of Palm Beach County ("SWA"). For OUC, the combination of slightly lower average fuel costs, coupled with 42,924 MWh less in purchases, results in a total variance for OUC of $1.7 million. For SWA, FPL projects to purchase 73,060 MWh more than originally projected. However, fuel costs are now projected to be $3.66/MWh lower than originally projected, resulting in a decrease for SWA of $0.7 million. The combined variance for OUC and SWA of $2.4 million is partially offset by a variance of $0.5 million related to higher than projected purchases and fuel costs under the St. Lucie Reliability Exchange.

Energy Payments to Qualifying Facilities: $0.5 million decrease (Exhibit RBD-3, page 2, line 7, column 6)

The variance for energy payments to qualifying facilities is primarily attributable to lower than projected fuel costs from As-Available Co-Gen facilities. FPL projects to purchase 11,104 MWh more than originally projected. However, fuel costs are now projected to be $3.08/MWh lower than originally projected, resulting in a decrease for As-Available purchases of $0.6 million. This variance is slightly offset by an increase of $0.1 million related to higher than projected purchases and fuel costs from Firm Co-Gen facilities.

Variable Power Plant O&M Avoided due to Economy Purchases: $0.1 million increase (Exhibit RBD-3, page 2, line 13, column 6)

The variance for variable power plant O&M avoided due to economy purchases is primarily attributable to higher than originally projected economy power purchases.

Energy Cost of Economy Purchases: $9.9 million increase (Exhibit RBD-3, page 2, line 8, column 6)

The variance for the energy cost of economy purchases is attributable to higher than projected economy power purchases and higher than projected costs for economy power purchases. FPL now projects to purchase 77,651 MWh more of economy power resulting in a volume variance of $2.0 million. FPL also projects that the average cost of economy power purchases will be $12.64/MWh higher than originally projected, resulting in a cost variance of $7.9 million. The combination of higher economy power purchases coupled with higher costs for economy power purchases results in a net variance of $9.9 million.

<u>Fuel Cost of Power Sold: $4.8 million decrease (Exhibit RBD-3, page 2, line 4, column 6)</u>

The variance for the fuel cost of power sold is primarily attributable to lower than projected fuel costs for economy power sales and higher than projected economy power sales. FPL now projects to sell 315,921 MWh more than projected, resulting in a volume increase of $7.8 million. However, the average unit fuel cost on economy power sales is now projected to be $4.74/MWh lower than originally projected, resulting in a cost decrease of $11.9 million. The combination of the higher volume and lower fuel costs results in a net decrease for economy power sales of $4.1 million. The remaining variance of $0.7 million is primarily attributable to lower than projected St. Lucie Plant Reliability Exchange sales.

<u>Variable Power Plant O&M Attributable to Off-System Sales $0.2 million increase (Exhibit RBD-3, page 2, line 12, column 6)</u>

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

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2019 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 2019 through December 2019.

Q. Please explain the calculation of the CCR 2019 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 2019 through June 2019 reflects actual data, while the data for July 2019 through December 2019 is based on updated estimates) compared to the original projection filing for the January 2019 through December 2019 period. The CCR revenues (net of revenue taxes) are projected to be $5,453,289 (Exhibit RBD-4, page 5, line 33, column 5) higher than FPL's original projection filing. Jurisdictional total capacity costs are estimated to be $3,284,995 lower than the original projection filing (Exhibit RBD-4, page 5, line 27, column 5). The $3,284,995 over-recovery due to lower jurisdictional capacity costs combined with the $5,453,289 increase in revenues, results in the 2019 actual/estimated true-up over-recovery amount of $9,002,615, including interest (Exhibit RBD-4, page 5, lines 37 plus 38, column 5).

As shown on Exhibit RBD-4, page 3, the 2019 end-of period net true up amount to be carried forward to the 2020 CCR factors is an over-recovery of $16,164,334 (line 13, column 15). This $16,164,334 net over-recovery is comprised of the revised 2018 final true-up over-recovery of $7,161,719 (line 11, column 15) included in this filing as Exhibit RBD-6 and the actual/estimated true-up over-recovery, including interest, of $9,002,615 for the period January 2019 through December 2019 (lines 8 plus 9, 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 $3.4 million or 1.3% less than projected in FPL's original projection filing. The variance related to the jurisdictional portion of these costs is a 1.3% decrease from the original projection (page 5, line 27, column 6).

Below are the primary reasons for the estimated $3.4 million decrease in total system capacity costs.

<u>Incremental Plant Security O&M Costs: $3.6 million decrease (Exhibit RBD-4, page 4, line 6, column 5)</u>

The variance for incremental plant security is primarily attributable to the implementation of cost savings initiatives at the St. Lucie and Turkey Point plants resulting in lower security force costs and a decrease in the associated insurance costs.

Additionally, costs were incorrectly charged to the capacity clause in 2018. A correction was made in January to move costs from the capacity clause to base rates.

Transmission Revenues from Capacity Sales: $1.4 million increase (Exhibit RBD-4, page 4, line 11, column 5)

The variance for transmission revenues from capacity sales is primarily attributable to $0.9 million higher than projected revenues from economy sales. Additionally, higher than projected revenues from capacity premiums resulted in a variance of approximately $0.5 million.

Transmission of Electricity by Others: $0.2 million decrease (Exhibit RBD-4, page 4, line 10, column 5)

The variance for transmission of electricity by others is primarily due to lower costs than originally projected for the purchase of third party transmission utilized to facilitate wholesale power sales in the first half of the year. This decrease is partly offset by slightly higher than originally projected third party transmission costs in the second half of the period.

Incremental Nuclear Compliance O&M Costs: $0.8 million increase (Exhibit RBD-4, page 4, line 8, column 5)

The variance for incremental nuclear compliance O&M costs is primarily attributable to modifications at Turkey Point required to address higher than anticipated water levels following a beyond design basis threat. Modifications include sealing of critical equipment access points and raising the height of existing flood barriers.

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 20190001-EI?

A. Yes. The capital structure components and cost rates used to calculate the rate of return on capital investments for the period January 2019 through December 2019 are included on pages 16 and 17 of Exhibit RBD-4.

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. 20190001-EI

SEPTEMBER 3, 2019

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, 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 the following periods: (i) January 2020 through April 2020, and (ii) May 2020 through December 2020, reflecting the fuel savings associated with the four solar energy centers expected to enter commercial operation by May 1, 2020 ("2020 Project");

- The 2020 FCR factors based on the traditional factor calculation method, which spreads the fuel savings associated with the 2020 Project over the entire calendar year, for informational purposes;
- The calculation of the jurisdictional amount of FPL's portion of the 2018 incentive mechanism gains for recovery through the 2020 FCR factors;
- The Capacity Cost Recovery ("CCR") Clause factors for the period January 2020 through December 2020 and the CCR factors for the same period, including a refund for the 2017 SoBRA true-up, and 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 2020 through December 2020; 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-7 (Appendix II)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation, and E10 provide the calculation of FCR factors for January 2020 through April 2020, which exclude fuel savings for the 2020 Project;

- Schedules E1-A, E1-C, E1-D, Calculation of Jurisdictional Incentive Mechanism Gains – FPL Portion, and H1, which pertain to the entire 2020 calendar year;
- Pages 9 through 12, which provide the 2020 Projected Energy Losses by Rate Class;
- Pages 78 and 79, which provide updated COG-1 tariff sheets;

Exhibit RBD-8 (Appendix III)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation, and E10 for the period May 2020 through December 2020, which include fuel savings for the 2020 Project;

Exhibit RBD-9 (Appendix IV)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 that provide the calculation of FCR factors for the period January 2020 through December 2020 based on the traditional factor calculation methodology, which spreads fuel savings for the 2020 Project over the entire calendar year;

Exhibit RBD-10 (Appendix V)

- Pages 1 through 4 provide the calculation of the 2020 CCR factors including the refund for the 2017 SoBRA true-up, and excluding the Indiantown non-fuel revenue requirements for January 2020 through December 2020;
- Pages 5 through 10 provide the calculation of depreciation and return on incremental power plant security and incremental Nuclear

Regulatory Commission ("NRC") compliance capital investments;

- Page 11 provides the calculation of amortization and return on the regulatory asset related to the Cedar Bay Transaction;
- Page 12 provides the calculation of amortization and return on the regulatory liability related to the Cedar Bay Transaction;
- Page 13 provides the calculation of amortization and return on the regulatory asset related to Indiantown;
- Page 14 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 15 provides the capital structure components and cost rates relied upon to calculate the rate of return applied to capital investments and working capital amounts included for recovery through the CCR clause for the period January 2020 through December 2020;
- Pages 18 and 19 provide the calculation of the portion of the CCR factors that recovers the non-fuel revenue requirements associated with Indiantown for the period January 2020 through December 2020;
- Page 20 combines the results from pages 1 through 4 and pages 18 and 19 to provide the total 2020 CCR factors including the non-fuel revenue requirements associated with Indiantown for the period January 2020 through December 2020;
- Pages 21 and 22 provide the calculation of the Indiantown revenue

- requirements for January 2020 through December 2020;
- Pages 23 through 32 provide the calculations of stratified separation factors.

FUEL COST RECOVERY CLAUSE

Q. What adjustments are included in the calculation of the 2020 FCR factors shown on Schedules E1 included in Appendices II through IV?

A. The 2020 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 2018 incentive mechanism gains. The total net true-up to be included in the 2020 FCR factors is an over-recovery of $58,082,532, as shown on line 30 of Schedule E1.

The GPIF testimony of witness Charles R. Rote, filed on March 15, 2019, proposes a reward of $8,577,071 for the period ending December 2018, as shown on line 34 of Schedule E1.

FPL is including $12,786,460 for the jurisdictional amount associated with its share of 2018 incentive mechanism gains in the calculation of its 2020 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 1, 2019 in this docket, FPL's activities under the incentive mechanism in 2018 delivered $62,404,332 in total gains. Of these total gains, FPL is allowed to retain $13,442,599 (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 $12,786,460, net of revenue taxes, in each month's Schedule A2 for the period January 2020 through December 2020 as a reduction to jurisdictional fuel revenues applicable to each period. The calculation of the jurisdictional amount of the 2018 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 $23,890,327 associated with stratified wholesale power sales contracts in effect in 2020. The fuel costs for wholesale power contracts 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.

Q. Has FPL included any other adjustment to the calculation of the 2020 FCR factors?

A. Yes. FPL has included the cost associated with the 2020 Subscription Credit for the proposed FPL SolarTogether Program discussed in the direct testimony of FPL witness Scott Bores filed on July 29, 2019 in Docket No. 20190061-EI. This is discussed further in my testimony below.

Calculation of 2020 FCR Factors

Q. Please explain how FPL has calculated its proposed FCR factors for the period January 2020 through December 2020 to reflect the impact of the fuel savings associated with the 2020 Project.

A. Pursuant to the Stipulation and Settlement Agreement reached in FPL's 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 2020 Project. The SoBRA associated with the 2020 Project is expected to be implemented by May 1, 2020. FPL proposes that the corresponding fuel savings associated with the 2020 Project be reflected in the 2020 FCR factors concurrent with the SoBRA adjustment 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 date of the 2020 Project impact the 2020 FCR factors?

A. At this time, FPL does not anticipate a delay in the commercial operation date of the 2020 Project. Should FPL become aware of a delay, FPL will promptly provide notification to the Commission of such delay and provide an updated in-service date. FPL will not implement the 2020 SoBRA until those units go into service.

Q. What are the projected 2020 fuel savings associated with the 2020 Project?

A. As explained in the testimony of FPL witness Yupp, the projected 2020 total system fuel savings associated with the 2020 Project are $11,149,004.

Q. Please explain the calculation of 2020 FCR factors reflecting the fuel savings associated with the 2020 Project.

A. FPL first calculates the FCR factors for January 2020 through April 2020 that exclude the fuel savings associated with the 2020 Project. These FCR factors assume the 2020 Project are not yet operating and therefore exclude the associated fuel savings. This adjustment is reflected on line 2 of Schedule E1 in Appendix II. The levelized FCR factor for January 2020 through April 2020 including these adjustments is 2.252 cents per kWh. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $19.25 during this period.

Next, FPL calculates the FCR factors for May 2020 through December 2020 that include the fuel savings associated with the 2020 Project that is scheduled to go in-service by May 1, 2020. This adjustment is shown on line 36 of Schedule E1 in Appendix III. The levelized FCR factor for May 2020 through December 2020 including this adjustment is 2.238 cents per kWh. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $19.11 for this period.

Schedule E2 provides the monthly fuel factors as well as the levelized FCR factor for 2020. Schedule E-1E provides the calculation of the 2020 FCR factors by rate group for each period.

Q. Has FPL also calculated levelized FCR factors that would apply uniformly throughout calendar year 2020?

A. Yes. Although FPL requests approval of separate FCR factors for two periods, reflecting the impact of the 2020 Project in those periods, FPL provides for informational purposes the calculation of a twelve-month levelized fuel factor for 2020. Appendix IV includes Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10, which calculate a twelve-month levelized fuel factor of 2.242 cents per kWh by including the fuel savings for the 2020 Project throughout the twelve months of 2020.

Q. Please briefly explain the cost of the 2020 Subscription Credit associated with the proposed FPL SolarTogether Program.

A. If approved by the Commission, the 2020 Subscription Credit associated with the proposed FPL SolarTogether Program is projected to be $31,975,895, which is reflected on Schedule E1. As discussed in the direct testimony of FPL witness Bores filed on July 29, 2019 in Docket No. 20190061-EI, the Subscription Credit reflects system savings attributable to the avoided generation resulting from the addition of the six FPL SolarTogether Centers that are scheduled to go into service in 2020. If the Commission does not approve or modifies the FPL SolarTogether Program, FPL will submit revised schedules reflecting the Commission's order.

Q. What are the projected 2020 fuel savings associated with the FPL

SolarTogether Program?

A. As explained in the testimony of FPL witness Yupp, the projected 2020 total system fuel savings associated with the FPL SolarTogether Program are $18,694,958. These system fuel savings serve as an offset to the Subscription Credit of $31,975,895. As discussed in FPL witness Bores' testimony, the amount of the Subscription Credit being paid to participants is projected to exceed the actual system savings during the early years; however, the actual annual clause system savings are projected to be greater than the credit paid to participants over the life of the Program.

<u>CAPACITY COST RECOVERY CLAUSE</u>

Q. Have you prepared a summary of the requested capacity costs for the projected period of January 2020 through December 2020?

A. Yes. Pages 1 and 2 of Appendix V provides this summary. Total recoverable capacity costs for the period January 2020 through December 2020 are $233,943,004 (page 2, line 37). This includes $256,597,002 for 2020 projected jurisdictional capacity costs, the net true-up over-recovery for 2018 and 2019 of $16,164,334 (line 32 plus line 33), a $6,657,982 refund associated with the 2017 SoBRA true-up, and revenue taxes. This $233,943,004 excludes the 2020 Indiantown non-fuel revenue requirements.

Q. **Please describe the adjustment associated with the true-up of the 2017 SoBRA.**

A. Pursuant to the 2016 Base Rate Settlement Agreement, a true-up of the SoBRA is required if actual capital costs are lower than projected. As such, FPL has included a credit of $6.7 million, including interest, (Appendix V, page 1, line 34) for the true-up of 2017 SoBRA costs as a reduction in the calculation of its 2020 CCR factors. The calculation of this credit is discussed in the testimony and exhibits of FPL witness Edward J. Anderson.

Q. What are the projected Indiantown jurisdictional non-fuel revenue requirements for the January 2020 through December 2020 period?

A. The jurisdictional non-fuel revenue requirements for January 2020 through December 2020 are $3,687,779. The calculation of this amount is shown on Exhibit RBD-10, Appendix V. FPL has made an adjustment for the Indiantown non-fuel revenue requirements consistent with the method previously used when the West County Energy Center Unit 3 ("WCEC3") non-fuel revenue requirements were recovered through the CCR as approved in Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013.

Q. Has FPL requested to modify the method used to calculate the weighted average cost of capital ("WACC") to be applied to recoverable investments in its cost recovery clauses?

A. Yes. FPL filed an Unopposed Joint Motion to Modify Order No. PSC-12-0425-PAA-EU ("2012 WACC Order") Regarding Weighted Average Cost of Capital Methodology ("Joint Motion") on August 21, 2019 in this docket to incorporate an adjustment to accumulated deferred federal income taxes, if needed, in order to comply with Internal Revenue Service Normalization Rules. As stated in the Joint Motion, a modified WACC methodology would apply only in instances when the

Limitation Provision is not met, i.e., a forecasted test period is used to set rates and the depreciation-related Accumulated Deferred Federal Income Tax ("ADFIT") balance used for ratemaking purposes is less than or equal to the ADFIT projected for the period in which the new rates take effect.

Q. Is FPL proposing to apply a WACC calculation to its 2020 CCR recoverable investments different than what is currently required under the 2012 WACC Order?

A. No. FPL has met the Limitation Provision, i.e., FPL's projected 2020 ADFIT is higher than the level included in FPL's WACC reflected in its May 2019 Earnings Surveillance Report, therefore no adjustment to its WACC methodology is required. As stated in the Joint Motion, the WACC methodology currently prescribed in the 2012 WACC Order should be applied to projected recoverable investments as long as FPL's Limitation Provision required under the Internal Revenue Code is met or exceeded.

Q. Have you provided a calculation of 2020 CCR factors by rate class including an adjustment to recover the non-fuel revenue requirements associated with Indiantown for the period January 2020 through December 2020?

A. Yes. As approved in Order No. PSC-16-0506-FOF-EI, FPL has included on pages 18 and 19 of Exhibit RBD-10, Appendix V, the 2020 non-fuel revenue requirements associated with Indiantown of $3,687,779. Accordingly, page 20 of Exhibit RBD-10, Appendix V, shows the calculation of the 2020 CCR factors including the non-fuel revenue requirements associated with Indiantown for the period January 2020 through December 2020.

Q. Has FPL accounted for stratified wholesale power sales contracts in the jurisdictional separation of projected 2020 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. The stratified separation factors are provided in Appendix V, pages 23-31.

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

A. Yes. Page 3 of Appendix V provides this calculation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Q. What are the effective dates that FPL is requesting for the new FCR and CCR factors for 2020?

A. FPL is requesting that the January 2020 FCR factors and the CCR factors for the period January 2020 through December 2020 become effective starting with meter readings made on or after January 1, 2020. FPL is also requesting that the FCR factors for the period May 2020 through December 2020 become effective coincident with the in-service date of the 2020 Project, which is expected to be by May 1, 2020. These factors should remain in effect until modified by this Commission.

Proposed 2020 Residential Bill

Q. What is FPL's proposed residential 1,000 kWh bill for the period January 2020 through December 2020?

A. FPL's proposed residential 1,000 kWh bill for January 2020 through April 2020 is $96.33. This proposed bill includes a base rate charge of $69.43, an FCR charge of $19.25, a CCR charge of $2.30, an environmental cost recovery charge of $1.55, a conservation cost recovery charge of $1.39 and gross receipts tax of $2.41.

Once the 2020 Project is placed in-service, projected to be by May 1, 2020, FPL's base rate charge will increase to $69.94 to reflect the application of the SoBRA, consistent with the 2016 Base Rate Settlement Agreement and the FCR charge will decrease to $19.11 to include the associated fuel savings. FPL's proposed residential 1,000 kWh bill for the period May 2020 through December 2020 is $96.71.

FPL's proposed residential 1,000 kWh bills for 2020 are provided on Schedule E-10, which is page 7 of Appendix IV.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20190001-EI

MARCH 1, 2019

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 2018 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 from a third party in the form of an Asset Management Agreement (AMA). Under the modified Incentive Mechanism, customers receive 100% of the gains up to the sharing threshold of $40 million. Incremental gains above $40 million are 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.

In addition, FPL recovers the net amount of variable power plant O&M incurred during the year. This is accomplished by multiplying the per-MWh variable power plant O&M rate times the volume (MWh) of economy sales and then subtracting the per-MWh variable power plant O&M rate times the volume (MWh) of economy purchases. 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 utilizes to calculate these costs, as described in FPL's

2017 Test Year MFRs filed with the 2016 Rate Petition, is $0.65/MWh. Finally, FPL is allowed to recover reasonable and prudent incremental O&M costs incurred in implementing the expanded optimization program under the Incentive Mechanism, including incremental personnel, software and associated hardware costs.

Q. Please summarize the activities and results of the Incentive Mechanism for 2018?

A. FPL's activities under the Incentive Mechanism in 2018 delivered $62,404,332 in total gains. During 2018, 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 Asset Management Agreements related to a small portion of upstream gas transportation during 2018. The total gains of $62,404,332 exceeded the sharing threshold of $40 million. Therefore, the incremental 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 2018.

Q. Please provide the details of FPL's wholesale power activities under the Incentive Mechanism for 2018.

A. The details of FPL's 2018 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-1. FPL had gains of $32,462,909 on wholesale sales and savings of $7,943,114 on wholesale purchases for the year.

Q. Please provide the details of FPL's asset optimization activities under the Incentive Mechanism for 2018.

A. The details of FPL's 2018 asset optimization activities are shown on Page 3 of Exhibit GJY-1. FPL had a total of $21,998,309 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 2018?

A. No. FPL did not engage in any new forms of asset optimization activities during 2018.

Q. Did FPL incur incremental O&M expenses related to the operation of the Incentive Mechanism in 2018?

A. Yes. FPL incurred personnel expenses of $458,689 related to the costs associated with an additional two and one-half personnel required to support FPL's expanded activities under the Incentive Mechanism. FPL also incurred $57,762 in expenses related to licensing fees of OATI WebTrader software. In total, FPL incurred incremental O&M expenses related to the operation of the Incentive Mechanism of $516,451 in 2018.

On the variable power plant O&M side, FPL's actual net economy power sales and purchases totaled 2,246,006 MWh (2,478,644 MWh of economy sales and 232,638 MWh of economy purchases), resulting in net variable power plant O&M costs of $1,459,905 for 2018.

Q. Overall, were FPL's activities under the Incentive Mechanism successful in 2018?

A. Yes. FPL's activities under the Incentive Mechanism were highly successful in 2018. On the wholesale power and natural gas optimization side, suitable market conditions in the winter period helped drive strong wholesale power sales and natural gas optimization activities and high demand during the late summer/early fall 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 $40.4 million in customer benefits. Asset optimization activities related to natural gas resulted in significant customer benefits of nearly $22 million. In total, these activities delivered $62,404,332 of gains, which contrast very favorably to the total optimization expenses (personnel and variable power plant O&M) of $1,976,355.

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. 20190001-EI

SEPTEMBER 3, 2019

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 2018 and the Incremental Optimization Costs included in FPL's 2020 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 May 1, 2020 and the projected fuel savings resulting from the commercial operation of six new solar energy centers estimated to be placed into service on February 1, 2020 as part of FPL's SolarTogether Program.

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-2: Appendix I

and I am co-sponsoring:

- Schedules E2 through E9 of Appendix II included in Renae Deaton's Exhibit RBD-7 and Schedule E2 of Appendix III and IV included in Renae Deaton's Exhibits RBD-8 and RBD-9, respectively.

<u>FUEL PRICE FORECAST</u>

Q. What forecast methodologies did FPL use for the 2020 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 26, 2019 for its 2020 projection filing, which is the most current information that could be incorporated into FPL's schedule for calculating the 2020 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 2020 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 August 2019 Short-Term Energy Outlook, the Energy Information Administration ("EIA") forecasts Henry Hub natural gas spot prices will average approximately \$2.36 per MMBtu in the second half of 2019. The EIA expects natural gas prices to increase to an average of \$2.75 per MMBtu in 2020 in order to bring supply into balance with domestic and rising export demand. Natural gas production is estimated to grow by an average rate of roughly 9% in 2019 (compared to 2018 levels) and 1.6% in 2020 (compared to 2019 levels).

Total natural gas consumption is forecast to increase by roughly 3% in 2019 (compared to 2018) before slightly decreasing in 2020. For 2019, increases in natural gas consumption are mainly due to higher use in the electric power sector. The increase in 2019 also reflects higher commercial and industrial demand compared to 2018. For 2020, power sector consumption is projected to decrease compared to 2019 and industrial demand is expected to increase. Overall, total natural gas consumption in 2020 is projected to decrease slightly compared to 2019 consumption levels. Natural gas storage levels ended July 2019 at roughly 2.7 trillion cubic feet, or 13% higher than levels at the end of July 2018 and 4% lower than the five-year average. Natural gas storage levels are expected to reach approximately 3.7 trillion cubic feet at the end of October 2019, which would be 16% higher than October 2018 and slightly above the five-year average level for the end of October.

Q. Please describe FPL's natural gas transportation portfolio for the January through December 2020 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 from January through April 2020, increasing to 600,000 MMBtu/Day beginning on May 1, 2020. Additionally, FPL projects that during the January 2020 through December 2020 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 (e.g., 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 14% 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 2020 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 (GJY-2).

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2020 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 August 2019 Short-Term Energy Outlook report, the EIA forecasts West Texas Intermediate crude oil prices will average approximately $57.87 per barrel in 2019 and $59.50 per barrel in 2020. The EIA anticipates global crude oil and other liquid fuels production to grow by 0.3 million barrels per day in 2019 and 1.5 million barrels per day in 2020, with consumption growing by approximately 1.0 million barrels per day in 2019 and 1.43 million barrels per day in 2020. U.S. crude oil and liquid fuels production is projected to increase by roughly 1.85 million barrels per day in 2019 and 1.54 million barrels per day in 2020. 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 2020 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 (GJY-2).

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 2020 period.

A. FPL's projection for the system average dispatch cost of light oil, by month, is provided on page 3 of Appendix I (GJY-2).

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 2020 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 (GJY-2).

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.

PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY

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 the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2020?

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 2020.

Q. Please describe the significant planned outages for the January through December 2020 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 2 is scheduled to be out of service from February 17, 2020 until March 17, 2020, or 29 days during the period. Turkey Point Unit 3 is scheduled to be out of service from March 30, 2020 until April 28, 2020, or 29 days during the period. Turkey Point Unit 4 is scheduled to be out of service from October 5, 2020 until November 14, 2020, or 40 days during the period.

Q. Please identify any changes to FPL's fossil generation capacity projected to take place during the January through December 2020 period.

A. As shown in FPL's 2019 Ten Year Power Plant Site Plan (Table ES-1, page 14), FPL projects a net increase in its 2020 summer firm capacity of 600 MW. Increases to FPL's generation capacity include roughly 189 MW of capacity upgrades at several of FPL's existing combined cycle units and the addition of 413 MW of solar generation. Decreases to FPL's generation capacity are the result of solar degradation (2 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 2020?

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 2,392,590 MWh of wholesale (off-system) power sales for the period of January through December 2020. The projected fuel cost related to these sales is $44,131,343. The projected transaction revenue from these sales is $72,345,309. After taking into account the transmission costs and capacity revenues for those sales, the projected gain is $22,134,432.

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 2020 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 521,230 MWh at a cost of $12,462,935. If FPL generated this energy, FPL estimates that it would cost $15,199,556. Therefore, these purchases are projected to result in savings of $2,736,621.

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 a firm capacity and energy agreement with Orlando Utilities Commission ("OUC") through December 31, 2020. 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 2020 period.

A. Energy purchases under the SWA agreements are projected to be 868,949 MWh for the period at an energy cost of $24,654,165. Energy purchases from OUC are projected to be 18,606 MWh for the period at an energy cost of $633,122. 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 599,616 MWh at a cost of $2,793,132. 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 276,013 MWh at a cost of $4,967,246.

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 631,766 MWh of energy at a cost of $3,095,400. 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 2020, 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's fuel hedging program is under a moratorium during the Minimum Term of the Agreement.

Q. Has FPL filed a Hedging Activity Final True-Up Report for 2018, consistent with the Hedging Order Clarification Guidelines, as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. No. Pursuant to Paragraph 16 of the 2016 Base Rate Settlement Agreement, FPL's fuel hedging program is under a moratorium. Therefore, FPL had no hedging activity to report for 2018.

<u>THE INCENTIVE MECHANISM</u>

Q. What were the results of FPL's asset optimization activities under the Incentive Mechanism in 2018?

A. FPL's asset optimization activities in 2018 delivered total benefits of

$62,404,332. 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 $48,596,497 (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 $13,442,599. FPL included its share of the gain in the 2020 FCR Clause factors.

Q. Did the Incentive Mechanism allow FPL to deliver greater value to customers in 2018?

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 approximately $42 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 $39.6 million, while FPL would have received $2.4 million in benefits because the three-year rolling average threshold for wholesale sales would 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 $22 million of additional savings in 2018. When one takes into account these additional savings, less FPL's recovery of incremental optimization costs, the result is that FPL's customers received $48.6 million of savings under the Incentive Mechanism. This is $9 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 2020 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 2020.

Q. Has FPL included in its 2020 FCR factors, projections of the Incremental Optimization Costs that it will incur under the Incentive Mechanism?

A. Yes. FPL has included in its 2020 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 $439,242 in 2020 for the salaries and expenses related to employees who were added in 2013 to support the Incentive Mechanism. FPL is also projecting to incur $24,454 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 2020 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 2,392,590 MWh and purchase 521,230 MWh of economy power. Therefore, applying FPL's VOM rate of $0.65/MWh, FPL projects to incur VOM expenses of $1,555,184 associated with its economy sales and to avoid ($338,800) with its economy purchases. FPL has included for recovery the net of these two figures, $1,216,384 (Schedule E2, Sum of Line Nos. 14 and 15), in its 2020 FCR factors.

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

Q. Please describe the PV generation that FPL will put into commercial operation during 2020 pursuant to the 2016 Base Rate Settlement Agreement.

A. The PV generation to be constructed pursuant to the 2016 Base Rate Settlement will consist of four solar energy centers ("the 2020 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 May 1, 2020. These four sites consist of Echo River, Hibiscus, Okeechobee, and Southfork.

Q. Will the operation of PV generation during 2020 result in fuel savings for FPL's customers?

A. Yes. For the May through December 2020 period, the operation of the 2020 Project is projected to result in fuel savings for FPL's customers of $11,149,004.

Q. How did FPL calculate the projected fuel savings associated with the operation of the 2020 Project?

A. FPL utilized its GenTrader model to quantify the fuel savings associated with the operation of the 2020 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 2020 Project and one with the 2020 Project. A comparison of the total system fuel costs from GenTrader for the two simulations showed that the fuel costs were $11,149,004 lower in the case that included the 2020 Project than in the case without the 2020 Project.

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE COMMERCIAL OPERATION OF PV GENERATION FOR THE FPL SOLARTOGETHER PROGRAM

Q. Please describe the PV generation that FPL will put into commercial operation during 2020 for the FPL SolarTogether Program.

A. The PV generation for the SolarTogether Program will consist of six solar energy centers located at six sites. The six solar energy centers are sized to generate a total of 447 MW (nameplate capacity) and are scheduled to go into service by February 1, 2020. These six sites consist of ST Project 1 Sites 1, 2, and 3, and ST Project 2 Site 1, 2, and 3.

Q. Will the operation of PV generation during 2020 for the SolarTogether Program reduce fuel costs for FPL's customers?

A. Yes. For the February through December 2020 period, the operation of the 2020 Project is projected to reduce fuel costs by $18,694,958.

Q. How did FPL calculate the projected fuel savings associated with the operation of the FPL SolarTogether Program sites scheduled to enter service in 2020?

A. FPL utilized its GenTrader model to quantify the fuel savings associated with the operation of the SolarTogether Program sites. 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 SolarTogether Program sites and one with the SolarTogether Program sites. A comparison of the total system fuel costs from GenTrader for the two simulations showed that the fuel costs were $18,694,958 lower in the case that included the SolarTogether Program sites than in the case without the SolarTogether Program sites.

Q. Does this conclude your testimony?

A. Yes it does.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ROBERT COFFEY

DOCKET NO. 20190001-EI

SEPTEMBER 3, 2019

Q. Please state your name and address.

A. My name is Robert Coffey. 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 Corporate Support in the Nuclear Business Unit.

Q. Please describe your duties and responsibilities.

A. I am responsible for the Nuclear fleet functional areas of Engineering, Operations, Maintenance, Chemistry, Radiation Protection, Regulatory Affairs, Security, Training, Outages and Projects.

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

A. I hold a Doctorate of Management in Organizational Leadership from the University of Phoenix, Masters of Business Administration degree from Regis University, and a Bachelor of Science degree in Nuclear Engineering Technology from Thomas Edison State College. I also earned a Senior Reactor Operator Management Certification at the Turkey Point Nuclear Power Plant.

I have spent 37 years in the nuclear industry, beginning in the United States Navy Nuclear Submarine Force where I served more than 20 years and retired as a senior chief electrician. I joined FPL in 2003 and held numerous positions of increasing responsibility including Maintenance Director and Work Control Manager at Turkey Point and Plant General Manager at St. Lucie. I was also the Site Vice President of NextEra Energy's Point Beach Nuclear Plant and Vice President of the Southern Region for St. Lucie and Turkey Point before serving in my current role as Vice President of Corporate Support.

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 to be produced by our nuclear units measured in Million British Thermal Units or ("MMBtu"). Nuclear fuel costs were input values to the GenTrader model that is used to calculate the costs included in the proposed fuel cost recovery factors for the period January 2020 through December 2020. I am also supporting FPL's projected 2020 incremental plant security and Fukushima-related costs. Finally, I address 2019 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 its nuclear units and current operating schedules, for the period January 2020 through December 2020.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2020 through December 2020.

A. FPL projects the nuclear units will burn 298,741,994 MMBtu of energy at a cost of $0.4873 per MMBtu for the period January 2020 through December 2020. 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 2020 through December 2020?

A. FPL projects that it will incur $38.0 million in incremental nuclear power plant security costs in 2020. The costs consist of $8.0 million of capital expenditures and $30.0 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 10 CFR 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 the NRC's physical security rule under 10 CFR. Part 73; and impacts of implementing the NRC's cyber security rule under 10 CFR Part 73. 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.

<u>Fukushima-Related Costs</u>

Q. What is FPL's projection of Fukushima-related costs at its nuclear power plants for the period January 2020 through December 2020?

A. FPL's current projection of Fukushima-related costs for 2020 is approximately $1.0 million of O&M expenses and $10.0 million of capital.

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 2020:

- 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 the Turkey Point Unit 3 and 4 A, B and C Reactor Coolant Pump seals during the Spring and Fall 2020 outages.

<u>2019 Unplanned Outage Events</u>

Q. Has FPL experienced any unplanned outages at any of its nuclear plants in 2019?

A. Yes. In April 2019, St. Lucie Unit 1 automatically shut down in response to a generator ground relay fault, and in May 2019, Turkey Point Unit 3 shut down in response to a grid disturbance. FPL's response to each unplanned outage was appropriate and efficient, and the units were returned to service safely.

Q. Please describe the circumstances related to the St. Lucie Unit 1 generator ground relay fault.

A. During plant operations, St. Lucie Unit 1 automatically shut down due to a generator ground relay fault. FPL determined the ground relay fault was attributed to an insulation fault located in stator bar B17. The cause of the insulation fault could not be definitively confirmed. Based on the location of the insulation, however, FPL believes the mechanism that produced the fault was introduced in the stator during a generator rewind performed by Siemens Energy Incorporated ("Siemens") in 2012 and degraded the insulation gradually over the course of seven years in service. FPL's investigation ruled out many potential causes, but three possible causes hypothesized were neither refuted nor adequately supported: (1) a ferromagnetic particle introduced during installation of the stator bar, (2) impact damage during handling, or installation of the stator bar or (3) a contaminant or small object introduced in the stator bar insulation during its manufacture or construction.

Q. Were periodic inspections performed on the Unit 1 generator following the generator rewind in 2012?

A. Yes. Generator inspections were performed by Siemens during every refueling outage since the rewind was completed in 2012. In 2013, generator temperature instruments were replaced. Subsequent over-voltage testing was completed after the replacement with no issues. In 2016, a ground condition was detected during outage inspection activities. The ground was outside the generator in the neutral ground transformer bushing. Neither of these activities are related to the ground fault in 2019. The type and frequency of inspections performed on the generator since the rewind adhere to standard industry practice and manufacturing recommendations.

Q. What corrective actions were initiated to address this event?

A. After inspections and testing were conducted, FPL and Siemens determined a full rewind of the generator was the best course of action to take in order to achieve maximum reliability of the generator and the safest and most efficient return to service possible. After the completion of the rewind, High Potential Testing was conducted to ensure satisfactory results.

Q. Did FPL and Siemens follow established industry standards during the original generator rewind in 2012?

A. Yes. FPL and Siemens followed the established industry standards for insulation testing from the Institute of Electrical and Electronics Engineers (IEEE Standard 95 "IEEE Recommended Practice for Insulation Testing of AC Electric Machinery (2300V and above) with High Direct Voltage"). They also followed the established industry standards for insulation for acceptance testing, which is used to ensure equipment is operating as designed, from the American National Standards Institute (ANSI C50.10 – 1990 "Rotating Electrical Machinery – Synchronous Machines") during the original generator rewind. Additionally, contract requirements with Siemens for quality assurance were imposed in accordance with industry standard. These included expectations for inspection, testing, packaging, shipping, nonconformance process, customer communication and facilities access for mutually agreed upon witness points.

Q. Did FPL perform an extent of condition review on St. Lucie Unit 2?

A. Yes. FPL performed an extent of condition review of the Unit 2 generator maintenance history and determined a similar ground fault was not present.

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

A. FPL moved quickly to restore the unit to service safely and was able to keep the outage to approximately 57 days. Notably, the Siemens generator rewind was conducted safely and more quickly than any similar unscheduled work across the industry. Additionally, while the unit was offline, FPL was able to complete some work originally planned for the fall 2019 refueling outage, thereby reducing the fall 2019 planned outage duration by approximately two days.

Q. Has FPL filed an insurance claim for the reimbursement of costs incurred as a result of this event?

A. FPL has filed an insurance claim with Nuclear Electric Insurance Limited ("NEIL") for costs related to the full generator rewind that was performed during this outage. This claim does not include replacement fuel costs, however, because NEIL only covers replacement fuel costs when an outage surpasses 12 weeks.

Q. Please describe the circumstances related to the grid disturbance that impacted Turkey Point Unit 3.

A. A transmission line contractor that performed work on a 230 kV transmission line near Turkey Point inadvertently left personal protection grounds installed after completing the job. When the transmission line was switched back into service, a bolted three phase fault was introduced to the grid, which caused a momentary under-voltage condition on the Turkey Point units. This caused the main turbine control valve ("TCV") closure circuit and all TCVs on Unit 3 to close. The plant equipment responded as designed.

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

A. FPL reset the signal to the equipment that caused the TCVs to close before restarting the unit. Additionally, FPL modified the time delay setpoint of the Main TCV closure circuit on Unit 3 to a greater value to minimize the response to a grid disturbance.

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

A. The Unit 3 outage due to the grid disturbance was approximately one day.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20190001-EI

MARCH 15, 2019

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 employed and in what capacity?

A. I am employed by Florida Power & Light Company ("FPL"), as Business Services Director 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 2013, I have also overseen the preparation and filing of the Generating Performance Incentive Factor ("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 2018 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 2018, and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the result of these calculations: $17,151,736 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 $8,577,071.

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 +3.758, $17,151,736 in fuel savings and a GPIF reward of $8,577,071. 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 2018 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, four 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 91.3%, compared to its target of 85.0%. This results in +10.0 points, which corresponds to a GPIF reward of $1,958,256.

St. Lucie Unit 2 operated at an adjusted actual EAF of 88.9%, compared to its target of 85.1%. This results in +10.0 points, which corresponds to a GPIF reward of $1,620,469.

Turkey Point Unit 3 operated at an adjusted actual EAF of 88.5% compared to its target of 82.1%. This results in +10.0 points, which corresponds to a GPIF reward of $1,558,845.

Turkey Point Unit 4 operated at an adjusted actual EAF of 100.0% compared to its target of 93.6%. This results in +10.0 points, which corresponds to a GPIF reward of $1,798,492.

In total, the nuclear units' EAF performance results in a GPIF reward of $6,936,062.

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

A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,450 Btu/kWh compared to its target of 10,441 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 10,265 Btu/kWh compared to its target of 10,303 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The Turkey Point Unit 3 adjusted actual ANOHR is 10,936 Btu/kWh compared to its target of 11,044 Btu/kWh. This ANOHR is better than the ±75 Btu/kWh dead band around the projected target. This results in +2.84 points, which corresponds to a GPIF reward of $101,793.

Turkey Point Unit 4 adjusted actual ANOHR is 10,935 Btu/kWh compared to its target of 10,970 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

In total, the nuclear units' heat rate performance results in a GPIF reward of $101,793.

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

A. $7,037,855.

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 as shown on Exhibit CRR-1, page 5, resulting in a combined reward of $2,492,325. The other three performed worse than their availability targets as shown on Exhibit CRR-1, page 5, resulting in a combined penalty of $1,018,385. This results in a net GPIF reward of $1,473,940.

Regarding ANOHR, four 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. Another three operated below the dead band so they received a combined reward of $1,585,321 and one unit operated above the dead band so it received a penalty of $1,520,045. Thus, the total fossil units' heat rate performance results in a net GPIF reward of $65,276.

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

A. The net GPIF fossil availability performance reward of $1,473,940 plus the net GPIF heat rate fossil performance reward of $65,276 results in a total GPIF reward for FPL's fossil units of $1,539,216.

Q. To recap, what is the total GPIF result for the period January through December 2018?

A. The total GPIF result for the period January through December 2018 is $17,151,736 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 $8,577,071.

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. 20190001-EI

SEPTEMBER 3, 2019

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 Director 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 2020.

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 2020 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 2020 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 2020, FPL projects a weighted system equivalent planned outage factor ("EPOF") of 6.5% and a weighted system equivalent unplanned outage factor ("EUOF") of 8.4%, which yield a weighted system EAF target of 85.1%. The targets for this period reflect planned refuelings for St. Lucie Unit 2 and Turkey Point Units 3 and 4. FPL also projects a weighted system ANOHR target of 7,164 Btu/kWh for the period January through December 2020. 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 2020. 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 2020 represent the top 82.6% of the total forecasted system net generation for this period excluding the Okeechobee Clean Energy Center. This unit came into service in April 2019 and was excluded from the GPIF calculation because there is insufficient historical data to include it. Consistent with the GPIF Manual, this unit will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2020 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.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF LIZ FUENTES

DOCKET NO. 20190001-EI

SEPTEMBER 3, 2019

Q. Please state your name and business address.

A. My name is Liz Fuentes, and my business address is Florida Power & Light Company, 4200 West Flagler Street, Miami, Florida, 33131.

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 most regulatory accounting activities for FPL and its subsidiaries. In this role, I ensure that the Company's financial books and records comply with multi-jurisdictional regulatory accounting requirements and regulations.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Florida in 1999 with a Bachelor of Science Degree in Accounting. That same year, I was employed by FPL. During my tenure at the Company, I have held various accounting and regulatory positions of increasing responsibility with the majority of my career focused in regulatory accounting and the calculation of revenue requirements. Specifically, I have provided accounting support in multiple FPL retail base rate filings and other regulatory dockets filed at the Florida Public Service Commission ("FPSC") as well as the Federal Energy Regulatory Commission, and managed the accounting for FPL's cost recovery clauses. Also, I managed the preparation, review and filing of FPL's monthly Earnings Surveillance Reports ("ESR") at the FPSC. I am a Certified Public Accountant ("CPA") licensed in the Commonwealth of Virginia and am a member of the American Institute of CPAs. I have previously filed testimony before the Commission, most recently for the Solar Base Rate Adjustments ("SoBRAs") related to the solar photovoltaic projects placed in service in 2018, Docket No. 20170001-EI.

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 SoBRA related to the solar photovoltaic projects expected to be placed in service in 2020 (the "2020 Project"), which 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 base 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"). In addition, I will explain the appropriate regulatory treatment for investment tax credits ("ITC") associated with the 2020 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). I will also provide the final jurisdictional revenue requirements for the SoBRA approved by the Commission in Order No. PSC-2018-0028-FOF-EI, Docket No. 20180001-EI, and placed into service on January 1, 2018 (the "2017 Project").

Q. Please summarize your testimony.

A. The incremental jurisdictional revenue requirement for the first 12-months of operations related to the 2020 Project is $50.5 million. This calculation is largely based on the estimated capital expenditures presented by FPL witness William F. Brannen in his direct testimony filed on March 1, 2019.

The final annualized jurisdictional revenue requirement calculation for the 2017 SoBRA is $57.4 million. This results in a decrease in revenue requirements for the 2017 SoBRA of $3.2 million when compared to the estimate originally approved.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- LF-1 – 2020 SoBRA Revenue Requirement Calculation; and
- LF-2 – 2017 SoBRA Final Revenue Requirement Calculation

Q. Please briefly describe the basis for the 2020 SoBRA revenue requirement calculation.

A. Pursuant to the 2016 Settlement Agreement, FPL is authorized to recover the incremental jurisdictional revenue requirement based on the first 12-months of operations of the 2020 Project. If approved, the 2020 SoBRA is expected to be implemented on May 1, 2020.

Q. Did FPL calculate its 2020 SoBRA revenue requirement consistent with the revenue requirements for SoBRAs previously approved by this Commission?

A. Yes. The 2020 SoBRA revenue requirement is calculated consistent with the methodology approved by the Commission in Order Nos. PSC-2018-0028-FOF-EI and PSC-2018-0610-FOF-EI.

Q. What is the revenue requirement for the 2020 SoBRA?

A. As reflected on page 1 of Exhibit LF-1, the amount of FPL's requested base revenue increase for the first 12-months of operations of the 2020 Project is $50.5 million.

Q. Please describe the inputs utilized to compute the revenue requirement for the 2020 SoBRA.

A. The revenue requirement computations for each of FPL's SoBRAs, including the 2020 SoBRA, are based on the following inputs:

- <u>Capital expenditures</u>: These are based on the Company's estimated capital expenditures, including accumulated funds used during construction for each site. FPL witness Brannen describes the capital costs for the Project in his direct testimony filed on March 1, 2019.
- <u>Depreciation rates</u>: 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 2020 Project, FPL calculated the debt and equity ratios using Schedule 4, Page 1 of 2, of FPL's May 2019 ESR and utilized the long term debt cost rate reflected on the same referenced page. FPL also incorporated an estimate for unamortized ITCs. This approach to incremental cost of capital is the same as what was approved by the Commission for FPL's previous SoBRAs. The incremental cost of capital calculation for the 2020 Project is reflected on Page 3 of Exhibit LF-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 previous SoBRAs. The ADIT for the 2020 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. The ADIT proration adjustment for the 2020 Project is reflected on Page 5 of Exhibit LF-1.

Q. Please describe the ITCs associated with the revenue requirement calculation for the 2020 SoBRA.

A. In accordance with Section 48 of the IRC, the Company will record an ITC of approximately $100.1 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 LF-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 ESR for investments that have produced ITCs. Furthermore, it is also consistent with the FPL's previous SoBRA revenue requirement calculations approved by the Commission in Order Nos. PSC-2018-0028-FOF-EI and PSC-2018-0610-FOF-EI.

Q. What is the amount of FPL's final jurisdictional annualized revenue requirement associated with the 2017 SoBRA?

A. As reflected on page 1 of Exhibit LF-2, the final jurisdictional annualized revenue requirement associated with the 2017 SoBRA is $57.4 million.

Q. Please describe the inputs utilized to compute the final revenue requirement for the 2017 SoBRA.

A. The final revenue requirement computation for the 2017 SoBRA is based on the same inputs used for the initial 2017 SoBRA Factor included in my testimony filed on August 24, 2017, Docket No. 20170001-EI, and approved by this Commission in Order No. PSC-2018-0028-FOF-EI, except for capital costs. As reflected on page 2 of Exhibit LF-2, the projected total per book capital costs of $418.8 million used in the initial 2017 SoBRA Factor were replaced with the actual total per book costs of $395.3 million, resulting in a decrease in revenue requirements of $3.2 million from the initial 2017 SoBRA calculation. The refund calculation associated with this decrease in revenue requirements is discussed in FPL witness Edward J. Anderson's testimony.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF WILLIAM F. BRANNEN

DOCKET NO. 20190001-EI

MARCH 1, 2019

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 3,376 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 eighteen of FPL's universal solar energy centers. The total capacity of these centers is approximately 1,228 MW, which is made up of one 75 MW solar thermal facility and approximately 1,153 MW of PV generation at seventeen 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 2,200 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, which are currently under construction and expected to begin commercial operation by April 30, 2020

(“2020 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 2020 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 2020 Project -- $1,378/$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 title to each exhibit is 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 2020 Solar Energy Centers
Exhibit WFB-4	Specifications for 2020 Solar Energy Centers
Exhibit WFB-5	Property Delineations, Features and Land Use of 2020 Solar Energy Centers
Exhibit WFB-6	Construction Schedule for 2020 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 seventeen universal solar centers totaling approximately 1,153 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 building universal solar PV.

A. The seventeen PV universal solar energy centers constructed and placed into operation by FPL were completed an average of 29 days early, at a total cost of $1.85 billion, about 4.6% or nearly $90 million below the cumulative budget. In addition, each center was completed at or 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 earlier than traditional detection methods, which 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 prevents problems before they would otherwise occur resulting in improved 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, in 2017 FPL established a Renewable Operations Control Center ("ROCC") to serve 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 the 2020 Project.

A. FPL will place four solar energy centers in service by May 1, 2020. These are the Hibiscus Solar Energy Center in Palm Beach County, the Okeechobee Solar Energy Center in Okeechobee County, the Southfork Solar Energy Center in

Manatee County, and the Echo River Solar Energy Center in Suwannee County. Each center will have a nameplate capacity of 74.5 MW_{AC}. Exhibits WFB-2, WFB-3, WFB-4 and WFB-5 more fully describe and depict the centers.

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

A. 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. Both 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 2020 Project will utilize a combination of approximately 550,000 silicon crystal and 566,000 thin-film solar PV panels that convert sunlight to direct current ("DC") electricity. These panels will have an average conversion efficiency of approximately 18.6%. This simply means that 18.6% of the solar energy reaching the surface of the panels is converted into DC electrical energy. The average efficiency of the panels that will be used on the 2020 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, 2018, and 2019 solar projects.

The panels will be mounted on fixed-tilt support structures at the Okeechobee and Hibiscus centers and on tracking support structures at the Echo River and

Southfork centers. The panels 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. The inverters are paired with a single medium voltage transformer on a common equipment skid to form a power conversion unit ("PCU"). Twenty-four PCUs are required to produce a capacity of 74.5 MW_{AC} at the Okeechobee center, with twenty-three PCUs at the Hibiscus center, and twenty-two for the remaining two centers. These configurations will produce the same output at all centers. Exhibit WFB-2 provides a typical block diagram depicting the basic layout of major equipment components.

Q. Describe the DC/AC ratio for the 2020 Project.

A. The DC/AC ratio is the ratio of the total installed DC capacity of PV modules to the AC capacity of each energy center. The DC/AC ratios for the energy centers that comprise the 2020 Project will range from 1.45 to 1.50 depending on design considerations and site features unique to each of the centers.

Q. Why are the DC/AC ratios not the same for all the centers?

A. Design optimization activities and the careful selection of major components determines a DC/AC ratio for each center that yields high levels of output, availability, reliability, and the highest overall benefit to customers. Site and equipment characteristics unique to each of the centers drives variability in the DC/AC ratios. Ongoing design optimization efforts may yield DC/AC ratios different from those mentioned earlier, but only to the extent such changes result in a greater overall benefit to FPL's customers.

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 three of the four centers – Hibiscus, Southfork and Echo River – are similar, although the specific details vary from center to center based on which scheme will provide the lowest cost option for each site. New collection substations with step-up power transformers will be constructed for each of these three 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 these centers range from 115 kV to 230 kV. The new collection substations for these three centers will be connected to the bulk transmission system by looping the existing transmission line into a new transmission switchyard that shares a common site with the collection substation. The looped transmission lines are all less than one tenth of a mile.

The fourth center, Okeechobee, will connect indirectly to the FPL transmission system through the Okeechobee Clean Energy Center ("OCEC"). A new step-down transformer will decrease the AC collection system voltage from 34.5 kV to 26 kV, which is the operating voltage of the low side of the step-up transformer for one of the Okeechobee combustion turbine generators, which subsequently connects to the FPL 500 kV transmission system.

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 projected cost for its unique interconnection configuration.

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. Did FPL have to acquire property for the energy centers?

A. Yes, FPL acquired property for three of the four energy centers. FPL was able to use land at the OCEC site for the Okeechobee Solar Energy Center.

Q. Can you explain how FPL acquired and optimized the property for the centers?

A. Yes. FPL identified candidate parcels available for purchase for the three centers through a review of real estate listings and public land records. FPL screened the list of candidate parcels by using criteria including each property's proximity to a transmission system interconnection point and whether the property provides sufficient acreage to accommodate the expected 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 2020 Project?

A. As I noted earlier, it is expected that the Project will be placed into service by May 1, 2020. The period necessary to complete engineering, permitting, equipment procurement, contractor selection, construction, and commissioning will exceed twenty-two months. This construction period includes the time necessary to prepare each of the sites, construct roads and drainage systems, install the solar generating equipment, erect 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 1, 2019, 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 required approval from the U.S. Army Corps of Engineers. All such permits have been issued. Finally, applications for the required county zoning, special exceptions, and site plan approvals have been submitted and all four sites have received all county level approvals.

Q. What is FPL's estimated cost for the 2020 Project?

A. FPL estimates the cost of the 2020 Project will be $410.7 million or $1,378/kW$_{AC}$. The cost of each center ranges from $1,339/kW$_{AC}$ to $1,407/kW$_{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 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 99.5% of all the surveying, engineering, equipment, materials and construction services necessary to complete the centers were established through competitive bidding processes specific to the 2020 Project. The balance of the costs was the result of leveraging existing agreements for engineering services, which themselves were the result of a separate competitive bidding process. Therefore, 100% of the Project's costs were subject to competitive solicitations.

Q. Please describe the competitive solicitations associated with the 2020 Project.

A. Throughout 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 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 nineteen large, industry-leading suppliers. All nineteen suppliers submitted proposals that satisfied the requirements of the request for proposals and all were evaluated. Due to the volume of panels required for the 2020 Project and availability of supply in the market, 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 nine PCU suppliers. Two of the suppliers elected not to submit proposals. The proposals submitted by the seven remaining suppliers met the requirements of the request for proposals and were evaluated. FPL selected the lowest cost bidder to supply the PCUs.

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

Engineering, procurement, and construction ("EPC") proposals for the Project's solar fields were solicited from seven industry-recognized contractors. Four of the contractors elected not to submit proposals. The bids submitted by the three remaining contractors met the requirements of the request for proposals. Accordingly, these submitted proposals were evaluated. In mid-December 2018, FPL executed a contract with the EPC contractor that submitted the lowest and most competitive proposal for the construction of the 2020 Project.

Proposals for the construction of the substation and interconnection facilities were solicited from sixteen industry-recognized contractors. Ten contractors did not submit bids. The remaining six bids satisfied the requirements of the request for proposal and were evaluated. The two lowest cost bidders have been selected to construct the substation and interconnection facilities. Each will be constructing facilities at two sites.

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

Q. Are there other benefits associated with the 2020 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 2020 Project compare to the cost of FPL's 2017, 2018 and 2019 Projects?

A. The estimated cost for FPL's 2017, 2018, and 2019 Projects were $1,405/kW_{AC}$, $1,485/kW_{AC}$, and $1,386/kW_{AC}$ respectively. At $1,378/kWac the estimated cost of the 2020 Project is lower than the estimated costs for the 2017, 2018, and 2019 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 2020 Project is well below the prescribed cost cap, and the competitive bidding process provides assurance that costs for equipment, engineering, and construction for the 2020 Project are reasonable as previously discussed. The construction schedule for the Project also is reasonable.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF JUAN E. ENJAMIO

DOCKET NO. 20190001-EI

MARCH 1, 2019

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 at FPL, I have held positions as a Transmission System Planner, Power System Control Center Engineer, Bulk Power Markets Engineer, Supervisor of Transmission Planning, Supervisor of Supply and Demand Analysis, and 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)

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

A. The purpose of my testimony is to present FPL's 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 2020 (the "2020 Project"), is cost-effective. My testimony covers several areas. First, I briefly describe the 2020 Project. FPL's witness Brannen provides a more detailed description in his testimony. 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 projected to be 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 May 1, 2020. FPL performed an economic analysis and determined that the 2020 Project is projected to result in a reduction in the cumulative present value of revenue requirements ("CPVRR") to FPL customers, for a total savings of approximately $26 million. In addition, these centers are also 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 2020 Project is projected to be 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 2020 Project.

A. The 2020 Project comprises four centers with a total nameplate capacity of 298 MW_{AC}, which will be constructed and is expected to be placed in service by May 1, 2020. On average, these centers will have a capacity factor of 28.7% and generate 190,000 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 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 December 2018. This load forecast, including system peaks and net energy for load, will be used in FPL's 2019 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 December 2018. This fuel price forecast will be used in FPL's 2019 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 November 2018. ICF is a consulting firm with extensive experience in forecasting the cost of complying with the regulation 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 2026, will be used in preparing FPL's 2019 TYSP. FPL has utilized ICF's CO_2 emission price forecast in preparing its resource plans since 2007, including the economic analyses presented in the need determination dockets for the Okeechobee Clean Energy Center (Docket No. 150196-EI) and Dania Beach Clean Energy Center

(Docket No. 20170225-EI), previous SoBRA filings (Docket Nos. 20170001-EI and 20180001-EI), and the Nuclear Cost Recovery proceedings (e.g., Docket Nos. 20150009-EI and 20160009-EI).

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. In the first resource plan, called the "No 2020 Project Plan," no new solar facilities are assumed beyond the 2019 SoBRA Project except the solar facilities that will comprise FPL's voluntary shared solar program.[1] In this resource plan, future resource needs are met by batteries, combustion turbines, and combined cycle units.

The second resource plan, called the "2020 Project Plan," adds the 2020 Project. As a result of adding the 2020 Project, a 100 MW battery in 2020 is no longer needed.

These two resource plans are shown in Exhibit JE-3.

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

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[1] FPL will separately file a petition detailing its proposed voluntary shared solar program, which will be known as *SolarTogether - An FPL Shared Solar Program* ("FPL SolarTogether"). This program will consist of 1,490 MW of solar generation. The first FPL SolarTogether project is expected to be placed in service in the first quarter of 2020, and the remaining FPL SolarTogether projects are expected to be placed in service in the fourth quarter of 2020 and the first quarter of 2021.

A. Firm capacity value is based on the expected output of a solar facility at the time of summer peak load, which typically occurs 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 of its solar PV facilities, existing or new.

The 2020 centers are projected to have an average summer firm capacity value of 61% of their nameplate rating. Therefore, the four centers, with a total nameplate capacity of 298 $MW_{AC,}$ are assumed to have a total firm capacity of 182 MW_{AC} at the time of summer peak. These solar installations are assumed to have zero firm capacity value at the 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 2020 Project.

A. FPL used the hourly production costing model UPLAN to forecast the system economics and compare resource plans that include or exclude the 2020 Project. This model has been used by FPL in prior proceedings at the Commission including each of its previous petitions for SoBRA approval. 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 2020 Project Plan" from the CPVRR of the "2020 Project Plan". As shown in Exhibit JE-4, the CPVRR benefit to FPL customers from the 2020 Project is projected to be approximately $26 million.

Q. Will the 2020 Project reduce FPL's use of fossil fuel?

A. Yes. The 2020 Project is expected to reduce the annual average use of natural gas by 4,734 million cubic feet, and the use of coal by 459 tons. By adding the 2020 Project to its generation fleet, FPL reduces its reliance on these fossil fuels.

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

A. Reducing the use of fossil fuel is projected to result in an average annual reduction of 281,000 tons of global warming gases, specifically CO_2. This reduction in CO_2 is equivalent to removing approximately 54,000 cars from the road. Sulfur dioxide and nitrogen oxide emissions are projected to be reduced by an annual average of 1 ton and 29 tons, respectively.

Q. What is your conclusion regarding the 2020 Project?

A. As demonstrated by the economic analysis described in my testimony, the addition of the 2020 Project is projected to result in CPVRR savings of approximately $26 million. Therefore, the 2020 Project meets the SoBRA cost-effectiveness requirement established in the 2016 FPL Rate Case Settlement. Additionally, the 2020 Project is projected to 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.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF EDWARD J. ANDERSON

DOCKET NO. 20190001-EI

SEPTEMBER 3, 2019

Q. Please state your name and business address.

A. My name is Edward J. Anderson, 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 Manager-Regulatory Rate Development.

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

A. I am responsible for developing the appropriate rate design for FPL's customers and for administration of the Company's electric rates and charges.

Q. Please describe your educational background and professional experience.

A. I graduated from the Virginia Military Institute in 2002 with a Bachelor of Arts in Economics and Business. In November 2016, I joined FPL as Principal Analyst in the Rate Development section of the Regulatory Affairs business unit, and assumed my current role in March 2018. Prior to joining FPL, I was employed by Dominion Energy for fourteen years. From 2003 to 2007, I worked within Dominion's Trading and Marketing Organization as a

Business Operations Support Associate and Power Market Analyst. My responsibilities included Power Pool (PJM and NE-ISO) reconciliation, analysis, and trading support. In 2007, I was promoted to Hourly Trader where I was responsible for managing and optimizing the hourly operations of Dominion's merchant power plant assets in PJM and NE-ISO. From 2008 to 2016, I worked within Dominion's State Regulation Department as a senior level Regulatory Pricing Analyst and Regulatory Advisor. My responsibilities included providing support and analysis as they related to rate design for all base and rider regulatory filings and was the Company's rates witness for several generation adjustment and fuel rate proceedings.

I have previously presented testimony before the State Corporation of Virginia and the North Carolina Utilities Commission on rate design matters.

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 May 1, 2020 ("2020 Project"). I am also presenting the revision to FPL's SoBRA Factor which became effective on January 1, 2018 (the "2017 Project") and the corresponding prospective true-up rates to become effective January 1, 2020, and the amount to be refunded through the Capacity Cost Recovery Clause ("CCRC") as a result of the true-up.

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:

- EJA-1 2020 SoBRA Factor Calculation;
- EJA-2 Projected Retail Base Revenues for May 1, 2020;
- EJA-3 Summary of Tariff Changes for May 1, 2020;
- EJA-4 Revised 2017 SoBRA Factor;
- EJA-5 2017 Project Refund Calculation;
- EJA-6 2017 SoBRA Prospective Adjustment for January 1, 2020;
- EJA-7 Projected Retail Base Revenues for January 1, 2020;
- EJA-8 Summary of Tariff Changes for January 1, 2020; and
- EJA-9 Typical Bill Projections.

2020 SoBRA Factor

Q. Please explain the calculation of the 2020 SoBRA factor and the purpose it serves.

A. I have calculated the 2020 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 requirement of $50.491 million presented by FPL witness Liz Fuentes for the 2020 Project and (2) the forecasted retail base revenue from electricity sales for the first twelve months of operations, expected to begin May 1, 2020.

Application of the SoBRA factor to the Company's May 1, 2020 base rates will provide the Company with sufficient revenue to recover the costs associated with the construction and operation of the 2020 Project. The calculation and resulting SoBRA factor of 0.732% is shown in Exhibit EJA-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 May 1, 2020?

A. Yes. Exhibit EJA-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 May 1, 2020. 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. 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. Additionally, retail base revenues have been adjusted prospectively to account for the true-up associated with FPL's 2017 SoBRA. The total adjusted retail base revenues from the sale of electricity for the twelve months beginning May 1, 2020 are projected to be $6,896.706 million, shown on Exhibit EJA-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 May 1, 2020?**

A. Yes. Exhibit EJA-3 provides a summary of the base rates proposed to become effective for meter readings made on and after May 1, 2020, shown in column 4 of Exhibit EJA-3, pages 1-25. If the SoBRA and the associated charges are approved for the 2020 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 2020 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. **Will customers receive a credit if the actual capital expenditures for the 2020 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 CCRC 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 refund associated with FPL's 2017 SoBRA, which I will describe.

2017 SoBRATrue-Up

Q. **You mentioned previously that you are also presenting the revision to FPL's SoBRA Factor for the true-up of the 2017 Project revenue requirements. Please explain.**

A. We are employing the identical mechanism FPL employed to true-up the capital expenditures associated with the Cape Canaveral and Port Everglades Energy Centers. As presented in Exhibit LF-2 to the testimony of FPL witness Fuentes, the 2017 Project's revised jurisdictional annualized base revenue requirement based on actual capital costs is $57.371 million.

Except for the revenue requirement associated with the actual capital costs, the revised SoBRA Factor is computed using the same data used in the computation of the initial SoBRA Factor. This data includes billed retail base revenues from the sales of electricity and unbilled retail base revenues in the amount of $6,458.109 million, as was described in the testimony of FPL witness Tiffany C. Cohen supporting the initial 2017 SoBRA .

The revised 2017 SoBRA Factor using the updated revenue requirement of $57.371 million is 0.888%. The computation of the revised SoBRA Factors is provided in Exhibit EJA-4, page 1 of 1.

Q. Please describe the refund associated with FPL's 2017 Project.

A. Pursuant to the Settlement Agreement and consistent with the Initial SoBRA Filing, once the 2017 Project actual capital costs are known, if the unit's actual capital costs are less than the projected costs used to develop the initial SoBRA Factors, a one-time credit is to be made through the CCRC. The difference between the cumulative base revenues that have been collected since the implementation of the initial SoBRA Factor on January 1, 2018 and the cumulative base revenues that would have resulted if the revised SoBRA Factors had been implemented on January 1, 2018 will be credited to customers through the CCRC with interest through December 31, 2019 at the 30-day commercial paper rate as specified in Rule 25-6.109. The amount of the refund with interest for 2017 Project since the project entered commercial service is $6.658 million and is shown on Exhibit EJA-5, page 2 of 2.

Q. Will rates need to be adjusted going forward to account for the 2017 SoBRA true-up?

A. Yes, in accordance with Section 10(g) of the Settlement Agreement, base rates will also be adjusted to reflect the revised SoBRA factor effective January 1, 2020 to account for this revision in jurisdictional revenue requirements going forward. Exhibits EJA-6 through EJA-8 present the calculations and resulting rates for this change.

<u>Bill Impacts</u>

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

A. Exhibit EJA-9 provides projected bill changes. The typical bill projections reflect proposed base and clause changes to become effective on January 1, 2020 and proposed base and fuel changes related to the SoBRA for the 2020 Project scheduled to become effective by May 1, 2020.

FPL projects that the May 2020 typical residential bill of $96.71 will remain 30% below the national average (as of January 2019), 17% below the state average (as of June 2019), and will remain among the lowest in the state of Florida.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20190001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2018 Final True-Up)
on behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis Young, 1635 Meathe Road, West Palm Beach, Florida 33411.

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 2018 through December 2018.

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 over recovery of $2,475,441.

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 2018 period and the total true-up amount to be collected or refunded during the January - December 2019 period.

Q. What was the actual end of period true-up amount for January - December 2018?

A. For the Consolidated Electric Division it was $1,482,331 under recovery. We have included in this computation a refund to our customers of $2,181,243 in federal tax savings. If not for these savings, the actual end of period true-up would be a $3,663,574 under-recovery. The resulting final remaining true-up amount without the federal tax saving benefits would have been reduced to an over-recovery of $294,198.

Q. What was the Commission-approved amount to be collected or refunded during the January – December 2019 period?

A. A consolidated under-recovery of $3,957,772 to be collected.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20190001-EI: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Direct Testimony of Curtis D. Young (Estimated/Actual)

On Behalf of Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Curtis D. Young. My business address is 1635 Meathe Drive, West Palm Beach, Florida 33411.

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 have a Bachelor of Business Administration Degree in Accounting from Pace University in New York City, New York. 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. 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 this docket.

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

A. I am attaching Schedules E1-A, E1-B, and E1-B1 as part of Composite Prehearing Identification Number CDY-2. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2019 – December 2019 based on 6 Months Actual and 6 Months Estimated data.

Q. Were these schedules completed by you or under your direct supervision?

A. The schedules were completed under my direct supervision.

Q. What was the final remaining true-up amount for the period January 2018 – December 2018?

A. The final remaining true-up amount was an over-recovery of $2,475,441.

Q. What is the estimated true-up amount for the period January 2019 – December 2019?

A. The estimated true-up amount is an under-recovery of $4,409,893.

Q. What is the total true-up amount estimated to be collected, or refunded for the period January 2020 – December 2020?

A. At the end of December 2019, based on six months actual and six months estimated, the Company estimates it will under-recover $1,934,452 in purchased power costs, which will be collected from January 2020 – December 2020.

Q. Has the Company made any revisions to its 2019 estimated six month projection data?

A. Yes, there are a few factors that have changed since our original projection filing for 2019. We've updated the cost rates pertaining to fuel purchases from Gulf Power for our Northwest division and FPL for our Northeast division, which were originally based on rates that were available at that time. Therefore, we have updated our fuel costs to more accurately reflect current billing data from our power suppliers. Also, we have revised our monthly estimated KWH sales data to agree with our most current budget forecasts.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20190001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2020 Projection Testimony of Michelle D. Napier

On Behalf of

Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Michelle D. Napier. My business address is 1635 Meathe Drive, West Palm Beach, FL 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company") as Manager of Regulatory Affairs.

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

A. I received a Bachelor of Science degree in Finance from the University of South Florida in 1986. I have been employed with FPUC since 1987. During my employment at FPUC, I have performed various roles and functions in accounting, including General Accounting Manager before moving to the Regulatory department in 2011. I am currently the Manager of Regulatory Affairs. In this role, my responsibilities include directing the regulatory activities for FPUC. This includes regulatory analysis and filings before the Florida Public Service Commission (FPSC) for FPUC, FPUC-Indiantown, FPUC-Fort Meade, Florida

Division of Chesapeake Utilities (CFG) and Peninsula Pipeline Company.

Q. Have you previously testified in this Docket?

A. No.

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

A. My testimony will establish the "true-up" collection amount, based on actual January 2018 through June 2019 data and projected July 2019 through December 2020 data to be collected or refunded during January 2020 – December 2020. My testimony will also summarize the computations that are contained in composite exhibit MDN-1 supporting the January through December 2020 projected levelized fuel adjustment factors for its consolidated electric divisions.

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 MDN-1, 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, 20180001-EI and 20190001-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 2019 true-up for Florida Public Utilities Company?

A. Florida Public Utilities engaged Sterling Energy Services, LLC. ("Sterling") Christensen Associates Energy, LLC ("Christensen"), Locke Lord, LLP ("Lord"), and Pierpont and McClelland ("Pierpont") for assistance in the development and enactment of projects/programs designed to reduce their purchased power rates to its customers. The associated legal and consulting costs, included in the rate calculation of the Company's 2020 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. Christensen also assisted the Company with analysis regarding the purchase power agreements.

Q. What are the final remaining true-up amounts for the period January – December 2018 for both Divisions?

A. The final remaining consolidated true-up amount was an over-recovery of $2,475,441.

Q. What are the estimated true-up amounts for the period of January – December 2019?

A. There is an estimated consolidated under-recovery of $4,409,893.

Q. Please address the calculation of the total true-up amount to be collected or refunded during the January - December 2020 year?

A. The Company has determined that at the end of December 2019, based on six months actual and six months estimated, we will have a consolidated electric under-recovery of $1,934,452.

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 5.109¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2020 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 MDN-1, a residential customer using 1,000 KWH will pay $131.46. This is a decrease of $5.17 below the previous period.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20190001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2020 Projection Testimony of Michelle D. Napier (Amended)

On Behalf of

Florida Public Utilities Company

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

A. My name is Michelle D. Napier. My business address is 1635 Meathe Drive, West Palm Beach, FL 33411.

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

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company") as Manager of Regulatory Affairs.

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

A. I received a Bachelor of Science degree in Finance from the University of South Florida in 1986. I have been employed with FPUC since 1987. During my employment at FPUC, I have performed various roles and functions in accounting, including General Accounting Manager before moving to the Regulatory department in 2011. I am currently the Manager of Regulatory Affairs. In this role, my responsibilities include directing the regulatory activities for FPUC. This includes regulatory analysis and filings before the Florida Public Service Commission (FPSC) for FPUC, FPUC-Indiantown, FPUC-Fort Meade, Florida

Division of Chesapeake Utilities (CFG) and Peninsula Pipeline Company.

Q. Have you previously testified in this Docket?

A. No.

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

A. My testimony will establish the "true-up" collection amount, based on actual January 2018 through June 2019 data and projected July 2019 through December 2020 data to be collected or refunded during January 2020 – December 2020. My testimony will also summarize the computations that are contained in composite exhibit MDN-1 supporting the January through December 2020 projected levelized fuel adjustment factors for its consolidated electric divisions.

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 MDN-1, 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, 20180001-EI and 20190001-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 2019 true-up for Florida Public Utilities Company?

A. Florida Public Utilities engaged Sterling Energy Services, LLC. ("Sterling") Christensen Associates Energy, LLC ("Christensen"), Locke Lord, LLP ("Lord"), and Pierpont and McClelland ("Pierpont") for assistance in the development and enactment of projects/programs designed to reduce their purchased power rates to its customers. The associated legal and consulting costs, included in the rate calculation of the Company's 2020 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. Christensen also assisted the Company with analysis regarding the purchase power agreements.

Q. What are the final remaining true-up amounts for the period January – December 2018 for both Divisions?

A. The final remaining consolidated true-up amount was an over-recovery of $2,475,441.

Q. What are the estimated true-up amounts for the period of January – December 2019?

A. There is an estimated consolidated under-recovery of $4,409,893.

Q. Please address the calculation of the total true-up amount to be collected or refunded during the January - December 2020 year?

A. The Company has determined that at the end of December 2019, based on six months actual and six months estimated, we will have a consolidated electric under-recovery of $1,934,452.

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 5.109¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2020 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 Revised Schedule E-10 in Composite Exhibit Number MDN-1, a residential customer using 1,000 KWH will pay a fuel charge of $74.59 in 2020. The 2019 fuel charge for the same KWH is $95.26. Therefore, proposed fuel costs decrease by $20.67, or $21.20 with gross receipts taxes included. I should add that the total proposed bill on the Revised Schedule E-10 of $115.24 is based upon FPUC's current base rates, and excludes the Company's requested increase to recover costs associated with restoration of its facilities following Hurricane Michael. If the projection were to assume approval of the requested increase, as well as the other adjustments to the Company's conservation cost recovery factor and gross receipts taxes, the net monthly bill for a residential customer using 1,000 KWH would be

$131.46, a net decrease of $4.98 on a typical customer's bill.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 20190001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2020 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. 20180001-EI, the Commission's regular fuel cost recovery proceeding, and also provided both pre-filed and live testimony the prior year, in Docket No. 20170001-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, execution of new purchased power agreements with Florida Power & Light ("FPL"), generation supply located on Amelia Island and investigation into the opportunities of energy provided from solar and battery installations.

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

A. The Company regularly pursues opportunities to achieve energy resiliency and reduced purchased power costs for the benefit of our customers. During 2018, we began by executing a transmission interconnection agreement and a new purchased power agreement with Florida Power & Light (FPL) in our Northeast Florida Division. The most recent significant opportunity in 2019 came to fruition with the completion of a new purchased power agreement with FPL for our Northwest Florida Division and the amendment of the existing FPL purchased power agreement for our Northeast Florida Division. .

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

A. The existing agreement for our Northwest Florida Division with Gulf Power is effective through December 31, 2019. The existing agreement for our Northeast Florida Division with FPL is effective through the December 31, 2024 expiration date.

Q. **Can you provide background on the new purchased power agreement with FPL for the Northwest Florida Division and the amendment of the purchased power agreement for the Northeast Florida Division that will become effective January 1, 2020?**

A. Yes. Informal solicitations occurred with four providers that were capable of providing wholesale power to the Northwest Florida Division delivery points located in Jackson and Calhoun Counties. Additional consideration was given to the ability to combine agreements for the Northeast and Northwest Florida Divisions in order to provide additional flexibility, reduced cost and energy resiliency between divisions. Proposals were received from four parties and the evaluation and discussions began immediately thereafter. Based on the differences in the bids submitted, the evaluation 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 that impacted both the Northwest and Northeast Florida Divisions. On August 12, 2019 the "Native Load Firm All Requirements Power and Energy Agreement" ("Agreement") for the Northwest Florida Division was executed by both parties with an effective date of January 1, 2020 and continuing in effect through December 31, 2026. Additionally, on August 12, 2019, the "First Amendment To The Native Load Firm All Requirements Power and Energy Agreement" ("Amendment") for the Northeast Florida Division was executed by both parties. The "Amendment" will have the effect of extending the existing agreement for the Northeast Florida Division through December 31, 2026. Both the "Agreement" and "Amendment" include a provision that will allow FPUC the sole right to extend the agreements through December 31, 2030.

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 increased energy resiliency and 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" and "Amendment" with FPL, the already quantifiable benefits of the existing project 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 actively involved in the initial development and engineering of a new project located on Amelia Island. Although this project is still in the early stages, early indications are that the project would be feasible and would provide benefits to all parties involved.

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

A. Yes. FPUC has completed the analysis related to smaller PV systems within the FPUC electric service territory. Based on the results from the analysis, the economic feasibility of smaller PV installations has been difficult to achieve due to many different factors. At this time, 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. The "Agreement" and the "Amendment" have provisions that allow for the development of PV installations by FPUC and provides for the possibility of a partnership between the parties that would allow for the development of a PV project.

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.

(Whereupon, prefiled direct testimony was inserted.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony
C. Shane Boyett
Docket No. 20190001-EI
Date of Filing: March 1, 2019

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Regulatory Issues Manager for Gulf Power Company (Gulf or the Company).

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

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

Q. What is the purpose of your testimony in this docket?
A. The purpose of my testimony is to present the final true-up amounts for the period January 2018 through December 2018 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will summarize Gulf Power Company's fuel expenses, net power transaction expense, purchased power capacity costs, and certify that these expenses were properly incurred during the period January 2018 through December 2018. Lastly, I will present the actual benchmark level for the calendar year 2019 gains on non-separated wholesale energy sales eligible for a shareholder incentive and the amount of gains or losses from hedging settlements for the period January 2018 through December 2018.

Q. Have you prepared any exhibits to which you will refer in your testimony?
A. Yes, I am sponsoring 2 exhibits. Exhibit 1 consists of 8 schedules and includes 2 schedules which relate to the fuel and purchased power cost recovery final true-up, 1 schedule that relates to Gulf's natural gas fuel hedging activities for 2018 and 5 schedules that relate to the capacity cost recovery final true-up. Exhibit 2 contains Schedules A-1 through A-9 and A-12 for the period December 2018, previously filed with the Florida Public Service Commission (FPSC or Commission).

Counsel: We ask that Mr. Boyett's exhibits be marked as Exhibit No. _____(CSB-1) and ______(CSB-2).

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have. Unless otherwise indicated, the actual data in these documents is taken from the books and records of Gulf Power Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by the Commission. Based on the information in these documents and the foregoing testimony, the recoverable fuel and purchased power costs, and hedging activities are reasonable and prudent.

I. FUEL

Q. Which schedules of your exhibit relate to the calculation of the fuel and purchased power cost recovery true-up amount?

A. Schedules 1 and 2 of my Exhibit CSB-1 relate to the fuel and purchased power cost recovery true-up calculation for the period January 2018 through December 2018. These schedules compare twelve months of actual data to the revised actual/estimated true-up filed in last year's fuel docket which included seven months of actual and five months of re-projected data. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for December 2018 are incorporated herein as Exhibit CSB-2. The A-schedules compare twelve months of actual data to twelve months of projected data from a combination of the original 2018 fuel projection for the period January through June, and the 2018 estimated true-up re-projections for the period July through December.

Q. What is the final fuel and purchased power cost true-up amount related to the period January 2018 through December 2018 to be addressed through the fuel cost recovery factors in the period January 2020 through December 2020?

A. A net over-recovery amount of $4,512,071, to be returned to customers, was calculated as shown on Schedule 1 of my Exhibit CSB-1.

Q. How was this amount calculated?

A. The $4,512,071 is calculated on Schedule 1 of my Exhibit CSB-1 by taking the difference between the estimated and actual over/under-recovery amounts for the period January 2018 through December 2018. The estimated over-recovery amount was $13,195,558 as compared to the actual over-recovery amount of $17,707,628, resulting in an over-recovery of $4,512,071. The estimated true-up amount for this period was approved in FPSC Order No. PSC-2018-0610-FOF-EI, dated December 26, 2018.

Q. What are the primary factors which contributed to the final fuel and purchased power cost true-up amount?

A. Gulf Power experienced slightly higher than estimated fuel and net power expense which was more than offset by higher than estimated jurisdictional fuel clause revenue. These variances are discussed in more detail below and are summarized on Schedule 2 of my Exhibit CSB-1.

Fuel Clause Revenue

Q. Please explain the variance in Fuel Revenue Applicable for 2018.

A. Gulf Power's jurisdictional fuel revenue was $350,111,657 which was $8,400,269 or 2.46% above the estimated/actual. This variance is due to jurisdictional energy sales being 152,524 MWH or 1.3% higher than estimated.

Total Fuel and Net Power Transactions

Q. During the period January 2018 through December 2018, how did Gulf Power Company's recoverable total fuel and net power transaction expenses compare with the actual/estimated expenses?

A. Gulf's recoverable total fuel cost and net power transaction expense was $384,657,932 which is $3,509,807 or 0.92% above the estimated amount of $381,148,125. Actual fuel and net power transaction energy was 11,782,999 MWh compared to the estimated net energy of 11,886,406 MWh or 0.87% below the estimated amount. The slightly higher total fuel and net power transaction expense is attributed to higher than estimated amount of coal and natural gas generation costs offset by an increase in energy power sales revenue driven by a higher than estimated reimbursement rate for the year. This information is summarized on Schedule 2 of my Exhibit CSB-1.

Total Fuel Cost of Generated Power

Q. During the period January 2018 through December 2018, how did Gulf Power Company's recoverable fuel cost of net generation compare with the actual/estimated expenses?

A. Gulf's recoverable fuel cost of system net generation was $291,564,766 or 7.17% above the estimated amount of $272,054,316. Actual generation was 9,320,038 MWh or 0.30% below the estimated generation of 9,348,372 MWh. The resulting actual average fuel cost of 3.128 cents per kWh was 7.50% above the estimated fuel cost of 2.910 cents per kWh. The actual quantity of fuel consumed was 85,957,268 MMBtu which is 3.89% above the estimated quantity of 82,737,320 MMBtu. The weighted average fuel cost for natural gas was 2.92 cents per kWh, which is 0.23 cents per kWh or 8.55% above the estimated 2.69 cents per kWh. The weighted average fuel cost for coal, plus lighter fuel, was 3.14 cents per kWh, which is 1.29% higher than the estimated cost of 3.10 cents per kWh. The higher total fuel expense is attributed to the quantity of kWh generated for coal combined with higher than estimated natural gas prices for the period. This information is summarized on Schedule 2 of my Exhibit CSB-1.

Total Cost of Purchased Power

Q. During the period January 2018 through December 2018, how did Gulf Power Company's recoverable fuel cost of purchased power compare to actual/estimated cost?

A. Gulf's recoverable fuel cost of purchased power for the period was $211,899,427 or 3.61% above the estimated amount of $204,517,999. Total megawatt hours of purchased power were 6,432,547 MWh compared to the estimate of 6,464,902 MWh or 0.50% below estimates. The resulting average fuel cost of purchased power was 3.294 cents per kWh or 4.13% above the estimated amount of 3.164 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2018 included in my Exhibit CSB-2 and summarized on schedule 2 of Exhibit CSB-1.

Q. What are the reasons for the difference between Gulf's actual fuel cost of purchased power and the actual/estimated costs?

A. The higher total fuel cost of purchased power is primarily due to higher than estimated prices for natural gas-fired energy supplied to Gulf Power through power purchase agreements.

<u>Power Sales</u>

Q. During the period January 2018 through December 2018 how did Gulf Power Company's recoverable fuel cost of power sold compare with the actual/estimated costs?

A. Gulf's recoverable fuel cost of power sold for the period is $123,204,069 or 18.92% above the estimated amount of $103,604,582. The total quantity of power sales was 3,701,704 MWh compared to Gulf's estimated sales of 3,668,716 MWh, or 0.90% above estimates. The resulting average fuel cost of power sold was 3.328 cents per kWh or 17.86% above the estimated amount of 2.824 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2018 and summarized on Schedule 2 of CSB-1.

Q. What are the reasons for the difference between Gulf's actual fuel cost of power sold and the actual/estimated costs?

A. The overall quantity of MWH sales was 0.90% higher than estimated amounts, however, the higher total credit to fuel expense is attributed to a higher than estimated reimbursement rate (cents per kWh) due to higher than estimated prices for natural gas throughout the period.

Gains on Non-Separated Wholesale Energy Sales Benchmark

Q. Has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2018 gains?

A. Yes, the three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2016 through 2018 is calculated as follows:

Year	Actual Gain
2016	700,065
2017	1,988,936
2018	589,410
Three-Year Average	$ 1,092,804

Q. What is the actual threshold for 2019?
A. The actual threshold for 2019 is $1,092,804.

II. HEDGING

Q. Did Gulf's fuel hedging activity during 2018 follow Gulf Power's Risk Management Plan for Fuel Procurement?
A. Yes. As part of the Stipulation and Settlement Agreement, in Docket No. 20160186-EI, Gulf agreed to continue its existing moratorium for new natural gas financial hedges until January 1, 2021. Although Gulf did not enter into any new financial hedge contracts in 2018, hedges that settled in 2018 were entered into prior to the current moratorium on natural gas financial hedges and complied with previously approved Risk Management Plans.

Q. For the period in question, what volume of natural gas was hedged using a fixed price contract or financial instrument?
A. Gulf Power hedged 17,040,000 MMBtu of natural gas in 2018 using financial instruments. This represents 29% of Gulf's 59,533,727 MMBtu of actual gas burn during the period, which includes gas burn for the Central Alabama PPA combined cycle unit. The total amount of natural gas burn by month is reported on Schedule 3 of Exhibit CSB-1.

Q. What types of hedging instruments were used by Gulf Power Company, and what type and volume of fuel was hedged by each type of instrument?
A. Natural gas was hedged using financial swap contracts that were entered into prior to the current moratorium to fix the price of natural gas to a certain price. These swaps settled against either a NYMEX Last Day price or Gas Daily price. Of the volume of gas hedged for the period, all was hedged using financial swap contracts.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument for the period January 2018 through December 2018?
A. No fees, commissions, or premiums were paid by Gulf on the financial hedge transactions during this period. Gulf's 2018 hedging program activities for the period January through December 2018 resulted in a net hedge settlement cost of $11,832,300, as shown on line 2 of the December 2018 Schedule A-1, period-to-date of my Exhibit CSB-2.

III. PURCHASED POWER CAPACITY

Q. Mr. Boyett, you stated earlier that you are responsible for the purchased power capacity cost recovery true-up calculation. Which schedules of your exhibit relate to the calculation of this amount?
A. Schedules 4, CCA-1, CCA-2, CCA-3, and CCA-4 of Exhibit CSB-1 relate to the purchased power capacity cost recovery true-up calculation for the

period January 2018 through December 2018. Schedules CCA-1 and Schedule 4 summarize the calculation of the final true-up amount. Schedules CCA-2 through CCA-4 provides the monthly calculation of the actual over/under-recovery of purchased power capacity costs, monthly calculation of the interest provision and additional details related to purchased power capacity contracts which also appear on Lines 1 and 2 of Schedule CCA-2. In addition, Schedule A-12 of my Exhibit CSB-2 contains purchased power capacity cost information for the period January 2018 through December 2018.

Q. What is the final purchased power capacity cost true-up amount related to the period of January 2018 through December 2018 to be addressed in the period January 2020 through December 2020?

A. An over-recovery amount of $384,798 should be returned to customers through 2020 purchased power capacity clause rates as shown on Schedule CCA-1 of Exhibit CSB-1.

Q. How was this amount calculated?

A. The $384,798 was calculated by taking the difference between the estimated January 2018 through December 2018 over-recovery of $1,187,593 and the actual over-recovery of $1,572,391, which is the sum of lines 11, 12, and 15 under column 1 of Schedule 4 of Exhibit CSB-1. The estimated true-up amount for this period was approved in FPSC Order No. PSC-2018-0610-FOF-EI dated December 26, 2018.

Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed July 27, 2018.

Q. During the period January 2018 through December 2018, how did Gulf's actual total purchased power capacity costs and jurisdictional capacity clause revenue compare with the actual/estimated amounts?

A. The actual total capacity payments for the period January 2018 through December 2018, as shown on line 5 of Schedule 4 contained in my Exhibit CSB-1, was $76,438,831. Gulf's total estimated net purchased power capacity cost for the same period was $76,317,948, as indicated on line 5 of Schedule CCE-1B of my Exhibit CSB-2 filed July 27, 2018 in Docket No. 20180001-EI. The difference between the actual net capacity cost and the estimated net capacity cost for the recovery period is $120,882 or 0.2% more than the estimated amount. Jurisdictional capacity clause revenue for the period January 2018 through December 2018, as shown on line 10 of Schedule 4, was $75,855,715, or $495,714 higher than the estimate of $75,360,001. Jurisdictional capacity clause revenue and expenses were essentially on budget with variances less than one percent for the period.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. Shane Boyett
Docket No. 20190001-EI
July 26, 2019

Q. Please state your name and business address.

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520. I am the Regulatory, Forecasting and Pricing Manager for Gulf Power Company (Gulf or the Company).

Q. Have you previously filed testimony in this docket?

A. Yes, I provided direct testimony on March 1, 2019.

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

A. The purpose of my testimony is to present the estimated true-up amounts for the period January 2019 through December 2019 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will also compare Gulf Power Company's original projected fuel and net power transaction expense and purchased power capacity costs with current estimated/actual costs for the period January 2019 through December 2019 and summarize any variances in these areas. The current actual and estimated costs consist of actual expenses for the period January 2019 through June 2019 and projected costs for July 2019 through December 2019.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?
A. Yes, I am sponsoring two exhibits. My first exhibit consists of 16 schedules that relate to the fuel and purchased power capacity estimated true-up schedules. My second exhibit contains the calculation of the purchased power capacity credit provision related to Scherer wholesale revenue (Scherer/Flint Credit) contained in the Stipulation and Settlement Agreement that resolved consolidated Docket Nos. 20160186-EI and 20160170-EI.

Counsel: We ask that Mr. Boyett's exhibits be marked as Exhibit Nos. ____ (CSB-3) and ____ (CSB-4).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period January 2019 through December 2019, the Purchased Power Capacity Cost estimated true-up calculations for the period January 2019 through December 2019 and the Scherer/Flint Credit calculations as set forth in your exhibits?
A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?
A. Yes, I have. The actual data in these documents is taken from the books and records of Gulf Power Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by the Commission.

I. FUEL COST RECOVERY CLAUSE

Q. Mr. Boyett, what has Gulf calculated as the fuel cost recovery true-up factor to be applied in the period January 2020 through December 2020?

A. The fuel cost recovery true-up factor for this period is 0.0061 cents per kWh. As shown on Schedule E-1A, this calculation includes an estimated under-recovery for the January through December 2019 period of $5,178,904. It also includes a final over-recovery for the January through December 2018 period of $4,512,071 (see Schedule 1 of Exhibit CSB-1 filed in this docket on March 1, 2019). The resulting total under-recovery of $666,834 will be incorporated into Gulf's proposed 2020 fuel cost recovery factors.

Q. Please explain the variances on Schedule E-1B-1.

A. Below is an explanation of key areas of Schedule E-1B-1 of my Exhibit CSB-3.

<u>Total Fuel and Net Power Transactions (Schedule E-1B-1, line 13)</u>

Gulf's currently projected recoverable total fuel and net power transactions cost for the period is $376,284,806, which is $6,985,117, or 1.89% higher than the original projected amount of $369,299,689. The higher total fuel and net power transactions cost for the period is attributed to higher fuel cost of generated power together with lower than expected revenue from power sales, partially offset by lower purchased power expense. The resulting average per unit fuel and net power transactions cost is estimated to be 3.1828 cents per kWh, or 0.50% higher than the original projection of 3.1670 cents per kWh.

Total Cost of Generated Power (Schedule E-1B-1, line 4)

Gulf's currently projected recoverable total fuel cost of generated power for the twelve months ending December 2019 is $274,733,590, which is $14,381,006, or 5.52% above the original projected amount of $260,352,584. Total generation is expected to be 8,918,709 MWh compared to the original projected generation of 8,760,506 MWh, or 1.81% above original projections. The resulting average fuel cost is expected to be 3.0804 cents per kWh, or 3.65% above the original projected amount of 2.9719 cents per kWh.

The total fuel cost of system net generation for the first six months of 2019 was $114,355,513, which is $2,172,991, or 1.94% higher than the projected cost of $112,182,522. On a fuel cost per kWh basis, the actual cost was 3.18 cents per kWh, which is 10.80% higher than the projected cost of 2.87 cents per kWh. This higher than projected average cost of system generation was due to a lower than projected mix of lower-cost gas-fired generation for the period. This information is found on Schedule A-3, Period to Date, of the June 2019 Monthly Fuel Filing.

The total cost of coal burned (including boiler lighter) for the first six months of 2019 was $68,126,785, which is $12,206,086, or 21.83% higher than the projection of $55,920,699. Total coal-fired generation was 1,910,740 MWh, which is 12.31% higher than the projection of 1,701,275 MWh for the period. On a fuel cost per kWh basis, the actual cost was 3.57 cents per kWh, which is 8.51% higher than the projected cost of 3.29 cents per kWh. The higher per kWh cost of coal-fired generation is due to actual coal prices (including boiler lighter) being 10.77% higher than projected on a $/MMBtu basis, partially offset by the weighted average heat rate (Btu/kWh) of the coal-fired generating units that operated performing 2.18% better than projected. This information is found on Schedule A-3, Period to Date, of the June 2019 Monthly Fuel Filing.

The total cost of natural gas burned for generation for the first six months of 2019 was $43,690,454, which is $10,279,178, or 19.05% lower than Gulf's projection of $53,969,632. The total gas-fired generation was 1,608,317 MWh, which is 24.38% lower than the projection of 2,126,802 MWh for the period. Gulf's gas-fired generating units consumed 11,022,160 MMBtu, or 23.33% less than the projected amount of 14,375,396 MMBtu during the period. On a cost per unit basis, the actual cost of gas-fired generation was 2.72 cents per kWh, which is 7.09% higher than the projected cost of 2.54 cents per kWh. The lower than projected total cost of natural gas is due to lower gas-fired generation(MWH). This information is found on Schedule A-3, Period to Date, of the June 2019 Monthly Fuel Filing.

Total Fuel Cost and Gains on Power Sales (Schedule E-1B-1, line 12)

Gulf's currently projected recoverable fuel cost and gains on power sales for the twelve months ending December 2019 are $101,489,520, or 3.58%

lower the original projected amount of $105,253,229. Total power sales are expected to be 4,212,573 MWh, in comparison to the original projection of 4,417,871 MWh, or 4.65% below projections. The currently projected price for the fuel cost and gains on power sales is 2.4092 cents per kWh, which is 1.12% higher than the original projection of 2.3824 cents per kWh.

The total fuel cost of power sold for the first six months of 2019 was $31,092,839, which is $10,866,948, or 25.90% lower than the projection of $41,959,786. The quantity of power sales for the period was 33.75% lower than projected. The actual cost was 2.5244 cents per kWh, which is 11.85% above the projected cost of 2.2570 cents per kWh. The lower than projected total power sales during the period is due to lower than projected quantities of sales for the period. This information is found on Schedule A-1, Period to Date, line 12 of the June 2019 Monthly Fuel Filing.

<u>Total Cost of Purchased Power (Schedule E-1B-1, line 7)</u>

Gulf's currently projected recoverable fuel cost of purchased power for the twelve months ending December 2019 is $203,040,737, or 5.21% below the original projected amount of $214,200,334. The total amount of purchased power is expected to be 7,116,310 MWh, in comparison to the original projection of 7,318,073 MWh, or 2.76% below projections. The resulting average fuel cost of purchased power is expected to be 2.8532 cents per kWh, or 2.52% below the original projected amount of 2.9270 cents per kWh. The lower total fuel cost of purchased power is attributed to lower than projected quantities of purchased power for the period.

The total fuel cost of purchased power for the first six months of 2019 was $99,213,477, which is $5,593,307, or 5.34% lower than the original projection of $104,806,784. The quantity of purchased power for the period was 238,209 MWh, or 6.75% lower than the original projection. The lower than projected purchased power expense is due to lower quantities of purchases made during the first half of 2019. On an average cost per kWh basis, the actual cost was 3.0168 cents per kWh, which is 1.52% higher than the projected cost of 2.9716 cents per kWh. This information is found on Schedule A-1, Period to Date, line 7 of the June 2019 Monthly Fuel Filing. A majority of Gulf's purchases are from energy or power purchase agreements (PPAs), which include contracts associated with a gas-fired generating unit and multiple renewable energy purchase agreements.

II. HEDGING

Q. Please briefly discuss the status of Gulf's hedging program.

A. There has been no change in the status of Gulf's hedging program. Gulf's hedging program is currently subject to a moratorium pursuant to the Joint Stipulation and Agreement for Interim Resolution of Hedging Issues filed on October 24, 2016, in Docket No. 20160001-EI and approved by the Commission in Order No. PSC-16-0547-FOF-EI. Subsequently, on March 20, 2017, Gulf filed a Stipulation and Settlement Agreement which resolved all issues in consolidated Docket Nos. 20160186-EI and 20160170-EI. As part of the Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-17-0178-S-FOF-EI, the existing moratorium for new natural gas financial hedges shall continue until January 1, 2021. Accordingly, Gulf has not entered into any new financial natural gas hedges since the effective date of the stipulated moratorium.

Q. For the period January 2019 through June 2019, what volume of natural gas was hedged using a fixed price contract or instrument?

A. Under previously-approved Risk Management Plans, Gulf Power financially hedged 2,700,000 MMBtu of natural gas for the period. This equates to 10% of the 26,638,836 MMBtu actual natural gas burn for Plant Smith Unit 3 and the Central Alabama PPA.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price. The swaps settled against the monthly NYMEX settlement price. The total amount of gas hedged for the period was hedged using financial swaps.

Q. What was the actual total cost (e.g., fees, commission, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. No fees, commission, or option premiums were incurred. Gulf's gas hedging program generated hedging settlement costs of $2,878,590 for the period January through June 2019. This information is found on Schedule A-1, Period to Date, line 1a of the June 2019 Monthly Fuel Filing.

III. PURCHASED POWER CAPACITY

Q. Mr. Boyett, you stated earlier that you are responsible for the Purchased Power Capacity Cost (PPCC) true-up calculation. Which schedules of your Exhibit CSB-3 relate to the calculation of these factors?

A. Schedules CCE-1A, CCE-1B, CCE-2, CCE-3 and CCE-4 of my Exhibit CSB-3 relate to the Purchased Power Capacity Cost true-up calculation.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2020 through December 2020?

A. The true-up for this period is 0.0022 cents per kWh, as shown on Schedule CCE-1A. This calculation includes an estimated under-recovery of $622,746 for January 2019 through December 2019. It also includes a final over-recovery of $384,798 for the period January 2018 through December 2018 (see Schedule CCA-1 of Exhibit CSB-1 filed in this docket on March 1, 2019). The resulting total under-recovery of $237,948 will be incorporated into Gulf Power's proposed 2020 purchased power capacity cost recovery factors.

Q. During the period January 2019 through December 2019, what is Gulf's projection of purchased power capacity costs and how does it compare with the original projection of capacity costs?

A. As shown on Schedule CCE-1B, lines 1 and 2, of Exhibit CSB-3, Gulf's total capacity payments projection for the January 2019 through December 2019 recovery period is $86,178,359. Gulf's original projection for the period was $86,048,498 and is shown on lines 1 and 2 of Schedule CCE-1 filed August 24, 2018. Gulf's capacity payments were on budget at 0.15%, or $129,861 higher than the original projection. Actual capacity costs during the first six months of 2019 were $43,198,381 (Lines 1 & 2 of Schedule CCE-1B), which is $129,678 higher than projected amount of $43,068,703 for the period (from Lines 1 & 2 of Schedule CCE-1 filed August 24, 2018).

Q. Please describe how the Stipulation and Settlement Agreement in consolidated Docket Nos. 20160186-EI and 20160170-EI is applied to the Capacity Clause as it relates to the portion of Gulf's ownership of Scherer Unit 3 that is still committed to a wholesale customer.

A. I have prepared Exhibit CSB-4 to present the calculation of Flint Electric Membership Corporation (Flint) wholesale contract revenue that was committed to retail customers pursuant to the relevant provisions of the approved Stipulation and Settlement agreement. The credit that is included in the PPCC is equal to total Flint revenue less the environmental cost recovery revenue requirements and fuel costs attributable to the portion of Scherer Unit 3 that is currently contracted to Flint through December 2019. The total estimated Scherer/Flint credit for 2019 is

$8,722,800. The estimated Scherer/Flint Credit for the period January through December 2019, as shown on line 4 of Schedule CCE-1B of Exhibit CSB-3, has the effect of lowering retail capacity payments (line 5). The calculation of the credit, as presented in Exhibit CSB-4, is performed in accordance with the Stipulation and Settlement Agreement approved by Order No. PSC-17-0178-S-EI in the consolidated Docket Nos. 20160186-EI and 20160170-EI.

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

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. Shane Boyett
Docket No. 20190001-EI
Date of Filing: September 3, 2019

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520. I am the Regulatory, Forecasting and Pricing Manager for Gulf Power Company.

Q. Have you previously filed testimony before the Florida Public Service Commission (FPSC or Commission) in Docket No. 20190001-EI?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the projection of fuel expenses, net power transaction expense, and purchased power capacity costs for the period January 2020, through December 2020. I will also present the resulting calculation of Gulf Power's fuel cost recovery and purchased power capacity factors for the period January 2020 through December 2020.

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

A. Yes. I have three separate exhibits I am sponsoring as part of this testimony as shown below.

Exhibit Number	Summary
CSB-5	23 schedules related to Fuel and Purchased Power Capacity Calculations
CSB-6	Gulf Power Company's Hedging Information Report filed with the Commission Clerk on April 3, 2019, and assigned Document Numbers DN 03491-2019 (redacted) and 03495-2019 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for August 2018 through December 2018 in compliance with Order No. PSC-08-0316-PAA-EI.
CSB-7	Gulf Power Company's Hedging Information Report filed with the Commission Clerk on August 9, 2019, and assigned Document Numbers DN 07298-2019 (redacted) and DN 07334-2019 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for January 2019 through July 2019 in compliance with Order No. PSC-08-0316-PAA-EI.

Counsel: We ask that Mr. Boyett's exhibits as described be marked for identification as Exhibit Nos. _____(CSB-5), _____(CSB-6), and _____(CSB-7).

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

I. FUEL

Q. Please explain the calculation of the fuel and purchased power expense true-up amount included in the levelized fuel factor for the period January 2020 through December 2020.

A. As shown on Schedule E-1A of Exhibit CSB-5, the total true-up amount of $666,834 includes an estimated under-recovery for the January 2019 through December 2019 period of $5,178,904, in addition to a final over-recovery for the period January 2018 through December 2018 of $4,512,071. The estimated under-recovery for the January 2019 through December 2019 period includes six months of actual data and six months of estimated data as reflected on Schedule E-1B of Exhibit CSB-5.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2018 through December 2018?
A. The GPIF result shown on Line 26 of Schedule E-1 is an increase of 0.0001 cents per kWh to the levelized fuel factor, thereby rewarding Gulf $10,384.

Q. Has Gulf Power accounted for and returned all tax reform savings resulting from the Tax Cuts and Jobs Act of 2017 and related Stipulation and Settlement Agreements?
A. Yes. Each of the respective provisions of the Stipulation and Settlement Agreements approved by this Commission through issuance of Order Nos. PSC-2018-0180-FOF-EI and PSC-2018-0548-S-EI in Docket No. 20180039-EI were implemented through fuel cost recovery rates spanning the period April 2018 through December 2019. There are no additional tax savings to be included in prospective fuel cost recovery rates.

Q. What is the appropriate revenue tax factor to be applied in calculating the levelized fuel factor?
A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs, as shown on Line 24 of Schedule E-1.

Q. What is the levelized projected fuel factor for the period January 2020 through December 2020?

A. Gulf has proposed a levelized fuel factor of 3.244 cents per kWh. This factor is based on projected fuel and purchased power energy expenses and projected kWh sales for January 2020 through December 2020 and includes the true-up and GPIF amounts identified above.

Q. Mr. Boyett, how were the line loss multipliers used on Schedule E-1E calculated?

A. The line loss multipliers were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest MWh Load Flow Allocators.

Q. Mr. Boyett, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, and OS-III?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 3.262 cents per kWh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. Mr. Boyett, how were the time-of-use fuel factors calculated?

A. The time-of-use fuel factors were calculated based on projected loads and system lambdas for the period January 2020 through December 2020 and include the GPIF and true-up amount. These time-of-use fuel factors as shown on Schedule E-1E have all been adjusted for line losses.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2019, and how would the change affect the cost of 1,000 kWh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2019 is 3.047 cents per kWh compared with the proposed factor of 3.262 cents per kWh. For a residential customer who is billed for 1,000 kWh in January 2020, the fuel portion of the bill would increase from $30.47 to $32.62.

Q. Has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my exhibit. These costs represent the estimated averages for the period from January 2020 through December 2020. In addition, pursuant to Commission Order No. PSC-16-0119-TRF-EG in Docket No. 150248-EG, Gulf has calculated the bill credit for participants of the Community Solar Pilot Program to be $1.68 per month based on the 2020 projected solar-weighted average annual avoided energy cost of 2.7 cents per kWh.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2020 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-PAA-EI, an estimated three-year average benchmark level has been calculated as follows:

2017 actual gains	1,988,936
2018 actual gains	589,410
2019 estimated gains	123,369
Three-Year Average	$900,572

This amount represents the minimum projected threshold for 2020 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100% of the gains on non-separated sales for 2020.

Total Fuel and Net Power Transactions

Q. What is Gulf's projected recoverable total fuel and net power transactions cost for the January 2020 through December 2020 recovery period?

A. Gulf's projected total fuel and net power transactions cost for the period is $353,910,537 as shown on Schedule E-1 line 15 of Exhibit CSB-5.

Q. How does the total projected fuel and net power transactions cost for the 2020 period compare to the updated projection of fuel cost for the same period in 2019?

A. The total updated cost of fuel and net power transactions for 2019, reflected on Schedule E-1B-1 line 13 of Exhibit CSB-3 filed in this docket on July 26, 2019, is projected to be $376,284,806. The projected total cost of fuel and net power transactions for the 2020 period reflects a decrease of $22,374,269 or 5.95% lower than the same period in 2019. On a fuel cost per kWh basis, the 2019 projected cost is 3.1828 cents per kWh, and the 2020 projected fuel cost is 3.0700 cents per kWh, a decrease of 0.1128 cents per kWh or 3.54%.

<u>Total Cost of Generated Power</u>

Q. What is Gulf's projected recoverable total fuel cost of generated power for the period?

A. The projected total cost of fuel to meet system generated power needs in 2020 as shown in Exhibit CSB-5, Schedule E-1, line 4 is $266,767,756.

Q. How does the projected total fuel cost of generated power for the 2020 period compare to the updated projection of fuel cost for the same period in 2019?

A. The total updated cost of fuel to meet 2019 system generated power needs, reflected on Schedule E-1B-1, line 4 of CSB-3 filed in this docket on July 26, 2019, is projected to be $274,733,590. The projected total cost of fuel to meet system net generation needs for the 2020 period reflects a decrease of $7,965,834 or 2.90% less than the same period in 2019. Total system net generation in 2020 is projected to be 9,374,344 MWh, which is 455,635 MWh or 5.11% higher than projected for 2019. The lower projected total fuel expense is primarily the result of lower estimated hedging settlement costs for the period as Gulf's hedge ratio approaches zero in the first quarter of 2020 and fuel savings related to the addition of Gulf's first utility-scale solar project going into service in January 2020. On a fuel cost per kWh basis, the 2019 projected cost is 3.0804 cents per kWh, and the 2020 projected fuel cost is 2.8457 cents per kWh, a decrease of 0.2347 cents per kWh or 7.62%.

Weighted average coal burned price including boiler lighter fuel for 2019 as reflected on Schedule E-3, line 32 of my Exhibit CSB-3 filed in this docket on July 26, 2019, is projected to be $3.03 per MMBtu. Weighted average coal burned price including boiler lighter fuel for 2020, as reflected on Schedule E-3, line 34 is projected to be $3.00 per MMBtu. These figures reflect a cost decrease of $0.03 per MMBtu or 0.99%. The weighted average natural gas price for 2019, as reflected on Schedule E-3, line 33 of the exhibit to my testimony filed in this docket on July 26, 2019, is projected to be $3.57 per MMBtu. The weighted average natural gas price for 2020, as reflected on Schedule E-3, line 35 is projected to be $3.39 per MMBtu. This is a decrease in price of $0.18 per MMBtu or 5.04%.

As reflected on Schedule E-3, lines 42 and 43, the projected fuel cost of Gulf's coal-fired generation is 3.28 cents per kWh, and the projected fuel cost of Gulf's gas-fired generation is 2.68 cents per kWh for the 2020 period.

Fuel Cost and Gains on Power Sales

Q. What are Gulf's projected recoverable fuel cost and gains on power sales for the 2020 period?

A. Gulf's projected recoverable fuel cost and gains on power sales is $129,226,624 as shown on Schedule E-1, line 13.

Q. How does the total projected recoverable fuel cost and gains on power sales for the 2020 period compare to the projected recoverable fuel cost and gains on power sales for the same period in 2019?

A. The total updated recoverable fuel cost and gains on power sales in 2019, reflected on Schedule E-1B-1, line 12 of my exhibit filed in this docket on July 26, 2019, is projected to be $101,489,520. The projected recoverable fuel cost and gains on power sales in 2020 represents an increase of $27,737,104 or 27.33%. Total quantity of power sales in 2020 is projected to be 5,407,380 MWh, which is 1,194,807 MWh or 28.36% higher than currently projected for 2019. On a fuel cost per kWh basis, the 2019 projected cost is 2.4092 cents per kWh, and the 2020 projected fuel cost is 2.3898 cents per kWh, which is a decrease of 0.0194 cents per kWh or 0.81%. The higher total credit to fuel expense from power sales is attributed to a higher projected quantity of power sales from units operating to meet incremental system loads.

Total Cost of Purchased Power

Q. What is Gulf's projected total cost of purchased power for the period?

A. Gulf's projected recoverable cost for energy purchases is $216,369,405 as shown on Schedule E-1, line 8.

Q. How does the total projected purchased power cost for the 2020 period compare to the projected purchased power cost for the same period in 2019?

A. The total updated cost of purchased power to meet 2019 system needs, reflected on Schedule E-1B-1, line 7 of my testimony filed in this docket on July 26, 2019, is projected to be $203,040,737. The projected cost of purchased power to meet system needs in 2020 is an increase of $13,328,668 or 6.56% higher than currently projected for 2019. The total quantity of purchased power in 2020 is projected to be 7,560,995 MWh, which is 444,685 MWh or 6.25% higher than is currently projected for 2019. On a fuel cost per kWh basis, the 2019 projected cost is 2.8532 cents per kWh, and the 2020 projected fuel cost is 2.8617 cents per kWh, which represents an increase of 0.0085 cents per kWh or 0.30%. The higher total cost of purchased power is attributed to a higher projected quantity of purchased power energy to meet system loads.

II. FUEL PROCUREMENT

Q. Does the 2020 projection of fuel cost of net generation reflect any major changes in Gulf's fuel procurement program for this period?

A. No. There have been no major changes in Gulf's fuel procurement program for the 2020 period. Gulf Power's coal requirements are purchased in the market through the Request for Proposal (RFP) process that has been used for many years. Natural gas requirements will be purchased from various suppliers using firm quantity agreements with market pricing for base needs and on the daily spot market when necessary. Natural gas transportation will be secured using a combination of firm and spot transportation agreements.

Q. What actions does Gulf take to procure natural gas and natural gas transportation for its units at competitive prices for both long-term and short-term deliveries?

A. Gulf procures natural gas using both long and short-term agreements for gas supply at market-based prices. Gulf secures gas transportation for non-peaking units using long-term agreements for firm pipeline capacity and for peaking units using interruptible transportation, released seasonal firm transportation, or delivered natural gas agreements.

III. HEDGING

Q. Has anything changed with regard to the status of Gulf's hedging program since filing testimony on July 26, 2019, in this docket?

A. There has been no change in the status of Gulf's hedging program. However, actual hedging settlement data has become available for the month of July 2019 and is included in my Exhibit CSB-7 as previously filed with this Commission on August 9, 2019.

Q. What are the results of Gulf's natural gas price hedging program for the period August 2018 through July 2019?

A. Gulf had financial hedges in place during the period to hedge the price of natural gas. These financial hedges have been effective in fixing the price of a percentage of Gulf's gas burn during the period. Between August 2018 and July 2019, Gulf recorded hedging settlement costs of $6,679,150. Pursuant to Order No. PSC-08-0316-PAA-EI, Gulf filed Hedging Information Reports with the Commission on April 3, 2019, and August 9, 2019, detailing its natural gas hedging transactions for August 2018 through July 2019. I am sponsoring these reports as Exhibits CSB-6 and CSB-7 to my testimony in this docket.

IV. PURCHASED POWER CAPACITY

Q. You stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which of your exhibits relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1A and CCE-1B, Schedule CCE-2, and Schedule CCE-4 of my Exhibit CSB-5 relate to the calculation of the PPCC recovery factors for the period January 2020 through December 2020.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 shows the calculation of jurisdictional capacity costs to be recovered through the PPCC Recovery Clause. Lines 1 through 3 show Gulf's projected net capacity expense, which includes a credit for transmission revenue. The total net projected capacity costs are applied to a jurisdictional factor and added to the total true-up which is then adjusted for revenue taxes to determine the amount to be recovered in the period through PPCC recovery factors.

Q. What jurisdictional factor was used to calculate projected recoverable capacity costs for the period January 2020 through December 2020?

A. The PPCC jurisdictional factors applied in the calculation of jurisdictional net purchased power capacity costs is 97.23427 percent, which is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C. This approach is consistent with past jurisdictional allocations in the PPCC Recovery Clause. The existing wholesale generation services agreement between Gulf Power Company and Florida Public Utilities Company (FPU) will expire on December 31, 2019, however, on August 12, 2019, Gulf Power and FPU executed a new stratified wholesale agreement that will commence on January 1, 2020, if approved. In order to implement a stratified allocation of costs between the retail and wholesale jurisdiction consistent with the new contract structure, considerable work by Gulf Power to stratify costs and derive appropriate stratified jurisdictional factors must be completed. Gulf currently estimates this work will be completed before 2020 final true-up calculations are filed with the Commission. Subject to the foregoing determination of stratified jurisdictional factors, any eventual over or under recovery of costs due to changes in jurisdictional allocations will be handled through the normal true-up process.

Q. What is the appropriate revenue tax factor to be applied in calculating the total recoverable capacity payments?

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional purchased power capacity costs, as shown on Line 10 of Schedule CCE-1.

Q. What methodology was used to allocate the capacity payments by rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology approved by the Commission in Order No. PSC 17-0178-S-EI in consolidated Docket Nos. 160186-EI and 160170-EI. This allocation is consistent with the treatment accorded to production plant in the cost of service study approved by the Commission in Gulf's most recent base rate proceeding. For purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs by rate class within the retail jurisdiction based on the 12-MCP and 1/13th energy allocator.

Q. How were the rate class allocation factors used in the PPCC Recovery Clause calculated?

A. The rate class demand allocation factors used in the PPCC Recovery Clause have been calculated using the 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C. and adjusted for losses. The rate class energy allocation factors were calculated based on projected kWh sales for the period and adjusted for losses.

The calculations of the allocation factors are shown in columns A through I on page 1 of Schedule CCE-2.

Q. Please describe the calculation of the PPCC recovery factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, 12/13th of the jurisdictional capacity cost to be recovered is allocated by rate class based on the demand allocator. The remaining 1/13th is allocated based on energy.

Gulf has calculated the PPCC factor for the LP/LPT rate classes based on kilowatt (kW) rather than kilowatt hour (kWh) in accordance with Order No. PSC-13-0670-S-EI issued December 9, 2013, in Docket No. 130140-EI. The total revenue requirement assigned to rate class LP/LPT shown in column E is then divided by the sum of the projected billing demands (kW) for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each LP/LPT customer's billing demand (kW) to calculate the amount to be billed each month.

For all other rate classes, the total revenue requirement assigned to each rate class shown in column E is then divided by that class's projected kWh sales for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each customer's total kWh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1,000 kWh?

A. The purchased power capacity costs recovered through the clause for a residential customer who is billed for 1,000 kWh will be $8.78.

Q. What is Gulf's projected recoverable capacity payments for the 2020 cost recovery period?

A. The total recoverable capacity payments for the period are $83,785,002. This amount is captured in the Schedule CCE-1, line 11. Schedule CCE-4 shows the projected cost associated with the Southern Intercompany Interchange capacity, if applicable, and any long-term purchased power contracts that are included for capacity cost recovery and lists their associated capacity amounts in megawatts. Also included in Gulf's 2020 projection of capacity cost is revenue produced by a market-based agreement between the Southern electric system operating companies and South Carolina PSA (Public Service Authority). The total capacity cost of $85,867,467 is shown on Schedule CCE-4, line 14. The total capacity costs included on Schedule CCE-4 line 14 is the sum of lines 1 and 2 of Schedule CCE-1.

Q. Have there been any new purchased power agreements entered into by Gulf that impact the total recoverable capacity payments for the period?

A. No.

Q. What other projected revenues or credits has Gulf included in its capacity cost recovery clause for the period?

A. Gulf has included an estimate of transmission revenues associated with off-system economy sales in the amount of $6,000 in its capacity cost recovery projection. This amount is captured on Schedule CCE-1, line 3 of my Exhibit CSB-5.

Q. Have there been any other notable changes to the projected recoverable capacity costs for the period January 2020 through December 2020?

A. Yes. The ratemaking adjustment I have referred to in previous testimony as the “Scherer/Flint credit” will cease at the end of December 2019 when the long-term wholesale contract with Flint EMC expires on December 31, 2019. As a result, the Scherer/Flint revenue credits associated with the Flint contract are no longer available to retail customers through reductions to the recoverable purchased power capacity cost recovery rates beginning in 2020. The end of this ratemaking treatment was contemplated by the Stipulation and Settlement Agreement approved by FPSC Order No. PSC-17-0178-S-EI.

Q. How do the total projected net jurisdictional capacity payments for the 2020 period compare to the current estimated net jurisdictional capacity payments for the same period in 2019?

A. Gulf’s 2020 Projected Jurisdictional Capacity Payments, found on Schedule CCE-1, line 7, are $83,486,772. This amount is $8,219,096 or 10.92% more than the current estimate of $75,267,676 (Schedule CCE-1B, line 7) for 2019 that was filed in my actual/estimated true-up testimony in this docket on July

26, 2019. The higher projected jurisdictional capacity payments for 2020 are attributed to the expiration of the Flint EMC wholesale agreement and resulting Scherer/Flint revenue credits which are projected to be $8,722,800 for the updated 2019 period.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?
A. The fuel and capacity recovery factors will be effective beginning with the first billing cycle in January 2020 and continuing through the last billing cycle of December 2020.

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

(Whereupon, prefiled direct testimony was inserted.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. L. Nicholson
Docket No. 20190001-EI
Date of Filing: March 15, 2019

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

A. My name is Cody L. Nicholson. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Senior Power Generation Department Technical Services Specialist for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from Auburn University in 1998. I joined Southern Company with Alabama Power in 1996 as a summer intern. Upon graduation in 1998, I joined Southern Company Services (SCS), a subsidiary of Southern Company. During my time at SCS, I worked in Farley Project and in Generating Plant Performance (GPP), where I progressed through various engineering positions with increasing responsibilities. My primary responsibility in Farley Project was to coordinate design changes to Plant Farley. My primary responsibility in GPP was to conduct heat rate tests and performance tests on plant equipment. I joined Southern Nuclear Operating Company (SNC) in 2011. At SNC, my primary responsibility was to coordinate responses to requests from the U. S. Nuclear Regulatory Commission for various projects. I joined SCS in 2014 as a Performance and Reliability Engineer, where my primary responsibility was to report key performance indicators on a monthly basis.

I joined Gulf Power in 2015 in my current job position as Senior Power Generation Department Technical Services Specialist as previously mentioned in my testimony. In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

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

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2018, through December 31, 2018.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have prepared an exhibit consisting of five schedules.

Counsel: We ask that Mr. Nicholson's Exhibit consisting of five schedules be marked as Exhibit No. _______ (CLN-1).

Q. Is there any information that has been supplied to the Commission pertaining to this GPIF period that requires amendment?

A. Yes. Some corrections have been made to the actual unit performance data, which was submitted monthly to the Commission during this time period. These corrections are based on discoveries made during the final data review to ensure the accuracy of the information reported in this filing. The actual unit performance data tables on pages 13 through 22 of

Schedule 5 of my exhibit incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

Q. Please review the Company's equivalent availability results for the period.

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 12 of Schedule 5. Pages 3 through 7 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by FPSC Order No. PSC-2018-0610-FOF-EI is on page 8 of Schedule 2. The results are: Scherer 3, -10.00 points; Crist 7, -10.00 points; Daniel 1, -10.00 points; Daniel 2, -10.00 points; and Smith 3, -10.00 points.

Q. What were the heat rate results for the period?

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 6 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on pages 7 through 11 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in September 2017, are shown on page 13 of Schedule 3. As calculated on page 14 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points:

Scherer 3, 0.00 points; Crist 7, 0.00 points; Daniel 1, 2.44 points; Daniel 2, 6.68 points, and Smith 3, 0.00 points.

Q. What number of Company points was achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was 0.02 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $10,384.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 8 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 14 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $10,384 as provided for by the GPIF plan.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
C. L. Nicholson
Docket No. 20190001-EI
Date of Filing: September 3, 2019

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

A. My name is Cody L. Nicholson. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Senior Power Generation Division Technical Services Specialist for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from Auburn University in 1998. I joined Southern Company with Alabama Power in 1996 as a summer intern. Upon graduation in 1998, I joined Southern Company Services (SCS), a subsidiary of Southern Company. During my time at SCS, I worked in the Farley Project department as well as Generating Plant Performance (GPP), where I progressed through various engineering positions with increasing responsibilities. My primary responsibility in the Farley Project was to coordinate design changes to Plant Farley. My primary responsibility in GPP was to conduct heat rate tests and performance tests on plant equipment. I joined Southern Nuclear Operating Company (SNC) in 2011. At SNC, my primary responsibility was to coordinate responses to requests from the U. S. Nuclear Regulatory Commission for various projects. I joined SCS in

2014 as a Performance and Reliability Engineer, where my primary responsibility was to report key performance indicators on a monthly basis. I joined Gulf Power in 2015 in my current job position as Senior Power Generation Division Technical Services Specialist as previously mentioned in my testimony. In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

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

A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2020 through December 31, 2020.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have prepared one exhibit entitled CLN-2 consisting of three schedules.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Counsel: We ask that Mr. Nicholson's exhibit consisting of three schedules be marked for identification as Exhibit___(CLN-2).

Q. Which units does Gulf propose to include under the GPIF for the subject period?
A. We propose that Crist Unit 7, Daniel Units 1 and 2, Smith Unit 3, and Scherer Unit 3 be included as the Company's GPIF units. The projected net generation from these units is approximately 88% of Gulf's projected net generation for 2020.

Q. For these units, what are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2020 through December 31, 2020?
A. I would like to refer you to page 26 of Schedule 1 of my exhibit where these targets are listed.

Q. How were these proposed target heat rates determined?
A. They were determined according to the GPIF Implementation Manual procedures for Gulf.

Q. Describe how the targets were determined for Gulf's proposed GPIF units.
A. Page 2 of Schedule 1 of my exhibit shows the target average net operating heat rate equations for the proposed GPIF units and pages 4 through 23 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 24 and 25 of Schedule 1 present the calculations that provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit indicated on page 26 of Schedule 1 of your exhibit calculated according to the appropriate GPIF Implementation Manual procedures?
A. Yes.

Q. What are the proposed target, maximum, and minimum equivalent availabilities for Gulf's units?
A. The target, maximum, and minimum equivalent availabilities are listed on page 4 of Schedule 2 of my exhibit.

Q. How were the target equivalent availabilities determined?
A. The target equivalent availabilities were determined according to the standard GPIF Implementation Manual procedures for Gulf and are presented on page 2 of Schedule 2 of my exhibit.

Q. How were the maximum and minimum attainable equivalent availabilities determined for each unit?
A. The maximum and minimum attainable equivalent availabilities, which are presented along with their respective target availabilities on page 4 of Schedule 2 of my exhibit, were determined per GPIF Implementation Manual procedures for Gulf.

Q. Mr. Nicholson, has Gulf completed the GPIF minimum filing requirements data package?
A. Yes, we have completed the minimum filing requirements data package. Schedule 3 of my exhibit contains this information.

Q. Mr. Nicholson, would you please summarize your testimony?
A. Yes. Gulf asks that the Commission accept:

1. Crist Unit 7, Daniel Units 1 and 2, Smith Unit 3, and Scherer Unit 3 for inclusion under the GPIF for the period of January 1, 2020 through December 31, 2020.
2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 26 of Schedule 1 and also on page 5 of Schedule 3 of my exhibit.
3. The target, maximum attainable, and minimum attainable equivalent availabilities, as proposed by the Company and as shown on page 4 of Schedule 2 and also on page 5 of Schedule 3 of my exhibit.
4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and on pages 17 through 26 of Schedule 3 of my exhibit, for use in adjusting the annual actual unit heat rates to target conditions.

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

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I hold a Bachelor of Arts degree in Economics from the University of New Orleans and a Master of Arts degree in Economics from the University of South Florida. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, and during my tenure there I assumed positions of increasing responsibility. I have over 20 years of electric utility experience, including load forecasting, managing cost recovery clauses, project management, and rate setting activities for wholesale and retail rate cases. My current position is Manager, Rates, and my responsibilities include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2018 through December 2018 for the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause") and the Capacity Cost Recovery Clause ("Capacity Clause"), as well as the Optimization Mechanism gain sharing allocation for the period.

Q. What is the source of the data which you will present by way of testimony or exhibit in this process?

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

Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

A. Yes. Exhibit No. PAR-1, consisting of five documents which are described later in my testimony, was prepared under my direction and supervision.

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Clause for the period January 2018 through December 2018?

A. The final true-up amount for the Capacity Clause for the period January 2018 through December 2018 is an under–recovery of $0, if the Commission approves the company's petition for mid-course correction for capacity factors submitted in Docket No. 20190001-EI on January 15, 2019. Tampa Electric proposed to include the actual 2018 end of period under-recovery amount of $5,458,886 in its 2019 mid-course factors.

Q. Please describe Document No. 1 of your exhibit.

A. Document No. 1, page 1 of 4, entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of

Final True-up Variances for the Period January 2018 Through December 2018," provides the calculation for the final under–recovery of $0. The actual capacity cost under-recovery, including interest, was $5,458,886 for the period January 2018 through December 2018 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $5,458,886 under-recovery included in the company's January 15, 2019 petition for mid-course correction submitted in Docket No. 20190001-EI, results in a final under-recovery of $0 for the period, as identified in Document No. 1, page 4 of 4.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2018 through December 2018?

A. The final Fuel Clause true-up for the period January 2018 through December 2018 is an under-recovery of $43,986,397. The actual fuel cost under-recovery, including interest, was $36,970,912 for the period January 2018 through December 2018. This $36,970,912 amount, less the $7,015,485 projected over-recovery amount approved in Order No. PSC-2018-0610-FOF-EI, issued December 26, 2018 in Docket No. 20180001-EI, results in a net under-recovery amount for the period of $43,986,397.

Q. What is the estimated effect of the $43,986,397 under-recovery for the January 2018 through December 2018 period on residential bills during the January 2020 through December 2020 period?

A. The $43,986,397 under-recovery will increase a 1,000 kWh residential bill by approximately $2.26.

Q. Please describe Document No. 2 of your exhibit.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2018 Through December 2018." It shows the calculation of the final fuel under-recovery of $43,986,397.

Line 1 shows the total company fuel costs of $673,683,598 for the period January 2018 through December 2018. The jurisdictional amount of total fuel costs is $673,683,598, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual under-recovered fuel costs for the period, shown on line 4. The resulting $43,839,292 under-recovered fuel costs for the period, adjustments, interest, true-up collected, and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual under-recovery amount of $36,970,912 shown on line 9. The $36,970,912 actual under-recovery amount less the $7,015,485 projected over-recovery amount shown on line 10, results in a final under-recovery amount of $43,986,397 for the period January 2018 through December 2018, as shown on line 11.

Q. Please describe the adjustments in the amount of ($144,678), as shown on line 5.

A. There are three adjustments included. The first adjustment, in the amount of ($190,412) is the January 2018 true-up adjustment to the December 2017 adjustment for Big Bend Unit 2 outage replacement power cost. The initial amount was estimated, and Tampa Electric completed the detailed hourly analysis needed to calculate the final amount and booked the true-up, in January 2018. The second adjustment is for interest on this adjustment, in the amount of $2,670, and was booked in February 2018. The third adjustment occurred in May 2018 in the amount of $43,064. It reflects the impact of tax reform on the company’s capital projects recovered through the fuel clause for the period January 2018 through April 2018.

Q. Please describe Document No. 3 of your exhibit.

A. Document No. 3 is entitled "Tampa Electric Company Calculation of True-up Amount Actual *vs.* Original Estimates for the Period January 2018 Through December 2018." It shows the calculation of the actual under-recovery compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2018 through December 2018?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost is $45,880,669 greater than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2018 through December 2018?

A. As shown on line C3 of Document No. 3, the company collected $2,596,083, or 0.4 percent greater jurisdictional fuel revenues than originally estimated.

Q. Please describe Document No. 4 of your exhibit.

A. Document No. 4 contains Commission Schedules A1 and A2 for the month of December and the year-end period-to-date summary of transactions for each of Commission Schedules A6, A7, A8, A9, as well as capacity information on Schedule A12.

Q. Please describe Document No. 5 of your exhibit.

A. Document No. 5 provides the capital costs and fuel savings for the Polk Unit 1 and the Big Bend Units 1-4 ignition conversion projects for the period January 2018 through December 2018. This document also contains the capital structure components and cost rates relied upon to calculate the revenue requirements rate of return on capital projects recovered through the fuel clause.

The Polk Unit 1 ignition conversion project capital costs, including depreciation and return, for the period January 2018 through December 2018 are less than the project's fuel savings and provide a net benefit to customers. This is shown on Document No. 5, page 1, line 33. Therefore, the Polk Unit 1 ignition conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-2012-0498-PAA-EI, issued in Docket No. 20120153-EI on September 27, 2012.

The Big Bend Units 1-4 ignition conversion project capital costs, including depreciation and return, for the period are less than the fuel savings resulting from the project, and provide a net benefit to customers, as shown on Document No. 5, page 2, line 33. Therefore, the Big Bend Units 1-4 ignition conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-2014-0309-PAA-EI, issued in Docket No. 20140032-EI on June 12, 2014.

Optimization Mechanism

Q. Was Tampa Electric's sharing of Optimization Mechanism gains allocated in accordance with FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI, on November 27, 2017?

A. Yes. As shown in the testimony and exhibit of Tampa Electric witness John C. Heisey filed contemporaneously in this docket, the sharing of Optimization Mechanism gains was allocated in accordance with FPSC Order No. PSC-2017-0456-S-EI. Total gains were $6,367,256. Under the sharing mechanism, Tampa Electric customers receive $5,246,902, and the company earned an incentive of $1,120,353 as a result of the company's Optimization Mechanism activities during 2018. Customers received the gains from these transactions during 2018, and Tampa Electric requests Commission approval to collect the company's $1,120,353 incentive in its 2020 fuel factors.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190001-EI
FILED: 7/26/2019

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Regulatory Affairs.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I assumed positions of increasing responsibility over time. My current position is Director of Regulatory Affairs.

At Tampa Electric, I have accumulated over 20 years of electric utility experience in the areas of load forecasting; management of the fuel and purchased power, capacity, and environmental cost recovery clauses; rate setting and rate filings; and regulatory project management activities. I also oversee the coordination and filing of all Tampa Electric and Peoples Gas filings with federal and state regulatory agencies. I am a member of the Southeastern Electric Exchange Rates and Regulation committee.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2019 through December 2019 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the January 2020 through December 2020 projection period. My testimony addresses the recovery of the fuel and purchased power costs as well as capacity costs for the year 2019, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2020 fuel and purchased power and capacity cost recovery factors.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, I have prepared Exhibit No. PAR-2, which consists of three documents. Document No. 1 includes schedules E1-B, E-2, E-3, E-4, E-5, E-6, E-7, E-8, and E-9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2019 through December 2019. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period January 2019 through December 2019. Document No. 3 provides the actual/estimated capital costs during the period of January 2019 through December 2019 for projects authorized for recovery through the fuel clause. Document No. 3 also provides the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for such projects. These documents are furnished as support for the actual/estimated true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2020 through December 2020 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period of January 2020 through December 2020 is an under-recovery of $30,742,026.

Q. How did Tampa Electric calculate the estimated net true-up to be applied in the January 2020 through December 2020 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2020 includes the final true-up amount for the period January 2018 through December 2018 and the actual/estimated true-up amount for the period January 2019 through December 2019. This calculation is shown on Schedule E1-A of Exhibit No. PAR-2, Document No. 1.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for the period January 2018 through December 2018?

A. The final 2018 true-up is an under-recovery of $43,986,397. The actual fuel cost under-recovery, including interest, is $36,970,912 for the period January 2018 through December 2018. The $36,970,912 under-recovery, less the actual/estimated over-recovery true-up amount of $7,015,485 approved in Order No. PSC-2018-0610-FOF-EI, issued December 26, 2018 in Docket No. 20180001-EI, results in a net under-recovery amount for the period of $43,986,397.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery amount for the period January 2019 through December 2019?

A. The net 2019 actual/estimated fuel and purchased power cost recovery true-up is an over-recovery of $13,244,371 for the January 2019 through December 2019 period. This includes adjustments to reflect the company's mid-course correction true-up amounts. It is the actual/estimated under-recovery amount for the period January 2019 through December 2019, less the projected under-recovery true-up included in the period April 2019 through December 2019 mid-course correction factors, plus the difference between the 2018 actual/estimated true-up amount included in the original 2019 factors and the amount actually refunded before the mid-course correction factors became effective. The actual/estimated true-up for the period January 2019 through December 2019 is an under-recovery of $27,562,704. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit No. PAR-2, Document No. 1 on Schedule E1-B. The $27,562,704 under-recovery less the $35,545,462 projected under-recovery true-up approved in Order No.

PSC-2019-0109-PCO-EI, issued on March 22, 2019 in Docket No. 20190001-EI, plus the $5,261,613 difference between the 2018 actual/estimated true-up amount and the amount refunded during the period January 2019 through March 2019, results in a net actual/estimated over-recovery amount for the period of $13,244,371. The calculation is shown on Schedule E1-A of Exhibit No. PAR-2, Document No. 1.

Q. What did Tampa Electric calculate as the difference between the actual/estimated true-up amount for the period January 2018 through December 2018 filed in 2018 and the actual amount collected in 2019?

A. The difference between the actual/estimated true-up amount for the period January 2018 through December 2018, which was included in the factors for the period January 2019 through December 2019, and the actual amount refunded during 2019 is $5,261,613. This amount is the actual/estimated over-recovery true-up of $7,015,485 included in the original 2019 fuel factors, less $1,753,872, which represents the $584,624 refunded each month during the three-month period January 2019 through March 2019 before the revised mid-course correction factors took effect.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2020 through December 2020 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2020 through December 2020 is an under-recovery of $2,179,217 as shown in Exhibit No. PAR-2, Document No. 2, page 2 of 5.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2020 through December 2020 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2020 capacity cost recovery factors includes the final under-recovery amount for 2018 and the actual/estimated true-up amount for January 2019 and December 2019. Due to the April 2019 mid-course correction, the net true-up amount also includes the portion of the actual/estimated 2018 true-up recovered in the original capacity factors effective during the months of January 2019 through March 2019 as well as the projected true-up amount included in the mid-course factors effective for April 2019 through December 2019.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2018?

A. The final 2018 under-recovery is $5,458,886. The company rolled this amount forward into 2019, including it in the 2019 mid-course correction factors. Therefore, the final 2018 true-up amount for 2018 is $0.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2019 through December 2019?

A. The actual/estimated true-up amount is an over-recovery of $1,422,896 as shown on Exhibit No. PAR-2, Document No. 2, page 1 of 4.

Q. What did Tampa Electric calculate as the net capacity cost recovery true-up amount for the period January 2019 through December 2019?

A. The net capacity cost recovery true-up amount for the period January 2019 through December 2019 is an under-recovery of $2,179,217. The final 2018 under-recovery amount is $5,458,886. The company rolled this amount forward to calculate the revised under-recovery true-up amount of $1,160,527 included in the mid-course cost recovery factors for the period April 2019 through December 2019, as approved in Order No. PSC-2019-0109-PCO-EI, issued March 22, 2019 in Docket No. 20190001-EI. The company also collected $696,246, or $232,082 monthly over the period January 2019 through March 2019, of the prior period under-recovery true-up included in the original 2019 factors. The sum of these three items is an under-recovery amount of $3,602,113. The net capacity cost recovery true-up amount for the period 2019 is calculated as the $1,422,896 actual/estimated over-recovery plus the $3,602,113 mid-course under-recovery, or a net true-up under-recovery amount of $2,179,217. This calculation is shown on Exhibit No. PAR-2, Document No. 2, page 1 of 4.

Capital Projects Approved for Fuel Clause Recovery

Q. Please describe the capital project costs that have been authorized for recovery through the fuel clause.

A. Document No. 3 of Exhibit No. PAR-2 provides the capital cost and fuel savings for the Big Bend Units 1 through 4 ignition conversion project for the period January 2019 through December 2019. This document also contains the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return on capital projects recovered through the fuel clause.

The Big Bend Units 1 through 4 ignition conversion project capital costs, including depreciation and return, for the period January 2019 through December 2019 are less than the project fuel savings, as shown on Exhibit No. PAR-2, Document No. 3, Page 1, line 33. Therefore, the Big Bend Units 1 through 4 ignition conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-2014-0309-PAA-EI, issued in Docket No. 20140032-EI on June 12, 2014.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190001-EI
FILED: 09/03/2019

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Regulatory Affairs.

Q. Have you previously filed testimony in Docket No. 20190001-EI?

A. Yes, I submitted direct testimony on March 1, 2019 and July 26, 2019.

Q. Has your job description, education, or professional experience changed since you last filed testimony in this docket?

A. No, it has not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors for January 2020 through December 2020. I also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2020.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. Exhibit No. PAR-3, consisting of four documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors. Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, includes Schedules E1 through E10 for January 2020 through December 2020 as well as Schedule H1 for 2017 through 2020. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 4 presents the capital costs and fuel savings for the company projects that have been approved through the fuel clause, as well as the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the projects.

Capacity Cost Recovery

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

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. PAR-3, Document No. 1, page 3 of 4.

Q. What payments are included in Tampa Electric's capacity cost recovery factors?

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. PAR-3, Document No. 1, Tampa Electric requests recovery of $1,620,007 after jurisdictional separation, prior year true-up, and application of the revenue tax factor, for estimated expenses in 2020.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2020 through December 2020.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per Kw**
RS Secondary	0.010	
GS and CS Secondary	0.008	
GSD, SBF Standard		
Secondary		0.03
Primary		0.03
Transmission		0.03
IS, IST, SBI		
Primary		0.03
Transmission		0.03
GSD Optional		
Secondary	0.007	
Primary	0.007	
Transmission	0.007	
LS1 Secondary	0.002	

These factors are shown in Exhibit No. PAR-3, Document No. 1, page 3 of 4.

Q. How does Tampa Electric’s proposed average capacity cost recovery factor of 0.008 cents per kWh compare to the factor for April 2019 through December 2019?

A. The proposed capacity cost recovery factor of 0.008 cents per kWh for the January 2020 through December 2020 period is 0.017 cents per kWh (or $0.17 per 1,000 kWh) greater than the average capacity cost recovery factor credit of 0.009 cents per kWh for the April 2019 through December 2019 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the year 2020?

A. The appropriate amount for the 2020 period is 3.016 cents per kWh before the application of the time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. PAR-3, Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2020 through December 2020.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF"), true-up factors, and Optimization Mechanism factor are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $4,141,330, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up amount to be applied during the January 2020 through December 2020 period. The net true-up amount is an under-recovery of $30,742,026. Lastly, Schedule E1-C indicates the Optimization Mechanism gain of $1,120,353.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2020 through December 2020. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering level.

Q. Please describe the information presented on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. PAR-3, Document No. 3 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2020 through December 2020.

A.

Metering Voltage Level	Fuel Charge Factor (Cents per kWh)
Secondary	3.016
Tier I (Up to 1,000 kWh)	2.702
Tier II (Over 1,000 kWh)	3.702
Distribution Primary	2.986
Transmission	2.956
Lighting Service	2.989
Distribution Secondary	3.162 (on-peak)
	2.953 (off-peak)

Metering Voltage Level	Fuel Charge Factor (Cents per kWh)
Distribution Primary	3.130 (on-peak)
	2.923 (off-peak)
Transmission	3.099 (on-peak)
	2.894 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.016 cents per kWh compare to the levelized fuel adjustment factor for the April 2019 through December 2019 period?

A. The proposed fuel charge factor of 3.016 cents per kWh is 0.211 cents per kWh (or $2.11 per 1,000 kWh) lower than the average fuel charge factor of 3.227 cents per kWh for the April 2019 through December 2019 period.

Capital Projects Approved for Fuel Clause Recovery

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project costs for the period January 2020 through December 2020?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, are $1,657,489. This is shown in Exhibit No. PAR-3, Document No. 4.

Q. Does Tampa Electric's estimated Big Bend Units 1-4 ignition oil conversion project fuel savings exceed costs for the period January 2020 through December 2020?

A. Yes, fuel savings exceed costs for the period January 2020 through December 2020. This information is also presented in Exhibit No. PAR-3, Document No. 4.

Q. Should Tampa Electric's Big Bend Units 1-4 ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2020 through December 2020 estimated fuel savings are greater than the projected capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-2014-0309-PAA-EI, issued in Docket No. 20140032-EI on June 12, 2014.

Q. Please describe the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for this project.

A. The capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the company's projects that are approved for recovery through the fuel clause are shown in Document No. 4.

Q. Is Tampa Electric required to adjust its projected weighted average cost of capital calculations to avoid a tax normalization violation, which may occur in certain circumstances described in the utilities' unopposed joint motion to modify Order No. 2012-0425-PAA-EU, submitted in this docket on August 21, 2019?

A. No, an adjustment is not required for 2020. Tampa Electric expects to meet the limitation provision for the projected period. Therefore, the methodology used to calculate the revenue requirement rate of return shown on Document No. 4 is that described in Order No. 2012-0425-PAA-EU, and the use of the current methodology does not violate the tax normalization requirement.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric project a 2020 wholesale incentive benchmark that is derived in accordance with Order No. PSC-2001-2371-FOF-EI issued in Docket No. 20010283-EI?

A. No. Effective January 1, 2018, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017, the company's Optimization Mechanism replaced the existing short-term wholesale sales incentive mechanism, and as a result no wholesale incentive benchmark is required for the 2020 projection.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its base, capacity, fuel and purchased power, environmental, and energy conservation cost recovery factors on a 1,000 kWh residential customer's bill?

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $1.06 beginning January 2020, when compared to the April 2019 through December 2019 charges. For the month of January 2020, a one-time final tax savings credit will be applied to customer bills. For a 1,000 kWh residential bill, the credit represents an additional decrease of $9.06. These amounts are shown in Exhibit No. PAR-3, Document No. 2, on Schedule E10.

Q. When should the new rates take effect?

A. The new rates should take effect concurrent with meter readings for the first billing cycle for January 2020.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Unit Commitment.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I am a registered Professional Engineer in the state of Florida, and I have accumulated 20 years of electric utility work experience. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services and have held various engineering positions at Tampa Electric's power generating stations and in the Operations

Planning Department where I was responsible for unit performance analysis and reporting. In 2008, I was promoted to Manager, Operations Planning, and in 2011, NERC Compliance was added to my current responsibilities. In 2017, I was promoted to Manager, Unit Commitment, where I am responsible for portfolio optimization of Tampa Electric’s generation assets.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and heat rate used to determine the Generating Performance Incentive Factor (“GPIF”) for the period January 2018 through December 2018. I will also compare these results to the targets established for the period.

Q. Have you prepared an exhibit to support your testimony?

A. Yes, I prepared Exhibit No. BSB-1, consisting of two documents. Document No. 1, entitled “GPIF Schedules” is consistent with the GPIF Implementation Manual approved by the Commission. Document No. 2 provides the company’s Actual Unit Performance Data for the 2018 period.

Q. Which generating units on Tampa Electric’s system are included in the determination of the GPIF?

A. Big Bend Units 2 through 4, Polk Units 1 and 2 and Bayside Units 1 and 2 are included in the calculation of the GPIF.

Q. Have you calculated the results of Tampa Electric’s performance under the GPIF during the January 2018 through December 2018 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 32. Based upon 4.464 Generating Performance Incentive Points (“GPIP”), the result is a reward amount of $4,141,330 for the period.

Q. Please proceed with your review of the actual results for the January 2018 through December 2018 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $2,763,199,709. This produces the maximum penalty or reward amount of $9,277,090 as shown on line 23.

Q. Will you please explain how you arrived at the actual equivalent availability results for the seven units included within the GPIF?

A. Yes. Operating data for each of the units is filed monthly with the Commission on the Actual Unit Performance Data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the 12 months provides the basis for the GPIF.

Q. Are the actual equivalent availability results shown on Document No. 1, page 6 of 32, column 2, directly applicable to the GPIF table?

A. No. Adjustments to actual equivalent availability may be required as noted in Section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 32, column 4. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 2

On this unit, 575.0 planned outage hours were originally scheduled for 2018. Actual outage activities required 1,682.2 planned outage hours. Consequently, the actual equivalent availability of 70.0 percent is adjusted to 80.9 percent as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 3

On this unit, 576.0 planned outage hours were originally scheduled for 2018. Actual outage activities required 470.8 planned outage hours. Consequently, the actual equivalent availability of 76.5 percent is adjusted to 75.5 percent as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 4

On this unit, 576.0 planned outage hours were originally scheduled for 2018. Actual outage activities required 1,676.7 planned outage hours. Consequently, the actual equivalent availability of 60.2 percent is adjusted to 69.5 percent as shown on Document No. 1, page 9 of 32.

Polk Unit No. 1

On this unit, 1,512.0 planned outage hours were originally scheduled for 2018. Actual outage activities required 2,460.1 planned outage hours. Consequently, the actual equivalent availability of 60.7 percent is adjusted to 69.8 percent, as shown on Document No. 1, page 10 of 32.

Polk Unit No. 2

On this unit, 505.0 planned outage hours were originally scheduled for 2018. Actual outage activities required 175.3 planned outage hours. Consequently, the actual equivalent availability of 93.8 percent is adjusted to 90.1 percent, as shown on Document No. 1, page 11 of 32.

Bayside Unit No. 1

On this unit, 1,297.0 planned outage hours were originally scheduled for 2018. Actual outage activities required 468.3 planned outage hours. Consequently, the actual equivalent availability of 93.0 percent is adjusted to 83.7 percent, as shown on Document No. 1, page 12 of 32.

Bayside Unit No. 2

On this unit, 1,631.0 planned outage hours were originally scheduled for 2018. Actual outage activities required 1,718.0 planned outage hours. Consequently, the actual equivalent availability of 77.1 percent is adjusted to 78.0 percent, as shown on Document No. 1, page 13 of 32.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 32, column 4. This number is incorporated in the respective GPIP table for each particular unit, shown on pages 24 of 32 through 30 of 32. Page 4 of 32 summarizes the weighted equivalent availability points to be awarded or penalized.

Q. Will you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for Tampa Electric’s seven GPIF units are shown on Document No. 1, page 6 of 32. The adjustment was developed based on the guidelines of Section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 32, column 9. The heat rate value is incorporated in the respective GPIP table for the particular unit, shown on pages 24 through 30 of 32. Page 4 of 32 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January 2018 through December 2018 period?

A. This is shown on Document No. 1, page 2 of 32. The weighting factors shown on page 4 of 32, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 32, column 4, are substituted within the equation found on page 32 of 32. The resulting value of 4.464 is located in the GPIF table on page 2 of 32, and the reward amount of $4,141,330 is calculated using linear interpolation.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Tampa Electric met this constraint, limiting the total potential reward and penalty incentive dollars to $9,277,090, as shown in Document No. 1, pages 2 and 3.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Resource Planning.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor's degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 20 years of utility experience with an emphasis in state and federal regulatory matters, fuel procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In 2017, I assumed responsibility for Portfolio Optimization which includes unit commitment, near-term maintenance planning, and natural gas and wholesale power trading. In December 2018, I assumed the role of Director Resource Planning.

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

A. Yes. I have submitted written testimony in the annual fuel docket since 2011. In 2015, I testified in Docket No. 20150001-EI regarding natural gas hedging. I have also testified before the Commission in Docket No. 20120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle Conversion project.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Commission's review, information regarding the 2018 results of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 20011605-EI and approved by the Commission in Order No. PSC-2002-1484-FOF-EI.

Q. Do you wish to sponsor an exhibit in support of your testimony?

A. Yes. Exhibit No. JBC-1, entitled Tampa Electric's 2018 Hedging Activity True-up, was prepared under my direction and supervision. This report describes the company's risk management activities and results for the calendar year 2018.

Q. What is the source of the data you present in your testimony in this proceeding?

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

Natural Gas Financial Hedging

Q. Please describe the natural gas financial hedging moratorium that began in 2016 and its effects on 2018 risk management activities.

A. On October 24, 2016, electric investor-owned utilities DEF, Gulf and Tampa Electric, collectively the IOUs, Office of Public Counsel, the Florida Industrial Power Users Group, and the Florida Retail Federation jointly entered into a Stipulation and Agreement ("Agreement"). Under the terms of the Agreement, the IOUs agreed to put in place a 100 percent moratorium on any new hedges, effective immediately upon the Commission's approval of the Agreement, with that moratorium extending through calendar year 2017. The Agreement was approved by the Commission on December 5, 2016, with the issuance of Order No. PSC-2016-0547-FOF-EI. By Commission vote memorialized in Order No. PSC-2017-0134-PCO-EI issued April 13, 2017, Tampa Electric was not required to file a 2018 Risk Management Plan, effectively extending the hedging moratorium.

Tampa Electric prudently followed its 2016 Risk Management Plan, Commission Order No. PSC-2016-0547-FOF-EI, and Commission Order No. PSC-2017-0134-PCO-EI in utilizing financial hedges already in place prior to the moratorium to mitigate volatility of natural gas prices during the period January 2018 through December 2018.

Q. What does Tampa Electric plan to do when the hedging moratorium ends?

A. In accordance with the company’s 2017 Amended and Restated Stipulation and Settlement Agreement approved by

Commission Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket No. 20170210-EI, Tampa Electric will not enter into any new natural gas financial hedging contracts for fuel from January 1, 2018 through December 31, 2022.

Q. Did Tampa Electric have any natural gas financial hedging contracts that were entered prior to the start of the hedging moratorium and effective during 2018?

A. Yes. Tampa Electric has reported on the natural gas financial hedging contracts entered prior to Commission approval of the hedging moratorium, and the company has not entered any new financial hedging contracts since the moratorium began. All such hedging contracts have been settled as of the end of November 2018.

Risk Management Activities

Q. What were the results of Tampa Electric’s risk management activities in 2018?

A. As outlined in Tampa Electric’s 2018 Hedging Activity True-up, filed as an exhibit to this testimony, the company followed a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. The company's 2018 risk management activities include financial hedges established prior to the moratorium. Tampa Electric's 2018 natural gas hedging activities resulted in a net settlement loss of approximately $232,000. These results are due to the market conditions experienced in the past two years as Tampa Electric has not placed any new financial hedges on its natural gas purchases since the moratorium began. The 2018 financial hedges were successful in achieving the risk management plan objective of reducing price volatility while maintaining a reliable fuel supply.

Q. Does Tampa Electric implement physical hedges for natural gas?

A. No, Tampa Electric does not hedge natural gas pricing through physical gas supply contracts. Tampa Electric does hedge its natural gas supply through diversification. Tampa Electric physically hedges its supply using a variety of sources, delivery methods, inventory locations and contractual terms to enhance the company's supply reliability and flexibility to cost-effectively meet changing operational needs.

Tampa Electric continually pursues new creditworthy counterparties and maintains contracts for gas supplies from various regions and on different pipelines. The company also contracts for pipeline capacity to access non-conventional shale gas production which is less sensitive to interruption by hurricanes. Additionally, Tampa Electric has storage capacity with Bay Gas Storage near Mobile, Alabama. All of these actions enhance the effectiveness of Tampa Electric's gas supply portfolio.

Q. Does Tampa Electric use a hedging information system?

A. Yes, Tampa Electric uses the Allegro System ("Allegro"). Allegro supports sound hedging practices with its contract management, separation of duties, credit tracking, transaction limits, deal confirmation, risk exposure analysis and business report generation functions. Allegro tracks all existing financial natural gas hedging transactions, and the system produces risk management reports.

Q. Did the company use financial hedges for commodities other than natural gas in 2018?

A. No. Tampa Electric did not use financial hedges for commodities other than natural gas in 2018. Tampa Electric's generation units are fueled primarily by coal and natural gas. The price of coal has historically been stable compared to the prices of oil and natural gas. In addition, there is not an organized, liquid, market for financial hedging instruments for the high-sulfur Illinois Basin coal that Tampa Electric uses at Big Bend Station, its largest coal-fired generation facility. Tampa Electric consumes a small amount of oil; however, its low and erratic usage pattern makes price hedging impractical. Similarly, Tampa Electric did not use financial hedges for wholesale power transactions because a liquid, published market does not exist for power in Florida.

Q. How does Tampa Electric assure physical supply of other commodities?

A. Tampa Electric assures sufficient physical supply of coal and oil through supply diversification, inventory sufficiency, and delivery flexibility. For coal, the company enters into a portfolio of contracts with differing terms and various suppliers to obtain the types of coal used in its electric generation system. Through a competitive bid process, supplier diversity and transportation flexibility, Tampa Electric obtains competitive prices with valuable quality and transportation flexibility by selecting from a wide range of purchase options.

Q. What is the basis for your request to recover the commodity and transaction costs described above?

A. Tampa Electric requests cost recovery pursuant to Commission Order No. PSC-2002-1484-FOF-EI, in Docket No. 20011605-EI:

> Each investor-owned electric utility shall be authorized to charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions for natural gas, residual oil, and purchased power contracts tied to the price of natural gas.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony was inserted.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190001-EI
FILED: 09/03/2019

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEREMY B. CAIN

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

A. My name is Jeremy B. Cain. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Asset Management.

Q. Please provide a brief description of your educational background and work experience.

A. I hold a Bachelor of Science degree in Mechanical Engineering in 2003 from the University of New Brunswick, Canada, and I am a registered Professional Engineer in Canada. I have accumulated 10 years of experience in the electric utility industry, with experience in the areas of unit maintenance manager, project manager for a unit upgrade, operations manager for that plant, as well as various other engineering positions, including responsibility for physical asset management. In my current role I am responsible for development of Tampa

Electric’s Asset Management programs and processes, specifically for the Bayside Power Station, and coordinating these programs with the Asset Management processes throughout Energy Supply. Asset Management programs include work management processes, reliability programs, and information technology, operational and capital investment analysis, recommendations, and planning to maintain and improve the performance of the generating units.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric’s methodology for determining the various factors required to compute the Generating Performance Incentive Factor (“GPIF”) as ordered by the Commission.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. Exhibit No. JC-1, consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2020 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four natural gas combined cycle units and one coal unit are included. These are Polk Units 1 and 2, Bayside Units 1 and 2, and Big Bend Unit 4.

Q. Does your exhibit comply with the Commission's approved GPIF methodology?

A. Yes. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80 percent of the estimated system net generation. The units Tampa Electric proposes to use for the period January 2020 through December 2020 represent 87 percent of the total forecasted system net generation for this period.

To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. The methodology was approved by the Commission in Order No. PSC-2006-1057-FOF-EI issued in Docket No. 20060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes, Polk Unit 2 and Bayside Unit 1 outages were identified as outliers and removed.

Q. Did Tampa Electric make any other adjustments?

A. Yes. As allowed per Section 4.3 of the GPIF Implementation Manual, the Forced Outage and Maintenance Outage Factors were adjusted to reflect recent unit performance and known unit modifications or equipment changes.

Q. Please describe how Tampa Electric developed the various factors associated with GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2020 period. A range of potential improvements and degradations were determined for each of these metrics.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100 percent to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the four units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2020 period, the projected EUOF for Bayside Unit 1 is 1.7 percent, the POF is 6.6 percent. Therefore, the target EAF for Bayside Unit 1 equals 91.7 percent or:

$$100\% - (1.7\% + 6.6\%) = 91.7\%$$

This is shown on Page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived using the following formula:

$$EAF_{MAX} = 1 - [0.80\ (EUOF_T) + 0.95\ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. Calculating the maximum incentive points, a 20 percent reduction in EUOF, plus a five percent reduction in the POF is necessary. Continuing with the Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80\ (1.7\%) + 0.95\ (6.6\%)] = 92.4\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing using the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (1.7\%) + 1.10\ (6.6\%)] = 90.3\%$$

The equivalent availability maximum and minimum for the other four units are computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January through December 2020 are shown on page 17 of Document No. 1. One GPIF unit has a major planned outage 28 days or greater in 2020; therefore, one Critical Path Method diagram is provided.

Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for planned outages from February 29, 2020 to March 11, 2020 and December 2, 2020 to December 13, 2020. There are 576 planned outage hours scheduled for the 2020 period, with a total of 8,784 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 6.6 percent or:

$$\frac{576}{8,784} \times 100\% = 6.6\%$$

The factor for each unit is shown on pages 5 and 12 through 16 of Document No. 1. Polk Unit 1 has a POF of 8.5 percent. Polk Unit 2 has a POF of 12.6 percent. Bayside Unit 2 has a POF of 6.6 percent, and Big Bend Unit 4 has a POF of 21.8 percent.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. Projected factors are based upon historical unit performance. For each unit, the three most recent July through June annual periods formed the basis of the target development. Historical data and target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 1.7 percent for Bayside Unit 1. The EUOF of Bayside Unit 1 is verified by the data shown on page 15, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

Or

$$EUOF = \frac{(42 + 111)}{8,784} \times 100\% = 1.7\%$$

Relative to Bayside Unit 1, the EUOF of 1.7 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Polk Unit 1

The projected EUOF for this unit is 16 percent. The unit will have two planned outages in 2020, and the POF is 8.5 percent. Therefore, the target equivalent availability for this unit is 75.5 percent.

Polk Unit 2

The projected EUOF for this unit is 2.5 percent. The unit will have two planned outages in 2020, and the POF is 12.6 percent. Therefore, the target equivalent availability for this unit is 84.9 percent.

Bayside Unit 1

The projected EUOF for this unit is 1.7 percent. The unit will have two planned outages in 2020, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 91.7 percent.

Bayside Unit 2

The projected EUOF for this unit is 4.5 percent. The unit will have two planned outages in 2020, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 88.9 percent.

Big Bend Unit 4

The projected EUOF for this unit is 22.8 percent. The unit will have two planned outages in 2020, and the POF is 21.8 percent. Therefore, the target equivalent availability for this unit is 55.4 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 84.9 percent is shown on page 5 of Document No. 1.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent

Unplanned Outage Factor for Bayside Unit 1 on page 15 of Document No. 1. Except for the months of February, March, and December, the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled for these months. During the months of February, March, and December, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to the scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining unit metrics, which are subsequently converted to factors. Therefore,

$$EFOF + EMOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the aforementioned agreed upon GPIF methodology and co-firing.

Q. How were the targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis for the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any period of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 24 through 28 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by the computer program for each unit. These curves are also used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch and fuel.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2020 period.

A. The heat rate target for Polk Unit 1 is 10,018 Btu/Net kWh with a range of ±1,411 Btu/Net kWh. The heat rate target for Polk Unit 2 is 7,209 Btu/Net kWh with a range of ±394 Btu/Net kWh. The heat rate for Bayside Unit 1 is

7,379 Btu/Net kWh with a range of ±119 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,499 Btu/Net kWh with a range of ±250 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,837 Btu/Net kWh with a range of ±427 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within a range for each target. This is shown on page 4, and pages 7 through 11 of Document No. 1.

Q. Do these heat rate targets and ranges meet the Commission's requirements?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in determining the GPIF targets?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown in Document No. 1, pages 7 through 11. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $435,826,930 is shown on

Document No. 1, page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

Column 4 totals $21,602,740, which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing unit savings by the total. For Bayside Unit 1, the weighting factor for average net operating heat rate is 7.6 percent as shown in the right-hand column on Document No. 1, page 6. Pages 7 through 11 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, as shown on page 10 of Document No. 1, if Bayside Unit 1, operates at 7,260 average net operating heat rate, fuel savings would equal $1,649,500, and +10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 of Document No. 1 is a summary of the tables on pages 7 through 11. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $21,602,740. The right-hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2020 is $3,209,099,543. This produces the maximum allowed jurisdictional incentive of $10,774,122 shown on line 21.

Q. Are there any constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. As Order No. PSC-2013-0665-FOF-EI, issued in Docket No. 20130001-EI on December 18, 2013 states, incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $10,774,122.

Q. Please summarize your direct testimony.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP).

$$\begin{aligned} GPIP = (&0.0315\ EAP_{PK1} + 0.6840\ EAP_{PK2} \\ &+ 0.05630\ EAP_{BAY1} + 0.0839\ EAP_{BAY2} \\ &+ 0.0140\ EAP_{BB4} + 0.3596\ HRP_{PK2} \\ &+ 0.0764\ HRP_{BAY1} + 0.1543\ HRP_{BAY2} \\ &+ 0.0443\ HRP_{BB4} + 0.1115\ HRP_{PK1}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points

EAP = Equivalent Availability Points awarded/deducted for Polk Units 1 and 2, Bayside Units 1 and 2, and Big Bend Unit 4.

HRP = Average Net Heat Rate Points awarded/deducted for Polk Units 1 and 2, Bayside Units 1 and 2, and Big Bend Unit 4.

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2020 period?

A. Yes. Document No. 2 entitled "Summary of GPIF Targets" provides the availability and heat rate targets for each unit.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the Wholesale Marketing Group within the Wholesale Marketing & Fuels Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida and a Master of Business Administration degree in 2015 from Saint Leo University in Saint Leo, Florida. I am also a registered Professional Engineer within the State of Florida and a Certified Energy Manager through the Association of Energy Engineers. I joined Tampa Electric in 1990 as a cooperative education student. During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager, Gas and Power Origination in the Wholesale Marketing, Planning and Fuels Department. My responsibilities are to evaluate short and long-term power purchase and sale opportunities within the wholesale power market, assist in wholesale power and gas transportation origination and contract structures, and assist in combustion by-product contract administration and market opportunities. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, and other wholesale developers and independent power producers.

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

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I testified before this Commission in Docket Nos. 20030001-EI, 20040001-EI, and 20080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

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

A. The purpose of my testimony is to provide a description of Tampa Electric's purchased power agreements the company has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe Tampa Electric's purchased power strategy for mitigating price and supply-side risk, while providing customers with a reliable supply of economically priced purchased power.

Q. Please describe the efforts Tampa Electric makes to ensure that its wholesale purchases and sales activities are conducted in a reasonable and prudent manner.

A. Tampa Electric evaluates potential purchase and sale opportunities by analyzing the expected available amounts of generation and power required to meet the projected demand and energy of its customers. Purchases are made to achieve reserve margin requirements, meet customers' demand and energy needs, supplement generation during unit outages, and for economical purposes. When Tampa Electric considers making a power purchase, the company diligently searches for available supplies of wholesale capacity or energy from creditworthy counterparties. The objective is to secure reliable quantities of purchased power for customers at the best possible price.

Conversely, when there is a sales opportunity, the company offers profitable wholesale capacity or energy products to creditworthy counterparties. The company has wholesale power purchase and sale transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's wholesale purchase and sale activities are conducted in a reasonable and prudent manner.

Q. Has Tampa Electric reasonably managed its wholesale power purchases and sales for the benefit of its retail customers?

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order, No. PSC-1997-0262-FOF-EI, issued in Docket No. 19970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs and improve reliability. The company monitors its contractual rights with purchased power suppliers, as well as with entities to which wholesale power is sold, to detect and prevent any breach of the company's contractual rights. Tampa Electric continually strives to improve its knowledge of wholesale power markets and available opportunities within the marketplace. The company uses this knowledge to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power is available on Tampa Electric's system and market conditions allow.

Q. Please describe Tampa Electric's 2019 wholesale power purchases.

A. Tampa Electric assessed the wholesale power market and entered into short- and long-term purchases based on price and availability of supply. Approximately six percent of the company's expected needs for 2019 will be met using purchased power. This includes economy energy purchases, reliability purchases, as-available purchases from qualifying facilities, and forward purchases from Duke

Energy Florida (DEF) and the Florida Municipal Power Agency (FMPA).

Tampa Electric contracted to purchase non-firm energy from DEF for the period February 2019 through February 2020. Tampa Electric must take the energy during the months of June through October and has the option to take energy during the other months. The contract also provides flexibility to Tampa Electric to increase its purchase volume at times, which benefits customers as an economic option at times of high demand or during unit outages. The DEF purchase agreement provides savings to customers that flow through the company's optimization mechanism, which are described in the annual actual fuel docket reporting and accompanying testimony of Tampa Electric witness John C. Heisey.

Tampa Electric entered a purchase agreement for non-firm energy with FMPA for the period May 2019 through October 2019. The FMPA purchase also provides savings to customers through the company's optimization mechanism.

Tampa Electric has not secured other forward purchases for 2019 at this time. However, the company constantly searches for economic purchase opportunities that benefit customers. As other purchase opportunities materialize, the company evaluates each product to determine the viability of making it part of the supply portfolio Tampa Electric uses to serve customers.

Q. Does Tampa Electric anticipate entering into new wholesale power purchases for 2020 and beyond?

A. Similar to 2019, the company anticipates entering into new short-term power purchases for 2020. Furthermore, Tampa Electric will continue to evaluate its options beyond 2020 as well. The company's evaluation includes the review of new short- and long-term capacity and energy purchases and considers existing and anticipated system and market conditions. The goal of the evaluation is to identify and, if possible, secure, economic purchases that bring value to customers for the year 2020 and beyond. Currently, Tampa Electric expects purchased power to meet approximately one percent of its 2020 energy needs.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchased power supplies during major weather-related events, such as hurricanes?

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions. The strategy includes monitoring storm activity; evaluating the impact of storms on existing forward purchases and the rest of the wholesale power market; communicating with suppliers about their storm preparations and potential impacts to existing transactions, purchasing additional power on the forward market, if applicable, for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing sellers' fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Absent the threat of a hurricane, and for all other months of the year, the company evaluates economic combinations of short- and long-term purchase opportunities in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2019 and 2020.

A. Tampa Electric entered into various non-separated wholesale sales in 2019, and the company anticipates making additional non-separated sales during the balance of 2019 and 2020. The gains from these sales are distributed to Tampa Electric and its customers in accordance with the company's optimization mechanism.

Q. Please summarize your direct testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and these efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and short- and long-term power purchases. The company purchases in both physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. In addition to the cost benefits, this purchased power approach employs a diversified physical power supply strategy that enhances reliability. The company also enters into wholesale sales that benefit customers when market conditions allow.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

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

A. My name is John C. Heisey. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Trading.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from Pennsylvania State University with a Bachelor of Science in Business Logistics. I have over 25 years of power and natural gas trading experience, including employment at TECO Energy Source, FPL Energy Services, El Paso Energy, and International Paper. Prior to joining Tampa Electric, I was Vice President of Asset Trading for the Entegra Power Group LLC ("Entegra") where I was responsible for Entegra's energy trading activities. Entegra managed a large quantity of merchant capacity in bilateral and organized markets. I joined

Tampa Electric in September 2016 as the Manager of Gas and Power Trading and currently hold that position. I am responsible for all natural gas and power trading activities and work closely with Unit Commitment to provide low cost, reliable power to our customers. In addition, I am responsible for portfolio optimization and all aspects of the Optimization Mechanism.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Commission's review, the 2018 results of Tampa Electric's activities under the Optimization Mechanism, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017.

Q. Do you wish to sponsor an exhibit in support of your testimony?

A. Yes. Exhibit No. JCH-1, entitled Optimization Mechanism Results, was prepared under my direction and supervision. My exhibit demonstrates the gains for each type of activity included in the Optimization Mechanism and the gains sharing between customers and the company.

Q. Please provide an overview of the Optimization Mechanism.

A. The Optimization Mechanism is designed to create additional value for Tampa Electric’s customers while also providing an incentive to the company if certain customer-value thresholds are achieved. The Optimization Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization.

Q. Please describe Tampa Electric’s Optimization Mechanism submitted in Docket No. 20160160-EI and approved by Order No. PSC-2017-0456-S-EI.

A. Effective January 1, 2018, for the four-year period from 2018 through 2021, gains on all optimization mechanism activities, including short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization undertaken each year will be shared between shareholders and customers. The sharing thresholds are (a) for the first $4.5 million per year, 100 percent of gains to customers; (b) for gains greater than $4.5 million per year and less than $8.0 million per year, split 60 percent to shareholders and 40 percent to customers; and (c) for gains greater than $8.0 million per year, 50-50 sharing between shareholders and customers.

Optimization Mechanism Transactions

Q. Please provide the details of Tampa Electric's short-term wholesale sales under the Optimization Mechanism for 2018.

A. Optimization Mechanism gains from wholesale sales were $2,546,558 or 40 percent of Optimization Gains for 2018. The monthly detail is shown in my exhibit in the schedule "Wholesale Sales-Table 3."

Q. Please provide the details of Tampa Electric's short-term wholesale purchases under the Optimization Mechanism for 2018.

A. Optimization Mechanism gains from wholesales purchases were $2,973,160 or 47 percent of Optimization Gains for 2018. The monthly detail can be found in my exhibit on the schedule labeled "Wholesale Purchases-Table 4."

Q. Please describe Tampa Electric's asset optimization activities and the gains from those transactions under the Optimization Mechanism for 2018.

A. Optimization Mechanism gains from asset optimization activities were $847,539 or 13 percent of Optimization Gains for 2018. The gains from asset optimization activities are shown in my exhibit at “Asset Optimization Detail-Table 5.”

A description of the asset optimization activities in which Tampa Electric engaged during 2018 is provided below.

- Gas storage utilization - release contracted storage space or sell stored gas during non-critical demand seasons;
- Delivered gas sales using existing transport - sell gas to Florida customers, using Tampa Electric's existing gas transportation capacity during periods when it is not needed to serve Tampa Electric's native electric load;
- Delivered solid fuel and or transportation capacity sales using existing transport – sell coal and coal transportation to Florida industrial customers, using Tampa Electric’s existing coal and transportation capacity during periods when it is not needed to serve Tampa Electric’s native electric load;
- Asset Management Agreement ("AMA") - outsource

optimization functions to a third party through assignment of power, transportation and/or storage rights in exchange for a premium to be paid to Tampa Electric.

Q. Please summarize the activities and results of the Optimization Mechanism for 2018.

A. Tampa Electric participated in the following Optimization Mechanism activities in 2018: wholesale power purchases and sales, gas storage utilization, delivered gas sales, delivered solid fuel sales, and natural gas storage AMAs. The Optimization Gains for 2018 were $6,367,256 which exceeded the $4,500,000 threshold by $1,867,256 as shown in my exhibit on schedule “Total Gains Threshold Schedule-Table 1”. Customer benefits were $5,246,902, and company benefits were $1,120,353 in 2018.

Q. Did Tampa Electric incur incremental Optimization Mechanism costs during 2018?

A. Tampa Electric incurred incremental Optimization Mechanism personnel costs to establish processes and manage these new activities. However, the company agreed that it would not seek recovery of these costs if the

Optimization Mechanism was approved and therefore has not tracked the costs.

Q. Overall, were Tampa Electric’s activities under the Optimization Mechanism successful in 2018?

A. Yes, Tampa Electric produced customer gains of $5,246,902 in the first year of Optimization Mechanism activity. The company is also optimistic about increasing future customer gains through continued improvements in processes, reporting, and optimization strategies.

Tampa Electric began 2018 with significant gains on both power and gas activities in January as cold weather provided some optimization opportunities. Wholesale power sales were consistent in most months during the year, while wholesale power purchases increased during typical spring and fall outage seasons when purchased power from the market was less than the cost of the company’s generation. Natural gas storage AMA activity was initiated in 2018, with a short-term trial with one company and then the selection of a longer-term AMA partner following an RFP process.

Despite the success of the program in 2018, without the gains resulting from activities allowed by the very cold weather in January 2018, the gains would be close to the $4,500,000 customer-value threshold, leaving the company with minimal gains relative to the risk incurred to operate the Optimization Mechanism.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

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

A. My name is John C. Heisey. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Trading.

Q. Have you previously filed testimony in Docket No. 20190001-EI?

A. Yes, I submitted direct testimony on March 1, 2019.

Q. Has your job description, education, or professional experience changed since your most recent testimony?

A. No, it has not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies.

Fuel Mix and Procurement Strategies

Q. What fuels do Tampa Electric's generating stations use?

A. Tampa Electric's fuel mix includes natural gas, coal, solar, and, as a backup fuel, oil. Big Bend Units 1 and 2 can operate on natural gas, and Big Bend Units 3 and 4 can operate on coal or natural gas. Polk Unit 1 can operate on a blend of petroleum coke and coal or on natural gas. Currently, the company is operating Big Bend Units 1 through 3 and Polk Unit 1 on natural gas and Big Bend Unit 4 on coal. Polk Unit 2 combined cycle uses natural gas as a primary fuel and oil as a secondary fuel; and Bayside Station combined cycle units and the company's collection of peakers (*i.e.*, aero-derivative combustion turbines) all utilize natural gas. Since it serves as a backup fuel, oil consumption is primarily for testing, and oil is a negligible percentage of system generation. During 2019, continued low natural gas prices equate to lower fuel prices for customers. Based upon the 2019 actual-estimate projections, the company expects 2019 total system generation, excluding purchased power, to be 90 percent natural gas, 6 percent coal, and 4 percent solar.

Likewise, in 2020, natural gas-fired and coal-fired generation are expected to be 89 percent and 4 percent of total generation, respectively, with solar facilities making up 7 percent of total generation.

Q. Please describe Tampa Electric's fuel supply procurement strategy.

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all its fuel needs. The company strives to maintain many credit worthy and viable suppliers. Similarly, the company endeavors to maintain multiple delivery path options. Tampa Electric also attempts to diversify the locations from which its supply is sourced. Having a greater number of fuel supply and delivery options provides increased reliability and flexibility to pursue lower cost options for Tampa Electric customers.

Coal Supply Strategy

Q. Please describe Tampa Electric's solid fuel usage and procurement strategy.

A. The steam turbine units at Big Bend Station are designed to burn high-sulfur Illinois Basin coal and are fully scrubbed for sulfur dioxide and nitrogen oxides, and the units have been upgraded to operate on natural gas. Polk Unit 1 can burn a blend of petroleum coke and low sulfur coal, or natural gas. Each plant has varying operational and environmental restrictions and requires solid fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content, and chlorine content.

Coal is not a homogenous product. The fuel's chemistry and contents vary based on many factors, including geography. The variability of the product dictates Tampa Electric select its fuel based on multiple parameters. Those parameters include unique coal characteristics, price, availability, deliverability, and credit worthiness of the supplier.

To minimize costs, maintain operational flexibility, and ensure reliable supply, Tampa Electric typically maintains a portfolio of bilateral coal supply contracts with varying term lengths. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generation stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market. This market intelligence also helps shape the company’s coal procurement strategy to reflect short- and long-term market conditions. Tampa Electric’s strategy provides a stable supply of reliable fuel sources. In addition, this strategy allows the company the flexibility to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize how Tampa Electric will manage its solid fuel supply contracts through 2020.

A. Since the company is projected to use less coal and more natural gas in 2020 compared to previous years, Tampa Electric will supply the Big Bend and Polk Stations with solid fuel through a combination of existing inventory, short-term contracts and spot purchases. The short-term and spot purchases allow the company to adjust supply to reflect changing coal quality and quantity needs, operational changes, and pricing opportunities.

Coal Transportation

Q. Please describe Tampa Electric’s solid fuel transportation arrangements.

A. Tampa Electric can receive coal at its Big Bend Station via waterborne or rail delivery. Once delivered to Big Bend Station, solid fuel is consumed onsite, or blended and trucked to Polk Station for consumption in Polk Unit 1.

Q. Why does the company maintain multiple coal transportation options in its portfolio?

A. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers various benefits. Those benefits include 1) access to more potential coal suppliers, which results in a more competitively priced, and diverse, delivered coal portfolio; 2) the opportunity to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode; and 3) competition among transporters for future solid fuel transportation contracts.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2019 and 2020?

A. Yes. Tampa Electric expects to receive coal for use at

Big Bend Station through the Big Bend rail facility during 2019 and is evaluating how much coal to receive by rail in 2020.

Q. Please describe Tampa Electric's expectations regarding waterborne coal deliveries.

A. Tampa Electric expects to receive solid fuel supply from waterborne deliveries to its unloading facilities at Big Bend Station. These deliveries come via the Mississippi River System through United Bulk Terminal or from foreign sources. The ultimate supply source is dependent upon quality, operational needs, and lowest overall delivered cost.

Q. Do you have any other updates to provide regarding Tampa Electric's solid fuel transportation portfolio?

A. The continued trend of an abundant volume of natural gas available at historically low prices results in Tampa Electric's continued use of natural gas in the dual-fueled Big Bend and Polk units. In addition, the company's strategy of utilizing short-term and spot solid fuel purchases allows Tampa Electric to reduce its solid fuel deliveries going forward, which aligns well with the economical use of natural gas. As a result, Tampa Electric will contract for fewer tons of solid fuel supply and transportation in the remainder of 2019 and 2020 than in previous years.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2020 solid fuel supply portfolio.

A. Tampa Electric continues to place emphasis on flexibility in its solid fuel supply portfolio. The company recognizes that several factors may impact the annual consumption of solid fuel. These factors include the relative price of delivered solid fuel compared to the delivered natural gas and wholesale power markets. Thus, the actual quantity of solid fuel burned may vary significantly each year. In developing its solid fuel portfolio, Tampa Electric strives to balance the need to have reliable solid fuel commodity supplies and transportation while mitigating the potential for significant shortfall penalties if the commodity or transportation is not needed.

Natural Gas Supply Strategy

Q. How does Tampa Electric's natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long- and short-term deliveries?

A. Like its coal strategy, Tampa Electric uses a portfolio approach to natural gas procurement. This approach consists of a blend of pre-arranged base, intermediate, and swing natural gas supply contracts complemented with shorter term spot and seasonal purchases. The contracts have various time lengths to help secure needed supply at competitive prices and maintain the ability to take advantage of favorable natural gas price movements. Tampa Electric purchases its physical natural gas supply from creditworthy counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indices, further increasing pricing diversification.

Tampa Electric diversifies its pipeline transportation assets, including receipt points. The company also utilizes pipeline and storage services to enhance access to natural gas supply during hurricanes or other events that constrain supply. Such actions improve the reliability and cost-effectiveness of the physical delivery of natural gas to the company's power plants. Furthermore, Tampa Electric strives daily to obtain reliable supplies of natural gas at favorable prices in order to mitigate costs to its customers.

Q. Please describe Tampa Electric's diversified natural gas transportation agreements.

A. Tampa Electric currently receives natural gas via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. Tampa Electric has added the ability to receive a portion of its gas via the recently constructed Sabal Trail Transmission ("Sabal Trail") gas pipeline. The ability to deliver natural gas directly from three pipelines increases the fuel delivery reliability for Bayside Power Station, which is composed of two large natural gas combined-cycle units and four aero-derivative combustion turbines. Natural gas can also be delivered to Big Bend Station from Gulfstream and Sabal Trail (via Gulfstream backhaul) to support the station's steam generating units and aero-derivative combustion turbine. Polk Station receives natural gas from FGT to support Polk Unit 2 and, as an alternate fuel, Polk Unit 1. The addition of Sabal Trail to the company's delivery options enhances reliability, supply, price, and location diversity.

Q. Are there any significant changes to Tampa Electric's expected natural gas usage?

A. Tampa Electric’s natural gas usage is expected to remain stable in 2020. The strategy of burning economical natural gas in dual-fueled units continues to provide lower overall costs to customers.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric maintains natural gas storage capacity with Bay Gas Storage near Mobile, Alabama to provide operational flexibility and reliability of natural gas supply. The company reserves 2,000,000 MMBtu of long-term storage capacity in two locations.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT Zones 1, 2, and 3. Diverse receipt points reduce the company’s vulnerability to hurricane impacts and provide access to potentially lower priced gas supply.

Tampa Electric also reserves capacity on the Southeast Supply Header (“SESH”) and Transco’s Mobile Bay Lateral (“Transco”). SESH and Transco connect the receipt points of FGT, Gulfstream and other Mobile Bay area pipelines with natural gas supply in the mid-continent and northeast. Mid-continent and northeast natural gas production, specifically shale production, has grown and continues to increase. Thus, SESH and Transco capacity give Tampa Electric access to secure, competitively priced onshore gas supply for a portion of its portfolio.

Q. Has Tampa Electric acquired additional natural gas transportation for 2019 and 2020 due to greater use of natural gas?

A. Yes, with the continued low price of natural gas and the company's growing demand for natural gas for electric generation purposes, the company acquires daily, seasonal and longer-term pipeline capacity to support the company's portfolio of gas-fired generation assets. In particular, in 2019, Tampa Electric acquired 20,000 MMBtu per day of additional seasonal pipeline capacity, on Sabal Trail. This capacity provides additional diversification of pipelines and gas supply receipt points.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes, Tampa Electric diligently manages its mix of long-term, intermediate, and short-term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company's fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Q. Have there been other changes in the management of Tampa Electric's fuel supply portfolio?

A. Yes, as part of Tampa Electric's 2017 Amended and Restated Stipulation and Settlement Agreement approved by Commission Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket No. 20170210-EI, Tampa Electric has been operating under an Asset Optimization Mechanism since January 1, 2018. This Optimization Mechanism encourages Tampa Electric to market temporarily unused fuel supply assets to capture cost mitigation benefits for customers. These benefits have come through economic power purchases, economic power sales, resale of unneeded fuel supply, an asset management agreement for natural gas storage, and utilization of natural gas and solid fuel storage and transportation assets.

Projected 2020 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), PIRA Energy, the Energy Information Administration, and other energy market information sources. Future prices for energy commodities as traded on NYMEX, averaged over five consecutive business days in May 2019, form the basis of the natural gas and No. 2 oil market commodity price forecasts. The price projections for these two commodities are then adjusted to incorporate expected transportation costs and location differences.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry recognized consultants and published indices, such as Doyle Trading Consultants and *Coal Daily*. Also, the price projections are specific to the particular quality and mined location of coal utilized by Tampa Electric's Big

Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2020 projected fuel prices compare to the fuel prices projected for 2019 in the company's mid-course correction filing?

A. Large quantities of domestic shale-related production are keeping natural gas prices low. The commodity price for natural gas during 2020 is projected to be lower ($2.77 per MMBtu) than the 2019 price ($3.29 per MMBtu) projected in the company's mid-course correction fuel filing. Coal prices, however, are trending higher. The 2020 coal commodity price projection is slightly higher ($39.52 per ton) than the price projected for 2019 ($37.81 per ton) during preparation of the 2019 mid-course correction fuel clause factors. International demand for coal is elevating coal prices despite minimal domestic demand.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF INTESAR TERKAWI

DOCKET NO. 20190001-EI

SEPTEMBER 13, 2019

Q. Please state your name and business address.

A. My name is Intesar Terkawi. My business address is 1313 N. Tampa Street, Suite 220, Tampa, Florida 33602.

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

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utility Analyst in the Office of Auditing and Performance Analysis. I have been employed by the Commission since October 2001.

Q. Briefly review your educational and professional background.

A. In 1995, I received a Master Degree of Arts with a major in Communications from the University of Central Florida. In 2001, I received a Bachelor of Science Degree from the University of Central Florida with a major in accounting. I am also a Certified Public Accountant.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I filed testimony in the Fuel and Purchased Power Cost Recovery Clause, Docket Nos. 20140001-EI, 20150001-EI, 20160001-EI, 20170001-EI, and 20180001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff auditor's report of Tampa Electric Company (TECO or Utility) which addresses the Utility's filing in Docket No. 20190001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an auditor's report in this docket for the hedging activities on September 6, 2019. This report is filed with my testimony and is identified as Exhibit IT-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared by me.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

We obtained TECO's supporting detail of the hedging settlements for the months of August through November 2018. TECO's hedging activities ceased in November 2018. The supporting documentation was traced to the general ledger transaction detail. We verified that the accounting treatment for hedging transactions and transaction costs is consistent with Commission orders relating to hedging activities. The Utility did not enter into any new contracts between August 1, 2018 and July 31, 2019. No exceptions were noted.

Gains and Losses

We traced the monthly balances of hedging transactions from TECO's Hedging Information Report to its Mark to Market Position Report for the period August 1, 2018, to November 30, 2018. We selected all gas hedging transactions for August through November 2018 and traced them from the Mark to Market Position Report to the third-party confirmation notices and contracts. We traced a sample of the purchase prices to the Gas Daily – NYMEX Henry Hub gas futures contract rates. We traced the related settlements prices to the Gas Daily – NYMEX Henry Hub gas futures contract rate. We recalculated the gains and losses and traced them to the Utility's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

We reviewed the quantity limits and authorizations. We also obtained TECO's analysis of the monthly percent of fuel hedged in relation to fuel burned for August through November 2018, and compared them to the Utility's 2016 Risk Management Plan. No exceptions were noted.

Separation of Duties

We reviewed TECO's written procedures for separation of duties related to hedging activities. There were no internal or external audits related to hedging activities. No exceptions were noted.

Q. Please review the audit findings in this report.

A. There were no findings in this audit related to hedging activities.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF SIMON O. OJADA

DOCKET NO. 20190001-EI

SEPTEMBER 13, 2019

Q. Please state your name and business address.

A. My name is Simon O. Ojada. My business address is 1313 N. Tampa Street, Suite 220, Tampa, Florida 33602.

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

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utility Analyst in the Office of Auditing and Performance Analysis. I have been employed by the Commission since April 1997.

Q. Briefly review your educational and professional background.

A. I received a Bachelor of Science degree from the University of South Florida with a major in Finance in 1991, a Bachelor of Science Degree from Florida Metropolitan University with a major in Accounting in 1994, and a Master of Business Administration with a concentration in Accounting in 1997.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I filed testimony in the Fuel and Purchased Power Cost Recovery Clause, Docket Nos. 20130001-EI, 20140001-EI, 20150001-EI, 20160001-EI, 20170001-EI, and 20180001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff auditor's report of Duke Energy Florida, LLC (DEF or Utility) which addresses the Utility's filing in Docket No. 20190001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an auditor's report in this docket for the hedging activities on September 3, 2019. This report is filed with my testimony and is identified as Exhibit SOO-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared by me.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

<u>Accounting Treatment</u>

We obtained DEF's supporting detail of the hedging settlements for the 12 months ended July 31, 2019. The support documentation was reconciled to the general ledger transaction detail. We verified that the accounting treatment for hedging transactions and transaction costs is consistent with Commission orders relating to hedging activities. The Utility did not enter into any new contracts between August 1, 2018 and July 31, 2019. No exceptions were noted.

<u>Gains and Losses</u>

We reconciled the monthly balances of hedging transactions from DEF's Hedging Details Report for the period August 1, 2018, through July 31, 2019, to its Hedging Summary by Commodity Reports for 2018 and 2019. DEF completed its outstanding hedging transaction settlements as of March 31, 2019.We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We selected 20 natural gas hedging transactions from September 2018 through December 2018 as a sample. We reconciled the selected samples from the Hedging Details Report to the third-party confirmation notices and contracts. We reconciled the gains and losses to the Utility's journal entries. We compared the price on the confirmation notice to the price published by the NYMEX Henry Hub gas futures contract rates. No exceptions were noted.

Hedged Volume and Limits

We reviewed the quantity limits and authorizations for all hedged fuel types in compliance with the 2016 Risk Management Plan. No exceptions were noted.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. We reviewed the Utility Audit Services Department's evaluations for the 12 months ending December 31, 2018, for the Regulated Fuels Inventory Management Process and the Regulated Trading Cycle. There were no external or internal audits on hedging activities during the test period. No exceptions were noted.

Q. Please review the audit findings in this report.

A. There were no findings in this audit related to hedging activities.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF DEBRA DOBIAC

DOCKET NO. 20190001-EI

SEPTEMBER 13, 2019

Q. Please state your name and business address.

A. My name is Debra M. Dobiac. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399.

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

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utility Analyst in the Office of Auditing and Performance Analysis. I have been employed by the Commission since January 2008.

Q. Briefly review your educational and professional background.

A. I graduated with honors from Lakeland College in 1993 and have a Bachelor of Arts degree in accounting. Prior to my work at the Commission, I worked for six years in internal auditing at the Kohler Company and First American Title Insurance Company. I also have approximately 12 years of experience as an accounting manager and controller.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I testified in the Aqua Utilities Florida, Inc. Rate Case, Docket No. 20080121-WS, the Water Management Services, Inc. Rate Case, Docket No. 20110200-WU, and the Utilities, Inc. of Florida Rate Case, Docket No. 20160101-WS. I also provided testimony for the Water Management Services, Inc. Rate Case, Docket No. 20100104-WU, the Gulf Power Company Rate Cases, Docket Nos. 20110138-EI and 20130140-EI, and the Gulf Power Company Hedging Activities, Docket Nos. 20130001-EI, 20140001-EI, the Florida Power & Light Company Hedging Activities, Docket No. 20180001-EI, and the Florida Public Utilities Company's petition for limited proceeding to recover incremental storm restoration costs, Docket No. 20180061-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff auditor's report of Gulf Power Company (Gulf or Utility) which addresses the Utility's filing in Docket No. 20190001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an auditor's report in this docket for the hedging activities on August 28, 2019. This report is filed with my testimony and is identified as Exhibit DMD-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared by me.

Q. Please describe the work you performed in this audit.

A. I have separated the audit work into several categories.

<u>Accounting Treatment</u>

We obtained Gulf's supporting detail of the hedging settlements for the twelve months ended July 31, 2019. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. The Utility did not enter into any new contracts between August 1, 2018 and July 31, 2019. Gulf's hedging program is expected to be completed in the first quarter of 2020. No exceptions were noted.

<u>Gains and Losses</u>

We traced the monthly balances of all hedging transactions from Gulf's Hedging Information Reports to its settlement report and its general ledger for the period August 1, 2018 to July 31, 2019. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the settlement statement details, and compared the price to the gas futures rates published by the New York Mercantile Exchange (NYMEX) Henry Hub Gas futures contract rates. We compared these recalculated gains and losses with Gulf's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

We reviewed the quantity limits and authorizations. We also obtained GPC's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the twelve months ended July 31, 2019, and compared them with the Utility's 2016 Risk Management Plan. No exceptions were noted.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. We note that as of January 1, 2019, all hedges outstanding were transferred to NextEra/FPL and it will oversee the settling of the remaining hedges. There were no internal or external audits specifically performed on the separation of duties related to hedging activities. No exceptions were noted.

Q. Please review the audit findings in this report.

A. There were no findings in this audit related to hedging activities.

Q. Does that conclude your testimony?

A. Yes.

MS. BROWNLESS: Due to the fact that Issue 1B and 1C, excuse me, have been sent to DOAH for hearing, the prefiled testimonies of Jeffery Swartz and Richard A. Polich have not been included in this list.

CHAIRMAN GRAHAM: All right. So exhibits.

MS. BROWNLESS: Yes, sir.

Staff has compiled a stipulated comprehensive exhibit list, which includes the prefiled exhibits attached to the witness' testimony as well as Staff's Exhibit 83 through 99. The list has been provided to the parties, the Commissioners and the court reporter.

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

(Whereupon, Exhibit No. 1 was marked for identification.)

(Whereupon, Exhibit Nos. 83-99 were marked for identification.)

CHAIRMAN GRAHAM: All right. So let's move exhibits.

MS. BROWNLESS: Okay. And we've asked that the Exhibit No. 1 be entered into the record, sir.

CHAIRMAN GRAHAM: We will enter Exhibit 1 into the record.

MS. BROWNLESS: Thank you.

(Whereupon, Exhibit No. 1 was received into evidence.)

MS. BROWNLESS: And we would request that the stipulated staff exhibits, Nos. 83 through 99, be entered into the record.

CHAIRMAN GRAHAM: If there is no -- if nobody is against entering 83 through 99 into the record, we will enter those into the record as well.

(Whereupon, Exhibit Nos. 83-99 were received into evidence.)

MS. BROWNLESS: We will note that the exhibits of Jeffery Swartz, Exhibits 8, 80, 81, 82 and 100, and the exhibits of Richard Polich, Exhibits 68 through 76, have been included in the CEL but will not be moved into the record at this hearing due to the referral of Issues 1B and 1C to DOAH.

Exhibits that have been agreed to the parties -- to by the parties are Exhibits No. 2 through 7, 9 through 67 and 77 through 79.

CHAIRMAN GRAHAM: So the parties have reviewed the exhibit list, if there is any objections. I take it no?

Okay. Opening statements -- oh, prehearing officer, you just lost a couple of steps. What's with this five minutes?

Have any parties -- if any of the parties wish to give an opening statement, you will be allowed to give -- okay, are we doing opening statements now?

MS. BROWNLESS: Yes, sir.

CHAIRMAN GRAHAM: Okay. Opening statements. Florida Power & Light.

MS. MONCADA: Good afternoon again, Chairman Graham and Commissioners.

I understand that FIPUG contests Issue 2H, which is the only reason I am taking five minutes to give an opening statement this afternoon, but thank you for the opportunity to present some remarks regarding FPL's petition for approval of its 2020 solar base rate adjustment known as the SoBRA.

FPL requests approval for the last of its solar projects being constructed through the SoBRA mechanism that was approved under FPL's current rate settlement. The 2020 SoBRA project will provide nearly 300 megawatts of clean, cost-effective solar power to serve our customers and is projected to provide substantial cost savings over the long-term.

Under the settlement order FPL is authorized to recover the project's revenue requirements so long as it satisfies specific requirements.

First, the solar project must be cost-effective.

Second, the total cost cannot exceed $1,750 per kilowatt.

And third, the cost for the construction, engineering and the components must be reasonable.

These issues, along with the calculation of the revenue requirement and the SoBRA factor, are the sole issues for determination in evaluating whether to allow cost recovery. And as recently as this summer, the Florida Supreme Court announced and settled that this is the standard that governs as to all parties regardless of whether they supported the settlement at the time it was submitted for your approval back in 2016. The question of need is not at issue here.

The testimony of FPL witness Juan Enjamio demonstrates that the 2020 project is, in fact, cost-effective. The generation resource plan that includes the 2020 project saves customers $26 million compared to a status quo plan that excludes the 2020 project. This means significant savings for FPL's customers derived mainly from fuel savings also includes reduced emissions, and this is not to mention the creation of new jobs and all of the tax revenue that the projects will create and provide to local communities.

On a stand-alone basis, the 2020 project will produce enough electricity to power the equivalent of approximately 58,000 homes. And when we look at this project in conjunction with the SoBRAs already operational throughout our territory, the SoBRA projects produce enough generation to power the equivalent of at least 232,000 homes annually, and the avoided emissions are the equivalent of reducing more than 215,000 cars from the road annually.

In terms of savings, all of the solar projects under the SoBRA mechanism collectively have been projected to save FPL customers $172 million.

Mr. Brannen's testimony demonstrates that the 2020 project's costs are significantly below the 1,750 cost cap. As Mr. Brannen explains, FPL ensured that the costs are reasonable by using a very thorough and comprehensive solicitation process that went to not only the procurement of the major equipment, but also with respect to the engineering and the construction costs for the projects.

FPL witnesses Fuentes and Anderson provide the calculation of the revenue requirement and the resulting SoBRA -- SoBRA factor for the 2020 project, and did so consistent with the directives in the rate settlement order.

So, Commissioners, in short, FPL's 2020 project is cost-effective, and it reflects reasonable construction costs that do not exceed the cost cap of $1,750 per kilowatt, and FPL requests approval of its petition.

Thank you.

CHAIRMAN GRAHAM: Thank you.

Mr. Moyle.

MR. MOYLE: Thank you.

And we did want to just take this opportunity to provide some comments to you about the SoBRA, and it is the first time the SoBRA has been back before you after the Court considered arguments and issued its ruling, and Maria brought that up.

And really what I want to do today is just share some broader thoughts. It's a day of transition for you. And not unlike your discussion on FEECA and where that goes, I want to just spend a few minutes and talk about -- about solar.

A quick little footnote, we took the position in the prehearing to say, burden of proof, you have to make -- you have to show your -- your -- carry your burden, as Mr. Rubin was saying, we got to carry our burden. And we were saying, no, you got to do more than that.

So to put it at issue, we said no, but for the record, it's a no with a small N, and really we wanted to -- wanted to use this opportunity to really just raise some issues as you look at solar going, you know, going forward, and in the context of the SoBRA.

So I have appeared before you a number of times and said, my client, the Florida Industrial Power Users Group, FIPUG, with respect to solar, we support renewable energy so long as it satisfies two things. It needs to be cost-effective and it must be needed, okay.

And you all have -- have broad prudence determinations that you ordinarily can make. Well, you can't -- you can't make them here, because as -- as was indicated, your purview is greatly limited here. There is three things that you consider. You know, cost-effectiveness is one thing you consider.

And we are a big fan of cost-effectiveness, you know, in a market context. I mean, you have RFPs and different things. And while some of the components were -- were bid, you know, all of these SoBRAs at 74 megawatts, they don't go through a rigorous competitive process where others are bidding on them.

And then the other thing with respect to cost-effectiveness, it's measured by a number in a settlement agreement.

FIPUG did not sign that settlement agreement and, you know, when it was entered and executed, really, the inter-- the intervenors are not experts in solar, and so there was a number that was put out there that I used the analogy to say it's kind of like putting a requirement in a document that says: It's presumed cost-effective any house in Tallahassee if it's under $1 million. Now, those who live in Tallahassee know that you can do a lot of house for less than $1 million, but so long as you are under $1 million, the agreement says it's cost-effective by the -- by the terms of the agreement.

So your job today is so long as it's under that number, you know, you have to say it's good to go. And I would suggest that that's probably not, in a big picture, the best way to deal with solar moving forward. You have a lot of SoBRAs. You have a lot of people wanting to do solar. And, again, we support it, provided it meets those two requirements of need and cost-effectiveness, but, you know, there is no need determination. So are you putting solar on top of, you know, 50 percent reserve margins? At some point, you kind of go, like, yeah, this may be okay, but why don't you wait a few years to do this.

So as we move forward with solar, we will continue to stay involved and engaged, but we would encourage you, as the Commission, to consider casting maybe a broader view rather -- when you are able to, and you are not able to today because you have a SoBRA in front of you, but take a holistic look at it.

And I remember discussions about natural gas plants, and FIPUG would intervene in some of the natural gas proceedings. And we had asked questions and said, at some point when is too much? I mean, when do you have too much natural gas? And I think a similar question could be asked of solar at some point.

Commissioner Clark, you, throughout the course of some discussions, have said, well, it doesn't work that great at night, and there is, you know, some benefits to having generation that is maybe a little more dependable and reliable.

There is a place for solar, and we support it, but I just wanted to use this occasion, because it is the first occasion where we can address you all after the Supreme Court has ruled and -- and -- and present that as kind of as you move forward directionally that I think it would be important to take a wider view of solar and, when able to do so, consider things like need and cost-effectiveness considering market conditions in a more robust way.

So those are the comments I wanted to make. Thank you.

CHAIRMAN GRAHAM: Five minutes and one second.

MR. MOYLE: I am sorry?

CHAIRMAN GRAHAM: I said five minutes and one second.

Okay. OPC, did you have any comments?

All right. Decision on the stipulated issues.

MS. BROWNLESS: Yes, sir.

The first set are the Type 2 stipulations, and these are 1A, 2A, 2B through 2G, 2I through 2N, 4A, 5A, 5B, 6 through 11, 16 through 22 -- 16 through 21, 22 as amended with the DEF corrections, 23A, 23B, 24A through 24D, 27 through 36 as listed on pages 29 through 61 of the prehearing order.

Also, Issue No. 37, should this docket be closed? As I understand it, the parties have now entered into a Type 2 stipulation for this issue and the stipulation states:

No. While a separate docket number is assigned each year for administrative convenience, this is a continuing docket and should remain open.

At this time, we would request a bench decision on these issues, and staff is available to answer questions.

CHAIRMAN GRAHAM: Commissioners, it is time for you to ask staff any questions and to reprimand the prehearing officer for his five minutes opening statements.

COMMISSIONER POLMANN: Mr. Chairman, I would commend the outstanding work of the esteemed Commissioner Clark and look forward to additional future four minutes per party with limitations. I believe I have achieved three minutes in the past, and I challenge you.

And having said that, Mr. Chairman and Commissioners, I would move approval of this Type 2 stipulations that Ms. Brownless has read into the record without repeating them. I think they have all been enumerated.

CHAIRMAN GRAHAM: It's been moved and seconded.

Commissioner Brown.

COMMISSIONER BROWN: Thank you.

I just wanted to say I appreciate the comments very -- very poignant, very well taken that you raised today on need and cost-effectiveness with regard to solar. So just thank you for coming out here and sending that message, and look forward to seeing you at future dockets.

CHAIRMAN GRAHAM: Commissioner Clark.

COMMISSIONER CLARK: Thank you, Mr. Chairman.

I want to just take a moment and thank everyone in all of the clause dockets for the hard work.

Staff did a fantastic job of organizing and getting us to the point where we were able to -- I probably would have to say set a record, 35 minutes for five clause hearings, and that's with two five-minute opening statements.

So you have to give a little to get a little bit, Mr. Chairman --

CHAIRMAN GRAHAM: I understand.

COMMISSIONER CLARK: -- and I was working to negotiate us down to a lot of stipulations.

So I do thank all of the parties that are involved for your cooperation and the work that you did to getting us to this.

This was a really, really good process for me personally, working through this with each of you, and you are all to be commended. Thank you for your hard work.

COMMISSIONER BROWN: Good job.

COMMISSIONER CLARK: Thank you.

CHAIRMAN GRAHAM: We have a motion, duly seconded before us.

Any further discussion?

Seeing none, all in favor say aye.

(Chorus of ayes.)

CHAIRMAN GRAHAM: Any opposed?

(No response.)

CHAIRMAN GRAHAM: By your action, you have approved the Polmann motion.

Now we have a decision on Issue 2H.

MS. BROWNLESS: Yes, sir.

Issue 2H are the 2020 SoBRA projects, Hibiscus, Okeechobee, Southfork and Echo River proposed by FPL cost-effective.

This issue has been contested by FIPUG. Mr. Moyle has addressed this in his opening statement, as has Ms. Moncada. My understanding is that neither party wishes to brief this issue, and staff is available to answer questions and requests a bench decision.

CHAIRMAN GRAHAM: Commissioners, now is the time to speak about Issue 2H.

Commissioner Fay.

COMMISSIONER FAY: Thank you, Mr. Chairman. I would move for the approval of Issue 2H.

COMMISSIONER BROWN: Second.

CHAIRMAN GRAHAM: It's been moved and seconded.

Any further discussion on Issue 2H?

Seeing none, all in favor say aye.

(Chorus of ayes.)

CHAIRMAN GRAHAM: Any opposed?

(No response.)

CHAIRMAN GRAHAM: By your action, you have approved Issue 2H.

Before I move on to witness testimony, evidently I forgot to enter Exhibits 2 through 7, 9 through 67, 77 through 79. If there is no objections to those, we will enter those into the record.

(Whereupon, Exhibit Nos. 2-7, 9-67, 77-79 were received into evidence.)

CHAIRMAN GRAHAM: Okay. Witness testimony.

MS. BROWNLESS: Thank you.

All witnesses have been stipulated to and their testimony and exhibits moved into the record with the exception of witnesses Swartz and Polich, who will testify at the DOAH hearing.

CHAIRMAN GRAHAM: Okay. Concluding the hearing.

MS. BROWNLESS: At this time, all issues have been voted upon with the exception of Issues 1B and 1C, which will be heard later at DOAH.

Since all issues heard in this docket have been stipulated to, ruled on or deferred, there is no need for briefs or further Commission action to resolve the issues before us today. An order will be issued on or before November 25th of 2019.

CHAIRMAN GRAHAM: Any other matters to come before us on this docket?

I do want to thank you guys all for all these stipulations that came before us. And for handling most of this stuff on your own with the prehearing officer. All kidding aside, I think the prehearing officer did a fantastic job on this -- the clause docket, so on this docket.

I do thank you all for your patience today. It's been a long day. I am sure everybody is ready to call it a day.

The question I have of General Counsel, when we list things that are -- one item is going to follow the other on our -- on our calendar, is it possible to move things around, or are we stuck with that order just because that's the way it was noticed?

You don't have to answer that question now, but in the future, because it would have been nice to be able to take this up first before we got to some of that other stuff, so these guys could have moved on, and then we could have taken up IA and then we could have dealt with Agenda. But I just want to put that before you for some thought to see how we can, in the future, when we notice meetings that we have that flexibility to move things around.

MR. HETRICK: We will take that under advisement and get back with you, Mr. Chair.

CHAIRMAN GRAHAM: Okay. Once again, thank you all. Everybody please travel safe.

I think I will see you guys next month. I won't see you so a Happy Thanksgiving to all you guys.

(Proceedings concluded at 4:37 p.m.)

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 14th day of November, 2019.

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