BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20170001-EI

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

VOLUME 2
PAGES 212 - 441

PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN JULIE I. BROWN COMMISSIONER ART GRAHAM COMMISSIONER RONALD A. BRISÉ COMMISSIONER DONALD J. POLMANN COMMISSIONER GARY F. CLARK
DATE:	Wednesday, October 25, 2017
TIME:	Commenced at 12:30 p.m. Concluded at 2:00 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	DEBRA R. KRICK Court Reporter
APPEARANCES:	(As heretofore noted.)

PREMIER REPORTING
114 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
(850) 894-0828

I N D E X

WITNESSES

NAME:	PAGE
Shane Boyett prefiled testimony inserted	216
Cody Nicholson prefiled testimony inserted	268
Penelope Rusk prefiled testimony inserted	277
Brian Buckley prefiled testimony inserted	306
Benjamin Smith prefiled testimony inserted	332
Brent Caldwell prefiled testimony inserted	342
Simon Ojada prefiled testimony inserted	376
Donna Brown prefiled testimony inserted	379
George Simmons prefiled testimony inserted	382
Intesar Terkawi prefiled testimony inserted	385
JUAN ENJAMIO	
Examination by Mr. Cox	420
Corrected prefiled testimony inserted	423
August 2, 2017 prefiled testimony inserted	433

EXHIBITS

NUMBER:		ID	ADMTD
1	Comprehensive Exhibit List	388	389
1-99	As identified in the comprehensive exhibit list	388	
2-27	As identified on the comprehensive exhibit list		389
45-77	As identified on the comprehensive exhibit list		389
78-99	As identified on the comprehensive exhibit list		390

P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

(Whereupon, prefiled testimony was inserted.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibits of
C. Shane Boyett
Docket No. 170001-EI
Date of Filing: March 1, 2017

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 and Cost Recovery Supervisor 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 Gainesville, Florida in 2001 with a Bachelor of Science degree in Business Administration. I also hold a Master of Business Administration degree from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist where I worked for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power's Financial Planning department as a Financial Analyst where I worked until being promoted to my current position of Regulatory and Cost Recovery Supervisor. My responsibilities include oversight of the Company's fuel 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 actual true-up amounts for the period January 2016 through December 2016 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, and purchased power capacity costs, and to certify that these expenses were properly incurred during the period January 1, 2016 through December 31, 2016. Lastly, I will also present the actual benchmark level for the calendar year 2017 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 2016 through December 2016.

Q. Have you prepared any exhibits to which you will refer in your testimony?
A. Yes, I am sponsoring 3 exhibits.
My first exhibit consists of 1 schedule that relates to the fuel and purchased power cost recovery actual true-up and 4 schedules that relate to the capacity cost recovery actual true-up. Exhibit 2 contains Schedules A-1 through A-9 and A-12 for the period December 2016, previously filed with this Commission. My third exhibit consist of 4 schedules that relate to coal suppliers for 2016, heat value and weighted average price for the coal suppliers, Gulf's natural gas purchase price variance for 2016 and hedging effectiveness for 2016.

Counsel: We ask that Mr. Boyett's exhibits be marked as Exhibit No. _____(CSB-1), ______(CSB-2) and _____(CSB-3).

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

A. Yes.

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

A. Schedule 1 of my Exhibit CSB-1 relates to the fuel and purchased power cost recovery true-up calculation for the period January 2016 through December 2016. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for December 2016 are incorporated herein in Exhibit CSB-2.

Q. What is the actual fuel and purchased power cost true-up amount related to the period of January 2016 through December 2016 to be addressed through the fuel cost recovery factors in the period January 2018 through December 2018?

A. A net amount to be collected of $10,797,411 was calculated as shown on Schedule 1 of my Exhibit CSB-1.

Q. How was this amount calculated?

A. The $10,797,411 was calculated by taking the difference between the estimated and actual over/under-recovery amounts for the period January

2016 through December 2016. The estimated over-recovery was $27,383,731 (as shown on Schedule E-1B, Line 6 + 7 + 8) filed August 4, 2016. The actual over-recovery was $16,586,321 which is the sum of the Period-to-Date amounts on lines 7, 8, and 12 shown on the December 2016 Schedule A-2, page 2 of 3, included in CSB-2. Additional details supporting the approved estimated true-up amount are included on Schedules E1-A and E1-B filed August 4, 2016 in Docket No. 160001-EI.

Q. Please explain the adjustments totaling ($253,686.41) shown on December Schedule A-2 for 2016.

A. There are two adjustments that made up the total ($253,686.41) shown on Schedule A-2 for 2016. The first adjustment of ($75,803.69) to the over-recovery balance was a result of an error discovered by Commission audit staff during the 2016 fuel clause audit related to for Gains on Economy Sales. The adjustment, including interest, corrected all months during the period 2015 and was included in the Company's March 2016 monthly fuel filing. The second adjustment for ($177,882.72) to the over-recovery balance represents the annual impact on the fuel clause for the inclusion of Scherer Unit 3 as a retail generating asset for the period January 2016 through December 2016.

Q. During the period January 2016 through December 2016, how did Gulf Power Company's recoverable total fuel and net power transaction expenses compare with the projected expenses?

A. Gulf's recoverable total fuel cost and net power transaction expense was $414,985,585 which is $1,111,368 or 0.27% below the projected amount of $416,096,953. Actual net power transaction energy was 12,014,687,293 kWh compared to the projected net energy of 11,896,128,000 kWh or 1.00% above projections. The resulting actual average cost of 3.4540 cents per kWh was 1.25% below the projected cost of 3.4978 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2016 included in my Exhibit CSB-2. The lower total fuel and net power transaction expense is attributed to a lower per unit cost (cents per kWh) for available energy than projected for the period. The actual total cost of available energy was below projections by $2,015,390 or 0.42% and the total quantity of available energy was above projections by 2,547,046,584 kWh or 17.22%. The actual cost per kWh of available energy was 2.784 cents per kWh which is 15.05% lower than the projected cost of 3.277 cents per kWh. The lower cost per kWh for available energy is due primarily to the mix of available energy containing a higher percentage of purchased power. These energy purchases were primarily from lower cost gas fired generating units that Gulf has secured under Purchase Power Agreements (PPAs).

Q. During the period January 2016 through December 2016, how did Gulf Power Company's recoverable fuel cost of net generation compare with the projected expenses?

A. Gulf's recoverable fuel cost of system net generation was $234,983,070 or 8.10% below the projected amount of $255,692,351. Actual generation was 7,263,317,000 kWh compared to the projected generation of 7,643,508,000 kWh, or 4.97% below projections. The resulting actual average fuel cost of 3.235 cents per kWh was 3.29% below the projected fuel cost of 3.345 cents per kWh. The lower total fuel expense is attributed to the quantity of kWh generated being lower than projected for the period combined with a lower cost per unit for fuel. The actual quantity of fuel consumed was 67,534,776 MMBtu which is 0.72% below the projected quantity of 68,022,213 MMBtu. The percentage of energy generated from coal fired resources was 50.96%, which was 3.43% lower than the projected percentage of 52.77%. The weighted average fuel cost for natural gas was 2.48 cents per kWh, which is 20.00% below the projected cost of 3.10 cents per kWh. The weighted average fuel cost for coal, plus lighter fuel, was 3.95 cents per kWh, which is 10.96% higher than the projected cost of 3.56 cents per kWh. This information is found on Schedule A-3, period-to-date, for the month of December 2016 included in my Exhibit CSB-2.

Q. How did the total projected cost of coal purchased compare with the actual cost?

A. The total actual cost of coal purchased was $124,268,853 (line 17 of Schedule A-5, period-to-date, for December 2016) compared to the projected cost of $117,853,252 or 5.44% above the projected amount. The higher total coal cost was due to the actual quantity of coal purchased being 2.63% higher than projected combined with the weighted average price of coal purchased being $71.24 per ton which is 2.74% above the projected price of $69.34 per ton.

Q How did the total projected cost of coal burned compare to the actual cost?

A. The total cost of coal burned was $141,817,746 (line 21 of Schedule A-5, period-to-date, for December 2016). This is 12.59% higher than the projection of $125,958,221. The higher total coal burn cost was due to the quantity of coal burned being 13.70% above projections offset somewhat by the actual weighted average coal burn cost being $74.28 per ton which is 0.97% below the projected burn cost of $75.01 per ton for the period.

Q. How did the total projected cost of natural gas burned compare to the actual cost?

A. The total actual cost of natural gas burned for generation was $88,911,127 (line 34 of Schedule A-5, period-to-date, for December 2016). This is 19.41% below the projection of $110,325,621. The lower total gas cost was due to the actual weighted average gas burn cost being

$3.48 per MMBtu, which is 22.49% lower than the projected burn cost of $4.49 per MMBtu.

Q. During the period January 2016 through December 2016 how did Gulf Power Company's recoverable fuel cost of power sold compare with the projection?

A. Gulf's recoverable fuel cost of power sold for the period is ($67,647,977) or 1.32% below the projected amount of ($68,552,000). Total quantity of power sales were (5,321,324,291) kWh compared to Gulf's projected sales of (2,892,837,000) kWh, or 83.95% above projections. The resulting average fuel cost of power sold was 1.2713 cents per kWh or 46.35% below the projected amount of 2.3697 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2016 included in my Exhibit CSB-2.

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

A. The lower total credit to fuel expense from power sales is attributed to the lower than projected fuel reimbursement rate (cents per kWh) paid to Gulf for typical power sales. The more favorable position of Gulf's generating assets in system economic dispatch to serve load resulted in a greater quantity of energy sales.

Q. Has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2016 gains?

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

Year	Actual Gain
2014	1,319,633
2015	674,392
2016	700,065
Three-Year Average	$ 872,163

Q. What is the actual threshold for 2017?

A. The actual threshold for 2017 is $872,163

Q. During the period January 2016 through December 2016, how did Gulf Power Company's recoverable fuel cost of purchased power compare to projected cost?

A. Gulf's recoverable fuel cost of purchased power for the period was $193,576,598 or 6.89% below the estimated amount of $207,910,000. Total kilowatt hours of purchased power were 10,072,694,584 kWh compared to the estimate of 7,145,457,000 kWh or 40.97% above projections. The resulting average fuel cost of purchased power was 1.9218 cents per kWh or 33.95% below the estimated amount of 2.9097 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2016 included in my Exhibit CSB-2.

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

A. The lower total fuel cost of purchased power is attributed to Gulf purchasing energy at attractive prices to supplement its own generation to meet load demands. This includes energy supplied to Gulf through purchase power agreements. The average fuel cost of energy purchases per kWh was lower than projected as a result of lower-cost energy being made available to Gulf for purchase during the period.

Q. Should Gulf's recoverable fuel and purchased power cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that supply is available during times when gas supply is otherwise curtailed or unavailable. Gulf's lighter oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf adhered to its

Risk Management Plan for Fuel Procurement and accomplished the objectives established by the plan. Through its participation in the integrated Southern electric system, Gulf is able to purchase affordable energy from pool participants and other sellers of energy when needed to meet load and during times when the cost of purchased power is lower than energy that could be generated internally. Gulf is also able to sell energy to the pool when excess generation is available and return the benefits of these sales to the customer. These energy purchases and sales are governed by the IIC which is approved by the Federal Energy Regulatory Commission (FERC). Gulf also purchases power when economically attractive under the terms of external purchase power agreements which have been reviewed and approved by the Commission.

Q. Did fuel procurement activity during the period in question follow Gulf Power's Risk Management Plan for Fuel Procurement?

A. Yes. Gulf Power's fuel strategy in 2016 complied with the Risk Management Plan filed on August 4, 2015 in Docket No. 150001-EI.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in a reliable supply of coal being delivered to Gulf's coal-fired generating units during the period?

A. Yes. The supply of coal and associated transportation to Gulf's generating plants is generally secured through a combination of long-term contracts and spot agreements as specified in the plan. These supply and transportation agreements included a number of purchase commitments initiated prior to the beginning of the period. These early purchase commitments and the planned diversity of fuel suppliers are designed to provide a more reliable source of coal to the generating plants. The result was that Gulf's coal-fired generating units had an adequate supply of fuel available at all times at a reasonable cost to meet the electric generation demands of its customers.

Q. For coal shipments during the period, what percentage was purchased on the spot market and what percentage was purchased using longer-term contracts?

A. As shown in Schedule 1 of my Exhibit CSB-3, total coal shipments for the period amounted to 1,763,846 tons. Gulf purchased 68.3% of this coal on the spot market. Spot purchases are classified as coal purchase agreements with terms of one year or less. Spot coal purchases are typically needed to allow a portion of the purchase quantity commitments to be adjusted in response to changes in coal burn that may occur during the year due either to economic or operational reasons. Gulf purchased 31.7% of its 2016 coal supply under longer-term contracts. Longer-term contracts provide a reliable base quantity of coal to Gulf's generating units with firm pricing terms. This limits price volatility and increases coal supply consistency over the term of the agreements. Schedule 1 of my Exhibit CSB-3 consists of a list of contract and spot coal shipments to Gulf's generating plants for the period as reported on the monthly FPSC 423 reports.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in stable coal prices for the period?

A. Yes. Coal price volatility was mitigated through compliance with the Risk Management Plan. Gulf uses physical hedges to reduce the price volatility of its coal procurement program. Gulf purchases coal and associated transportation at market price through the process of either issuing formal requests for proposals to market participants or occasionally for small quantity spot purchases through informal proposals. Once these confidential bids are received, they are evaluated against other similar proposals using standard contract terms and conditions. The least cost acceptable alternatives are selected and firm purchase agreements are negotiated with the successful bidders. Gulf purchased coal and coal transportation using a combination of firm price contracts and purchase orders that either fix the price for the period or escalate the price using a combination of government published economic indices. Schedule 2 of Exhibit CSB-3 provides a list of the contract and spot coal shipments for the period and the weighted average price of shipments under each purchase agreement in $/MMBtu. Because of the mix of longer-term contract coal purchase agreements and spot purchase agreements during the period, Gulf was able to take advantage of lower market pricing for spot coal. The variance between the estimated purchase price of coal and the actual price for the period was 2.74% above projected as reported on line 16 of Schedule A-5, period to date, for the month of December 2016.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in a reliable supply of natural gas being delivered to Gulf's gas-fired generating units at a reasonable price during the period?

A. Yes. The supply of natural gas and associated transportation to Gulf's generating plants was secured through a combination of long-term purchase contracts and daily gas purchases as specified in the plan. These supply and transportation agreements included a number of purchase commitments initiated prior to the beginning of the period. These natural gas purchase agreements price the supply of gas at market price as defined by published market indices. Schedule 3 of Exhibit CSB-3 compares the actual monthly weighted average purchase price of natural gas delivered to Gulf's generating units to a market price based on the daily Florida Gas Transmission Zone 3 published market price. The purpose of early natural gas procurement commitments, the planned diversity of natural gas suppliers, and providing gas suppliers with market pricing is to provide a more reliable source of gas to Gulf's generating units. The result was that Gulf's gas-fired generating units had an adequate supply of fuel available at all times at a reasonable price to meet the electric generation demands of its customers.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in lower volatility of natural gas prices for the period?

A. Yes. Gulf purchases physical natural gas requirements at market prices and swaps the market price on a percentage of these purchases for firm prices using financial hedges. The objective of the financial hedging program is to reduce upside price risk to Gulf's customers in a volatile price market for natural gas. In 2016, Gulf's weighted average cost of natural gas purchases for generation was $3.53 per MMBtu. This was 21.38% lower than the projection of $4.49 per MMBtu (line 29 of Schedule A-5, period-to-date, for December 2016). The volatility of Gulf's natural gas cost has been reduced by utilizing financial hedging as described in the Fuel Risk Management Plan. As shown on Schedule 4 of my Exhibit CSB-3, the calculated volatility of Gulf's delivered cost of natural gas for the Smith 3 and Central Alabama PPA combined cycle generating units for the period is represented by a variance of 0.33 and standard deviation of 0.58. The calculation of the volatility of Gulf's hedged delivered cost of natural gas for the period yields a variance of 0.24 and standard deviation of 0.49. The lower variance and standard deviation for hedged cost of natural gas continues to demonstrate that hedging of natural gas prices reduces price volatility.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or financial instrument?

A. Gulf Power hedged 35,180,000 MMBtu of natural gas in 2016 using financial instruments. This represents 56% of Gulf's 62,878,723 MMBtu of actual gas burn for Smith Unit 3 plus the actual gas burn for the Central Alabama PPA combined cycle unit during the period. The total amount of natural gas burn by month for these units is reported on Schedule 4 of Exhibit CSB-3.

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 fixed the price of 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 2016 through December 2016?
A. No fees, commissions, or premiums were paid by Gulf on the financial hedge transactions during this period. Gulf's 2016 hedging program activities for the period January through December 2016 resulted in a net financial loss of $54,060,780 as shown on line 2 of Schedule A-1, period-to-date, for the month of December 2016 included in my Exhibit CSB-2.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?
A. No.

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

period January 2016 through December 2016. In addition, Schedule A-12 of my Exhibit CSB-3 contains purchased power capacity cost information for the period January 2016 through December 2016.

Q. What is the actual purchased power capacity cost true-up amount related to the period of January 2016 through December 2016 to be addressed in the period January 2018 through December 2018?

A. An amount of $545,959 to be refunded to customers through 2018 purchased power capacity clause rates as shown on Schedule CCA-1 of Exhibit CSB-1.

Q. How was this amount calculated?

A. The $545,959 was calculated by taking the difference between the estimated January 2016 through December 2016 over-recovery of $149,231 and the actual over-recovery of $695,190, which is the sum of lines 10, 11, and 14 under the total column of Schedule CCA-2 of Exhibit CSB-1. The estimated true-up amount for this period was approved in FPSC Order No. PSC-16-0547-FOF-EI dated December 5, 2016. Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed August 4, 2016.

Q. Please describe Schedules CCA-2 and CCA-3 of your exhibit.

A. Schedule CCA-2 shows the monthly calculation of the actual over/under-recovery of purchased power capacity costs for the period January 2016 through December 2016. Schedule CCA-3 of my Exhibit CSB-1 is the monthly calculation of the interest provision on the average recovery balance for the period January 2016 through December 2016.

Q. Please describe Schedule CCA-4 of Exhibit CSB-1.

A. Schedule CCA-4 provides additional details related to purchased power capacity costs which also appear on Lines 1 and 2 of Schedule CCA-2.

Q. During the period January 2016 through December 2016, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. The actual total capacity payments for the January 2016 through December 2016 recovery period, as shown on line 4 of Schedule CCA-2 Exhibit CSB-1, was $87,295,986. Gulf's total re-projected net purchased power capacity cost for the same period was $87,336,137, as indicated on line 4 of Schedule CCE-1B of my Exhibit CSB-2 filed August 4, 2016 in Docket No. 160001-EI. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $40,151 or 0.05% less than the re-projected amount. This lower actual cost is due to Gulf having higher external capacity receipts than the re-projected amount for the 2016 recovery period.

Q. Was Gulf's actual 2016 IIC capacity cost prudently incurred and properly allocated to Gulf?

A. Yes. Gulf's capacity costs were incurred in accordance with the reserve sharing provisions of the IIC in which Gulf has been a participant for many years. Gulf's participation in the integrated Southern electric system that is governed by the IIC has produced and continues to produce substantial benefits for Gulf's customers and has been recognized as being prudent by the Florida Public Service Commission in previous proceedings and reviews. Per contractual agreement in the IIC, Gulf and the other SES operating companies are obligated to provide for the continued operation of their electric facilities in the most economical manner that achieves the highest possible service reliability. The coordinated planning of future SES generation resource additions that produce adequate reserve margins for the benefit of all SES operating companies' customers facilitates this "continued operation" in the most economical manner. The IIC provides for mechanisms to facilitate the equitable sharing of the costs associated with the operation of facilities that exist for the mutual benefit of all the operating companies.

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. 20170001-EI
July 27, 2017

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 Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

Q. Have you previously filed testimony before this Commission in Docket 20170001-EI?

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

Q. Has your job description, education, background or professional experience changed since that time?

A. No.

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 through December 2017 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 2017 through

December 2017 and to summarize any noteworthy variances in these areas. The current estimated/actual costs consist of actual expenses for the period January 2017 through June 2017 and projected costs for July 2017 through December 2017. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transactions expenses and purchased power capacity costs.

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 sixteen 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-4) and ____ (CSB-5).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period January 2017 through December 2017, the Purchased Power Capacity Cost estimated true-up calculations for the period January 2017 through December 2017 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.

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 2018 through December 2018?

A. The fuel cost recovery true-up factor for this period is an increase of 0.2994 cents per kWh. As shown on Schedule E-1A, this includes an estimated under-recovery for the January through December 2017 period of $21,854,879. It also includes a final under-recovery for the January through December 2016 period of $10,797,411 (see Schedule 1 of Exhibit CSB-1 filed in this docket on March 1, 2017). The resulting total under-recovery of $32,652,290 will be addressed in Gulf's proposed 2018 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-4.

Total Fuel and Net Power Transactions

Gulf's currently projected recoverable total fuel and net power transactions (line 14) cost for the period is $394,751,289 which is $12,053,873 or 3.15% above the original projected amount of $382,697,416. The higher total fuel and net power transactions expense for the period is attributed to higher fuel cost of generated power, offset by lower purchased power expense and higher than expected revenue from power sales. The resulting average per unit fuel and net power transactions cost is projected to be 3.3931 cents per kWh or 6.26% higher than the original projection of 3.1931 cents per kWh. The higher average per unit fuel and net power transactions cost is attributed to a higher per unit fuel cost of generated power and a lower per unit fuel cost of power sales for the period, offset by lower per unit fuel cost of purchased power.

Total Cost of Generated Power

Gulf's currently projected recoverable total fuel cost of generated power (line 4) for the twelve months ending December 2017 is $318,539,632 which is $43,962,216 or 16.01% above the original projected amount of $274,577,416. Total generation is expected to be 9,847,362 MWh compared to the original projected generation of 9,352,830 MWh or 5.29% above original projections. The resulting average fuel cost is expected to be 3.2348 cents per kWh or 10.18% above the original projected amount of 2.9358 cents per kWh. The higher total fuel expense is due to higher than originally projected quantity of generated power, combined with a higher average per unit fuel cost (cents per kWh).

The total fuel cost of system net generation (line 1) for the first six months of 2017 was $127,428,086 which is $2,261,328 or 1.81% higher than the projected cost of $125,166,758. On a fuel cost per kWh basis, the actual cost was 3.0652 cents per kWh, which is 2.41% higher than the projected cost of 2.9930 cents per kWh. This higher than projected cost of system generation on a cents per kWh basis was due to the average heat rate (Btu/kWh) of the generating units that operated being 1.86% higher than projected. The reduced efficiency of units operating during the period is offset by lower than projected per unit cost of coal ($ per ton) and effective cost of natural gas ($/Mcf). This information is found on Schedule A-3 Period to Date of the June 2017 Monthly Fuel Filing.

Q. How did the total projected cost of coal burned compare to the actual cost for the first six months of 2017?

A. The total cost of coal burned (including boiler lighter) for the first six months of 2017 was $69,065,163 which is $1,047,410 or 1.49% lower than the projection of $70,112,573. The total coal-fired generation was 2,078,436 MWh which is 4.03% lower than the projection of 2,165,676 MWh for the period. On a fuel cost per kWh basis, the actual cost was 3.32 cents per kWh which is 2.47% higher than the projected cost of 3.24 cents per kWh. The higher per kWh cost of coal-fired generation is due to the weighted average heat rate (Btu/kWh) of the coal-fired generating units that operated being 19.26% higher than projected offset by actual coal prices (including boiler lighter) being 5.08% lower than projected on a $/MMBtu basis. This information is found on Schedule A-3 Period to Date of the June 2017

Monthly Fuel Filing. Gulf has fixed price coal contracts in place for the period to limit price volatility and ensure reliability of supply. Actual average prices for coal purchased during the period are lower due to a change in the timing and mix of contract shipments to Gulf's coal-fired generating plants.

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first six months of 2017?

A. The total cost of natural gas burned for generation for the first six months of 2017 was $57,885,281 which is $3,215,139 or 5.88% higher than Gulf's projection of $54,670,142. The total gas-fired generation was 2,066,326 MWh which is 3.11% higher than the projection of 2,004,049 MWh for the period. The total cost of natural gas burned for generation is higher than forecast due to a higher quantity of natural gas consumed for generation. Gulf's gas-fired generating units consumed 14,676,570 MMBtu or 7.26% higher than the projected amount of 13,683,608 MMBtu during the period. On a cost per unit basis, the actual cost of gas-fired generation was 2.80 cents per kWh which is 2.56% higher than the projected cost of 2.73 cents per kWh. The gas-fired unit heat rate (Btu/kWh) was 3.96% less efficient than projected. This information is found on Schedule A-3 Period to Date of the June 2017 Monthly Fuel Filing.

<u>Total Fuel Cost and Gains on Power Sales</u>

Gulf's currently projected recoverable fuel cost and gains on power sales (line 12) for the twelve months ending December 2017 are $123,599,940 or 16.84% above the original projected amount of $105,784,000. Total power sales are expected to be 5,376,566 MWh compared to the original projection of 4,155,001 MWh or 29.40% above projections.

The higher total credit to fuel expense from power sales is attributed to a higher quantity of power sales offset by a lower reimbursement rate for power sales than originally projected. The currently projected price for the fuel cost and gains on power sales is 2.2989 cents per kWh which is 9.70% lower than the original projection of 2.5459 cents per kWh. The lower projected fuel reimbursement rate for power sales during the period is due to lower projected fuel costs associated with the units that set system pool interchange rates for power sales.

The total fuel cost of power sold for the first six months of 2017 was $47,322,439 which is $1,577,561 or 3.23% lower than the projection of $48,900,000. The quantity of power sales for the period was 40.77% higher than projected. The actual cost was 1.7864 cents per kWh which is 31.25% below the projected cost of 2.5984 cents per kWh. This information is found on Schedule A-1, Period to Date, line 17 of the June 2017 Monthly Fuel Filing.

Total Cost of Purchased Power

Gulf’s currently projected recoverable fuel cost of purchased power (line 7) for the twelve months ending December 2017 is $199,811,597 or 6.59% below the original projected amount of $213,904,000. The total amount of purchased power is expected to be 7,163,310 MWh compared to the original projection of 6,787,282 MWh or 5.54% above projections. The resulting average fuel cost of purchased power is expected to be 2.7894 cents per kWh or 11.49% below the original projected amount of 3.1515 cents per kWh. The lower total fuel cost of purchased power is attributed to a lower projected price per kWh for purchased power for the period.

The total fuel cost of purchased power for the first six months of 2017 was $92,916,497 which is $13,389,503 or 12.60% lower than our projection of $106,306,000. The lower than projected purchased power expense is due to the actual price of purchases being lower than projected offset somewhat by a greater quantity of purchases made. Purchased power quantity is 16.26% higher due to the availability of lower cost energy purchases. On a fuel cost per kWh basis, the actual cost was 2.3741 cents per kWh which is 24.82% lower than the projected cost of 3.1577 cents per kWh. This information is found on Schedule A-1, Period to Date, line 12 of the June 2017 Monthly Fuel Filing. The 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 discuss the status of Gulf's Hedging program.

A. 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, Gulf agreed to a moratorium on any new financial hedges through the end of calendar year 2017. 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, Gulf agreed to continue its existing moratorium for new natural gas financial hedges until January 1, 2021. Accordingly, Gulf has not entered any new financial natural gas hedges since the effective date of the stipulated moratorium.

Q. For the period January 2017 through June 2017, 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 14,120,000 MMBtu of natural gas for the period. This equates to 48% of the actual natural gas burn for Gulf's combined cycle generating units during the period of 29,333,357 MMBtu. This amount is the sum of the Plant Smith Unit 3 burn as reported on Schedule A-3 Period to Date of the June 2017 Monthly Fuel Filing and the Central Alabama PPA natural gas burn for the period.

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 either a NYMEX Last Day price or Gas Daily 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 a hedging settlement loss of $10,893,202 for the period January through June 2017. This information is found on Schedule A-1, Period to Date, line 2 of the June 2017 Monthly Fuel Filing.

III. FUEL PROCUREMENT

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?
A. No.

Q. Should Gulf's fuel and net power transactions cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf has followed its Risk Management Plan for Fuel Procurement in securing the fuel supply for its electric generating plants. Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that natural gas is available during times when gas supply is curtailed or unavailable. Gulf's fuel oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf makes sales of power when available and gets reimbursed at the marginal cost of replacement fuel. This fuel reimbursement is credited back to the fuel cost recovery clause so that lower cost fuel purchases made on behalf of Gulf's customers remain to the benefit of those customers. Gulf purchases power when necessary to meet customer load requirements and when the cost of purchased power is expected to be less than the cost of system generation. The fuel cost of purchased power is the lowest cost available in the market at the time of purchase to meet Gulf's load requirements.

IV. 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-4 relate to the calculation of these factors?

A. Schedules CCE-1A, CCE-1B , CCE-2, CCE-3 and CCE-4 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2018 through December 2018 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2018 through December 2018?

A. The true-up for this period is an increase of 0.0289 cents per kWh as shown on Schedule CCE-1A. This includes an estimated under-recovery of $3,698,545 for January 2017 through December 2017. It also includes a final over-recovery of $545,959 for the period of January 2016 through December 2016 (see Schedule CCA-1 of Exhibit CSB-1 filed in this docket on March 1, 2017). The resulting total under-recovery of $3,152,586 will be addressed in Gulf’s proposed 2018 purchased power capacity cost recovery factors.

Q. During the period January 2017 through December 2017, 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-4, Gulf’s total capacity payments projection for the January 2017 through December 2017 recovery period is $86,474,608. Gulf's original projection for the period was $86,064,527 and is shown on lines 1 and 2 of Schedule CCE-1 filed September 1, 2016. The difference between these projections is $410,081 or 0.48% higher than the original projection of capacity payments.

Q. How did the total projected capacity costs compare to the actual cost for the first six months of 2017?

A. Actual capacity costs during the first six months of 2017 were $43,288,449 (Lines 1 & 2 of Schedule CCE-1B) which is $247,958 higher than projected amount of $43,040,491 for the period (from Lines 1 & 2 of Schedule CCE-1 filed September 1, 2016).

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-5 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 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. Gulf estimated, and included in revised PPCC rates effective July 1, 2017, an annualized credit of $7.7 million. Gulf now estimates the credit to be

$3,876,774 for the six months July through December 2017 ($7,753,548 annualized). The Scherer/Flint Credit for the period July through December 2017, as shown on line 4 of Schedule CCE-1B of Exhibit CSB-4, has the effect of lowering retail capacity payments (line 5). The calculation of the credit, as presented in Exhibit CSB-5, 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 and Exhibits of
C. Shane Boyett
Docket No. 20170001-EI
Date of Filing: August 24, 2017

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 and Cost Recovery Manager for Gulf Power Company.

Q. Have you previously filed testimony before this Commission in Docket 20170001-EI?

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

Q. Has your education, background or professional experience changed since that time?

A. No.

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 1, 2018 through December 31, 2018, along with the resulting calculation of Gulf Power's fuel cost recovery and purchased power capacity factors for the period January 2018 through December 2018.

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

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

Exhibit Number	Summary
CSB-6	15 schedules related to Fuel and Purchased Power Capacity Calculations
CSB-7	2018 Scherer/Flint Credit Calculation
CSB-8	A schedule filed as an attachment to my pre-filed testimony that compares actual and projected fuel cost of net generation for the past ten years. The purpose of this exhibit is to demonstrate the accuracy of Gulf's short-term fuel expense projections.
CSB-9	Gulf Power Company's Hedging Information Report filed with the Commission Clerk on April 3, 2017, and assigned Document Number DN 03980-2017 (redacted) and 03982-2017 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for August 2016 through December 2016 in compliance with Order No. PSC-08-0316-PAA-EI.

CSB-10 Gulf Power Company's Hedging Information Report filed with the Commission Clerk on August 18, 2017, and assigned Document Number DN 07141-2017 (redacted) and DN 07144-2017 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for January 2017 through July 2017 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-6), _____(CSB-7), _____(CSB-8), _____(CSB-9), and _____(CSB-10)

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. Mr. Boyett, are there any changes to your 2017 estimated/actual testimony or exhibits that were filed in this docket on July 27, 2017?

A. Yes. An inadvertent calculation error was found on Schedule E-1B which also impacted Schedule E-1A of my Exhibit CSB-4. The two affected schedules are included in my Exhibit CSB-6 and have been marked as “Revised 8/24/27.” The revision corrects the application of interest for an accounting adjustment and results in a $1,525 reduction to the estimated true-up under-recovery amount for 2017. The revised estimated true-up amount of $21,853,354 is presented on Schedule E-1A of my Exhibit CSB-6.

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 2018 through December 2018.

A. As shown on Revised Schedule E-1A of Exhibit CSB-6, the total true-up amount of $32,650,765 includes an estimated under-recovery for the January 2017 through December 2017 period of $21,853,354, in addition to a final under-recovery for the period January through December 2016 of $10,797,411. The estimated under-recovery for the January 2017 through December 2017 period includes six months of actual data and six months of estimated data as reflected on Revised Schedule E-1B.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2016 through December 2016?

A. The GPIF result shown on Line 27 of Schedule E-1 is a decrease of 0.0187¢/kWh to the levelized fuel factor, thereby penalizing Gulf $2,043,225.

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 25 of Schedule E-1.

Q. What is the levelized projected fuel factor for the period January 2018 through December 2018 and how does it compare with the levelized fuel factor for the current period?

A. Gulf has proposed a levelized fuel factor of 3.789¢/kWh. This factor is based on projected fuel and purchased power energy expenses for January 2018 through December 2018 and projected kWh sales for the same period, and includes the true-up and GPIF amounts. The projected levelized fuel factor for 2018 is 0.650¢/kWh more or 20.71 percent higher than the levelized fuel factor in place January 2017 through December 2017.

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

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

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

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 3.810¢/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 2018 through December 2018. These factors included the GPIF and true-up and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2017, 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 2017 is 3.163¢/kWh compared with the proposed factor of 3.810¢/kWh. For a residential customer who is billed for 1,000 kWh in

January 2017, the fuel portion of the bill would increase from $31.63 to $38.10.

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 2018 through December 2019. 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 $1.93 per month based on the 2018 projected solar-weighted average annual avoided energy cost of 3.1 cents per kWh.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2018 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

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

2015 actual gains	596,791
2016 actual gains	700,065
2017 estimated gains	1,730,961
Three-Year Average	$ 1,009,272

This amount represents the minimum projected threshold for 2018 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2018.

Total Fuel and Net Power Transactions

Q. What is Gulf's projected recoverable total fuel and net power transactions cost for the January 2018 through December 2018 recovery period?

A. Gulf's projected total fuel and net power transactions cost for the period is $393,450,117 as shown on Schedule E-1 line 16 of Exhibit CSB-6.

Q. How does the total projected fuel and net power transactions cost for the 2018 period compare to the updated projection of fuel cost for the same period in 2017?

A. The total updated cost of fuel and net power transactions for 2017, reflected on Schedule E-1B-1 line 14 of Exhibit CSB-4 filed in this docket on July 27, 2017, is projected to be $394,751,289. The projected total cost of fuel and net power transactions for the 2018 period reflects a decrease of $1,301,172 or 0.33% less than the same period in 2017. On a fuel cost per kWh basis, the 2017 projected cost is 3.3931 cents per kWh, and the 2018 projected fuel cost is 3.3240 cents per kWh, a decrease of 0.0691 cents per kWh or 2.04%.

<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 2018 as shown in exhibit CSB-6, Schedule E-1, line 5 is $275,601,297.

Q. How does the projected total fuel cost of generated power for the 2018 period compare to the updated projection of fuel cost for the same period in 2017?

A. The total updated cost of fuel to meet 2017 system generated power needs, reflected on Schedule E-1B-1, line 4 of CSB-4 filed in this docket on July 27, 2017, is projected to be $318,539,632. The projected total cost of fuel to meet system net generation needs for the 2018 period reflects a decrease of $42,938,335 or 13.48% less than the same period in 2017. Total system net generation in 2018 is projected to be 8,752,133 MWh, which is 1,095,229 MWh or 11.12% less than is currently projected for 2017. The lower projected total fuel expense is the result of a lower projected quantity of total MWh produced combined with lower estimated hedging settlement costs for the period. On a fuel cost per kWh basis, the 2017 projected cost is 3.2348 cents per kWh, and the 2018 projected fuel cost is 3.1490 cents per kWh, a decrease of 0.0858 cents per kWh or 2.65%. The lower average per unit fuel cost in cents per kWh is the result of slightly higher coal generation costs offset by lower gas-fired generation cost for the 2017 period.

Weighted average coal burned price including boiler lighter fuel for 2017 as reflected on Schedule E-3, line 32 of my testimony filed in this docket on July 27, 2017, is projected to be $2.79 per MMBtu. Weighted average coal burned price including boiler lighter fuel for 2018, as reflected on Schedule E-3, line 32 is projected to be $2.83 per MMBtu. These figures reflect a cost increase of $0.04 per MMBtu or 1.43%. The cost increase is due to coal supply contracts that will expire by the end of 2017 being replaced with market price coal supply agreements that are projected to be slightly higher in 2018.

Weighted average natural gas price for 2017, as reflected on Schedule E-3, line 33 of the exhibit to my testimony filed in this docket on July 27, 2017, is projected to be $4.14 per MMBtu. Weighted average natural gas price for 2018, as reflected on Schedule E-3, line 33 is projected to be $4.05 per MMBtu. This is a decrease in price of $0.09 per MMBtu or 2.17%.

As reflected on Schedule E-3, lines 40 and 41, the projected fuel cost of Gulf's coal-fired generation is 3.15 cents per kWh, and the projected fuel cost of Gulf's gas-fired generation is 2.83 cents per kWh for the 2018 period.

<u>Fuel Cost and Gains on Power Sales</u>

Q. What are Gulf's projected recoverable fuel cost and gains on power sales for the 2018 period?

A. Gulf's projected recoverable fuel cost and gains on power sales is $92,403,521 as shown on Schedule E-1, line 14.

Q. How does the total projected recoverable fuel cost and gains on power sales for the 2018 period compare to the projected recoverable fuel cost and gains on power sales for the same period in 2017?

A. The total updated recoverable fuel cost and gains on power sales in 2017, reflected on Schedule E-1B-1, line 12 of my exhibit filed in this docket on July 27, 2017, is projected to be $123,599,940. The projected recoverable fuel cost and gains on power sales in 2018 represents a decrease of $31,196,419 or 25.24%. Total quantity of power sales in 2018 is projected to be 3,621,814 MWh, which is 1,754,752 MWh or 32.64% lower than currently projected for 2017. On a fuel cost per kWh basis, the 2017 projected cost is 2.2989 cents per kWh, and the 2018 projected fuel cost is 2.5513 cents per kWh, which is an increase of 0.2524 cents per kWh or 10.98%. The lower total credit to fuel expense from power sales is attributed to a lower projected quantity of power sales from units operating to meet incremental system loads.

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

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

A. Gulf's projected recoverable cost for energy purchases is $210,252,341 as shown on Schedule E-1, line 9.

Q. How does the total projected purchased power cost for the 2018 period compare to the projected purchased power cost for the same period in 2017?

A. The total updated cost of purchased power to meet 2017 system needs, reflected on Schedule E-1B-1, line 7 of my testimony filed in this docket on July 27, 2017, is projected to be $199,811,597. The projected cost of purchased power to meet system needs in 2018 is $10,440,744 or 5.23% higher than is currently projected for 2017. The total quantity of purchased power in 2018 is projected to be 6,706,285 MWh, which is 457,025 MWh or 6.38% lower than is currently projected for 2017. On a fuel cost per kWh basis, the 2017 projected cost is 2.7894 cents per kWh, and the 2018 projected fuel cost is 3.1352 cents per kWh, which represents an increase of 0.3458 cents per kWh or 12.40%.

II. FUEL PROCUREMENT

Q. Does the 2018 projection of fuel cost of net generation reflect any major changes in Gulf's fuel procurement program for this period?

A. No. As in the past, Gulf's coal requirements are purchased in the market through the Request for Proposal (RFP) process that has been used for many years by Southern Company Services - Fuel Services as agent for Gulf. Coal will be delivered under both existing and new negotiated coal transportation contracts. 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 27, 2017 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 2017 and is included in my Exhibit CSB-10 as previously filed with this Commission on August 18, 2017.

Q. What are the results of Gulf's natural gas price hedging program for the period August 2016 through July 2017?

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 2016 and July 2017, Gulf recorded hedging settlement costs of $29,478,936. Pursuant to Order No. PSC-08-0316-PAA-EI, Gulf filed Hedging Information Reports with the Commission on April 3, 2017, and August 18, 2017, detailing its natural gas hedging transactions for August 2016 through July 2017. I am sponsoring these reports as Exhibits CSB-9 and CSB-10 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-6 and Exhibit CSB-7 relate to the calculation of the PPCC recovery factors for the period January 2018 through December 2018.

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. Line 4 reflects the inclusion of the Scherer/Flint Credit, which is calculated and presented in my Exhibit CSB-7. 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 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 the consolidated Docket Nos. 20160186-EI and 20160170-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 demand allocation factors used in the PPCC Recovery Clause have been calculated using the 2015 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 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 $8.35.

Q. What is Gulf’s projected recoverable capacity payments for the 2018 cost recovery period?

A. The total recoverable capacity payments for the period are $78,947,920. This amount is captured in the Schedule CCE-1, line 11. Schedule CCE-4 shows the projected cost associated with Southern Intercompany Interchange and lists the long-term purchased power contracts that are included for capacity cost recovery, their associated capacity amounts in megawatts, and the resulting cost. Also included in Gulf's 2018 projection of capacity cost is revenue produced by a market-based agreement between the Southern electric system operating companies and South Carolina PSA. The total capacity cost of $86,277,012 is shown on Schedule CCE-4, line 14. The total capacity cost 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 in the amount of $84,000 in its capacity cost recovery projection. This amount is captured on Schedule CCE-1, line 3 of my Exhibit CSB-6. Also, pursuant to the Stipulation and Settlement Agreement approved by Order No. PSC 17-0178-S-EI in the consolidated Docket Nos. 20160186-EI and 20160170-EI, Gulf has estimated a Scherer/Flint Credit in the amount of $8,258,898 for the period 2018. The Scherer/Flint Credit calculation is presented in my Exhibit CSB-7 and also appears on Schedule CCE-1, line 4 of my Exhibit CSB-6 as an offset to capacity payments.

Q. How do the total projected net jurisdictional capacity payments for the 2018 period compare to the current estimated net jurisdictional capacity payments for the same period in 2017?

A. Gulf's 2018 Projected Jurisdictional Capacity Payments, found on Schedule CCE-1, line 7, are $75,738,532. This amount is $4,408,035 or 5.50% less than the current estimate of $80,146,567 (Schedule CCE-1B, line 6) for 2017 that was filed in my actual/estimated true-up testimony in this docket on July 27, 2017. The projected capacity payment decrease in 2018 is the result of incorporating a full year of the Scherer/Flint credit compared to only six months of the Scherer/Flint credit for the twelve-month period ending December 2017.

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 Cycle 1 billings in January 2018 and continuing through the last billing cycle of December 2018.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. L. Nicholson
Docket No. 170001-EI
Date of Filing: March 15, 2017

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

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

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from Auburn University in 1998. I joined Southern Company with Alabama Power in 1996 as a summer intern. Upon graduation in 1998, I joined Southern Company Services (SCS), a subsidiary of Southern Company. During my time at SCS, I worked in Farley Project and in Generating Plant Performance (GPP), where I progressed through various engineering positions with increasing responsibilities. My primary responsibility in Farley Project was to coordinate design changes to Plant Farley. My primary responsibility in GPP was to conduct heat rate tests and performance tests on plant equipment. I joined Southern Nuclear Operating Company (SNC) in 2011. At SNC, my primary responsibility was to coordinate responses to requests from the U. S. Nuclear Regulatory Commission for various projects. I joined SCS in 2014 as a Performance and Reliability Engineer, where my primary responsibility was to report key performance indicators on a monthly basis. I joined Gulf Power in 2015 in my current job position as Power Generation Specialist, Senior as previously mentioned in my testimony. In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

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

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2016, through December 31, 2016.

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

A. Yes. I have prepared 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 4 through 8 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by FPSC Order No. PSC-15-0586-FOF-EI is on page 9 of Schedule 2. The results are: Crist 6, +6.15 points; Crist 7, -7.78 points; Daniel 1, +10.00 points; Daniel 2, +7.00 points; and Smith 3, +7.78 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 2015, 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:

Crist 6, -3.67 points; Crist 7, -2.69 points; Daniel 1, -10.00 points; Daniel 2, -10.00 points, and Smith 3, -10.00 points.

Q. What number of Company points was achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?
A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was -6.75 as indicated on page 2 of Schedule 4. This calculated to a penalty in the amount of $2,043,225.

Q. Please summarize your testimony.
A. In view of the adjusted actual equivalent availabilities, as shown on page 9 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 14 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a penalty in the amount of $2,043,225 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. 20170001-EI
Date of Filing: August 24, 2017

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

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

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from Auburn University in 1998. I joined Southern Company with Alabama Power in 1996 as a summer intern. Upon graduation in 1998, I joined Southern Company Services (SCS), a subsidiary of Southern Company. During my time at SCS, I worked in 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 Power Generation Specialist, Senior as previously mentioned in my testimony. In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 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 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 2018.

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, 2018 through December 31, 2018?

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, 2018 through December 31, 2018.
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 also on pages 17 through 26 of Schedule 3 of my exhibit, for use in adjusting the annual actual unit heat rates to target conditions.

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

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 170001-EI
FILED: 3/1/2017

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, where I have assumed positions of increasing responsibility during my 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 duties 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 2016 through December 2016 for the Fuel and Purchased Power Cost Recovery Clause (“Fuel Clause”), the Capacity Cost Recovery Clause (“Capacity Clause”), and the wholesale incentive benchmark for January 2017 through December 2017.

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 2016 through December 2016?

A. The final true-up amount for the Capacity Clause for the period January 2016 through December 2016 is an under–recovery of $4,411,715.

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 2016 Through December 2016", provides the calculation for the final under–recovery of $4,411,715. The actual capacity cost under-recovery, including interest, was $7,397,775 for the period January 2016 through December 2016 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $2,986,060 actual/estimated under-recovery approved in Order No. PSC-16-0547-FOF-EI issued December 5, 2016 in Docket No. 160001-EI, results in a final under-recovery of $4,411,715 for the period, as identified in Document No. 1, page 4 of 4. This amount will be applied in the calculation of the capacity cost recovery factors for the period January 2018 through December 2018.

Q. What is the estimated effect of this $4,411,715 under-recovery for the January 2016 through December 2016 period on residential bills during January 2018 through December 2018?

A. The $4,411,715 under-recovery will increase a 1,000 kWh residential bill by approximately $0.28.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2016 through December 2016?

A. The final Fuel Clause true-up for the period January 2016 through December 2016 is an under-recovery of $21,571,557. The actual fuel cost over-recovery, including interest, was $101,068,239 for the period January 2016 through December 2016. This $101,068,239 amount, less the $122,639,796 actual/estimated over-recovery amount approved in Order No. PSC-16-0547-FOF-EI, issued December 5, 2016 in Docket No. 160001-EI, results in a net under-recovery amount for the period of $21,571,557.

Q. What is the estimated effect of the $21,571,557 under-recovery for the January 2016 through December 2016 period on residential bills during January 2018 through December 2018?

A. The $21,571,557 under-recovery will increase a 1,000 kWh residential bill by approximately $1.13.

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 2016 Through December 2016". It shows the calculation of the final fuel under-recovery of $21,571,557.

Line 1 shows the total company fuel costs of $648,541,229 for the period January 2016 through December 2016. The jurisdictional amount of total fuel costs is

$648,355,747, 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 over-recovered fuel costs for the period, shown on line 4. The resulting $82,662,587 over-recovered fuel costs for the period, interest, true-up collected and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual over-recovery amount of $101,068,239 shown on line 9. The $101,068,239 actual amount less the $122,639,796 actual/estimated over-recovery amount shown on line 10, results in a final under-recovery amount of $21,571,557 for the period January 2016 through December 2016, as shown on line 11.

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 2016 Through December 2016." It shows the calculation of the actual over-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 2016 through December 2016?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost is $67,063,834 less than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2016 through December 2016?

A. As shown on line C3 of Document No. 3, the company collected $16,081,168, or 2.2 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 2016 through December 2016. 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 2016 through December 2016 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-12-0498-PAA-EI, issued in Docket No. 120153-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-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2017, as derived in accordance with Order No. PSC-01-2371-FOF-EI, in Docket No. 010283-EI?

A. The company's 2017 benchmark is $1,493,095, which is the three-year average of $3,298,966, 496,810, and $683,509 actual gains on non-separated wholesale sales, excluding emergency sales, for 2014, 2015, and 2016, respectively.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170001-EI
FILED: 07/27/2017

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 Manager, Rates in the Regulatory Affairs Department.

Q. Have you previously filed testimony in Docket No. 20170001-EI?

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

Q. Has your job description, education, or professional experience changed since then?

A. No, it has not.

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 2017 through December 2017 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the January 2018 through December 2018 projection period. My testimony addresses the recovery of the fuel and purchased power costs as well as capacity costs for the year 2017, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2018 fuel and purchased power costs and capacity cost recovery factors.

Q. Have you prepared any exhibits 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 2017 through December 2017. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period January 2017 through December 2017. Document No. 3 provides the actual/estimated capital costs during the period of January 2017 through December

2017 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 the projects. These documents are furnished as support for the projected 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 2018 through December 2018 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period of January 2018 through December 2018 is an over-recovery of $17,081,137.

Q. How did Tampa Electric calculate the estimated net true-up to be applied in the January 2018 through December 2018 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2018 is the sum of the final true-up amount for the period January 2016 through December 2016 and the actual/estimated true-up amount for the period January 2017 through December 2017.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2016?

A. The final true-up is an under-recovery of $21,571,557. The actual fuel cost over-recovery, including interest is $101,068,239 for the period January 2016 through December 2016. The $101,068,239 amount, less the actual/estimated over-recovery amount of $122,639,796 approved in Order No. PSC-16-0547-FOF-EI, issued December 5, 2016 in Docket No. 160001-EI results in a net-under recovery amount for the period of $21,571,557.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery amount for the period January 2017 through December 2017?

A. The actual/estimated fuel and purchased power cost recovery true-up is an over-recovery amount of $38,652,694 for the January 2017 through December 2017 period. 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.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2018 through December 2018 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2018 through December 2018 is an under-recovery of $2,762,938 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 2018 through December 2018 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2018 capacity cost recovery factors is the sum of the final true-up amount for 2016 and the actual/estimated true-up amount for January 2017 and December 2017.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2016?

A. The final 2016 true-up is an under-recovery of $4,411,715. The actual capacity cost under-recovery, including interest, was $7,397,775 for the period January 2016 through December 2016. This amount, less the $2,986,060 actual/estimated under-recovery amount approved in Order

No. PSC-16-0547-FOF-EI, issued December 5, 2016 in Docket No. 160001-EI results in a net under-recovery amount for the period of $4,411,715 as identified in Exhibit No. PAR-2, Document No. 2, page 1 of 5.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2017 through December 2017?

A. The actual/estimated true-up amount is an over-recovery of $1,648,777 as shown on Exhibit No. PAR-2, Document No. 2, page 1 of 5.

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 Polk Unit 1 and the Big Bend Units 1-4 ignition conversion projects for the period January 2017 through December 2017. 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 Polk Unit 1 ignition conversion project capital costs, including depreciation and return, for the period January 2017 through December 2017 are less than the project’s fuel savings. This is shown on Exhibit No. PAR-2, Document No. 3, 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-12-0498-PAA-EI, issued in Docket 120153-EI on September 27, 2012.

The Big Bend Units 1-4 ignition conversion project capital costs, including depreciation and return, for the period January 2017 through December 2017 are less than the project’s fuel savings, as shown on Exhibit No. PAR-2, Document No. 3, 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-14-0309-PAA-EI, issued in Docket 140032-EI on June 12, 2014.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170001-EI
FILED: 08/24/2017

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 Manager, Rates in the Regulatory Affairs Department.

Q. Have you previously filed testimony in Docket No. 20170001-EI?

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

Q. Has your job description, education, or professional experience changed since then?

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, including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the wholesale incentive benchmark for January 2018 through December 2018. 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 2018.

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 2018 through December 2018 as well as Schedule H1 for January through December, 2015 through 2018. 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 $10,902,732 after jurisdictional separation, prior year true-up, and application of the revenue tax factor, for estimated expenses in 2018.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2018 through December 2018.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per Kw**
RS Secondary	0.066	
GS and CS Secondary	0.060	
GSD, SBF Standard		
Secondary		0.20
Primary		0.20
Transmission		0.20
IS, IST, SBI		
Primary		0.14
Transmission		0.14
GSD Optional		
Secondary	0.047	
Primary	0.047	
LS1 Secondary	0.016	

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 0.056 cents per kWh compare to the factor for January 2017 through December 2017?

A. The proposed capacity cost recovery factor is 0.018 cents per kWh (or $0.18 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.074 cents per kWh for the January 2017 through December 2017 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 2018?

A. The appropriate amount for the 2018 period is 3.132 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 2018 through December 2018.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $47,392, 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 for the January 2017 through December 2017 period. The net true-up amount for this period is an over-recovery of $17,081,137.

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 2018 through December 2018. 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 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 traditional levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2018 through December 2018.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	3.132
Tier I (Up to 1,000 kWh)	2.818
Tier II (Over 1,000 kWh)	3.818
Distribution Primary	3.101
Transmission	3.069
Lighting Service	3.095
Distribution Secondary	3.330 (on-peak)
	3.047 (off-peak)

Distribution Primary	3.297 (on-peak)
	3.017 (off-peak)
Transmission	3.263 (on-peak)
	2.986 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor 3.132 cents per kWh compare to the levelized fuel adjustment factor for the January 2017 through December 2017 period?

A. The proposed fuel charge factor is 0.176 cents per kWh (or $1.76 per 1,000 kWh) higher than the average fuel charge factor of 2.956 cents per kWh for the January 2017 through December 2017 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2018 fuel and purchased power and capacity cost recovery projections?

A. No, there are not any significant events that are reflected in the 2018 projection.

Capital Projects Approved for Fuel Clause Recovery

Q. What did Tampa Electric calculate as the estimated Polk

Unit 1 ignition oil conversion project costs for the period January 2018 through December 2018?

A. The estimated Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2018 through December 2018 are $1,650,886. This is shown in Exhibit PAR-3, Document No. 4.

Q. Do Tampa Electric's estimated Polk Unit 1 ignition oil conversion project savings exceed estimated costs for the period January 2018 through December 2018?

A. Yes, as reflected in Exhibit No. PAR-3, Document No. 4, fuel savings exceed costs for the period January 2018 through December 2018.

Q. Should Tampa Electric's Polk Unit 1 ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2018 through December 2018 estimated fuel savings are greater than the project 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-2012-0498-PAA-EI, issued in Docket No. 20120153-EI on September 27, 2012.

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project costs for the period January 2018 through December 2018?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, are $4,877,765. 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 2018 through December 2018?

A. Yes, fuel savings exceed costs for the period January 2018 through December 2018. 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 2018 through December 2018 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 these two projects.

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.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2018?

A. The company's projected 2018 benchmark is $881,855, which is the three-year average of $496,810, $683,509 and $1,465,247 in gains on the company's non-separated wholesale sales, excluding emergency sales for 2015, 2016 and 2017 (actual/estimated), respectively.

Q. Does Tampa Electric expect gains in 2018 from non-separated wholesale sales to exceed its 2018 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected wholesale benchmark for 2018. Therefore, all sales margins are expected to flow back to the customers.

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 an increase of $1.32 beginning January 2018, when compared to the January 2017 through December 2017 charges. These charges are shown in Exhibit No. PAR-3, Document No. 2, on Schedule E10.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2018.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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 18 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 responsibilities. In January 2017, I was promoted to Manager, Unit Commitment, where I am responsible for commitment 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 2016 through December 2016. 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 2016 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2, respectively.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2016 through December 2016 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 32. Based upon 0.050 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $47,392 for the period.

Q. Please proceed with your review of the actual results for the January 2016 through December 2016 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $2,346,795,227. This produces the maximum penalty or reward amount of $9,571,866 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. 1

On this unit, 576.0 planned outage hours were originally scheduled for 2016. Actual outage activities required 518.9

planned outage hours. Consequently, the actual equivalent availability of 79.6 percent is adjusted to 79.0 percent as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 1,584.0 planned outage hours were originally scheduled for 2016. Actual outage activities required 1,974.9 planned outage hours. Consequently, the actual equivalent availability of 54.8 percent is adjusted to 58.0 percent as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 1,080.0 planned outage hours were originally scheduled for 2016. Actual outage activities required 1,102.4 planned outage hours. Consequently, the actual equivalent availability of 53.9 percent is adjusted to 54.0 percent as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 576.0 planned outage hours were originally scheduled for 2016. Actual outage activities required 585.2 planned outage hours. Consequently, the actual equivalent availability of 73.2 percent is adjusted to 73.2 percent as shown on Document No. 1, page 10 of 32.

Polk Unit No. 1

On this unit, 912.0 planned outage hours were originally scheduled for 2016. Actual outage activities required 1,170.0 planned outage hours. Consequently, the actual equivalent availability of 82.4 percent is adjusted to 85.2 percent, as shown on Document No. 1, page 11 of 32.

Bayside Unit No. 1

On this unit, 1,561.0 planned outage hours were originally scheduled for 2016. Actual outage activities required 1,757.4 planned outage hours. Consequently, the actual equivalent availability of 78.1 percent is adjusted to 80.2 percent, as shown on Document No. 1, page 12 of 32.

Bayside Unit No. 2

On this unit, 935.0 planned outage hours were originally scheduled for 2016. Actual outage activities required 625.6 planned outage hours. Consequently, the actual equivalent availability of 87.4 percent is adjusted to 84.2 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 entered into 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 entered into 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 2016 through December 2016 period?

A. This is shown on Document No. 1, page 2 of 32. Essentially, 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, 0.050, is then located in the GPIF table on page 2 of 32, and the reward amount of $47,392 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 $9,571,866, as shown in Document No. 1, pages 2 and 3.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. 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, Unit Commitment.

Q. Have you previously filed testimony in Docket No. 20170001-EI?

A. Yes, I submitted direct testimony on March 15, 2017.

Q. Has your job description, education, or professional experience changed since then?

A. No, it has not.

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 BSB-2, 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 2018 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Three of the company's coal-fired units, one integrated gasification combined cycle unit and three natural gas combined cycle units are included. These are Big Bend Units 2 through 4, Polk Units 1 and 2, and Bayside Units 1 and 2.

Q. Do the exhibits you prepared comply with the Commission-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 2018 through December 2018 represent the top 98 percent of the total forecasted system net generation for this period. Polk Unit 2 combined cycle entered commercial service in January 2017 and consists of 36 percent of the total forecasted system net generation for 2018. It is included in the GPIF calculation to meet the base load generation minimum. The company used one year of Polk Unit 2 combined cycle and three years of simple cycle historical operational data on which to base the unit targets.

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. A Big Bend Unit 4 forced outage was identified as an outlying outage; therefore, the associated forced outage hours were removed from the study.

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. Big Bend Units 2 through 4 and Polk Unit 1 heat rates were adjusted to reflect natural gas and coal co-firing operations.

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 2018 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 seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2018 period, the projected EUOF for Bayside Unit 1 is 2.7 percent, the POF is 14.8 percent. Therefore, the target EAF for Bayside Unit 1 equals 82.5 percent or:

100% - (2.7% + 14.8%) = 82.5%

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:

$$EAF_{MAX} = 1 - [0.80\ (2.7\%) + 0.95\ (14.8\%)] = 83.8\%$$

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,

$$EAF_{MIN} = 1 - [1.40\ (2.7) + 1.10\ (14.8)] = 80.0\%$$

The equivalent availability maximum and minimum for the other six 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 2018 are shown on page 21 of Document No. 1. Three GPIF units have a major outage of 28 days or greater in 2018; therefore, three Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for a planned outage from April 6, 2018 to April 17, 2018 and October 18, 2018 to November 28, 2018. There are 1,297 planned outage hours scheduled for the 2018 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 14.8 percent or:

$$\frac{1{,}297}{8{,}760} \times 100\% = 14.8\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 2 has a POF of 6.6 percent. Big Bend Unit 3 has a POF of 6.6 percent. Big

Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 17.3 percent. Polk Unit 2 has a POF of 5.8 percent. Bayside Unit 1 has a POF of 14.8 percent, and Bayside Unit 2 has a POF of 18.6 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 2.7 percent for Bayside Unit 1. The EUOF of Bayside Unit 1 is verified by the data shown on page 19, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

Or

$$\text{EUOF} = \frac{(99 + 135)}{8{,}760} \times 100\% = 2.7\%$$

Relative to Bayside Unit 1, the EUOF of 2.7 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 2

The projected EUOF for this unit is 31.9 percent. The unit will have two planned outages in 2018, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 61.5 percent.

Big Bend Unit 3

The projected EUOF for this unit is 26.7 percent. The unit will have two planned outages in 2018, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 66.7 percent.

Big Bend Unit 4

The projected EUOF for this unit is 14.7 percent. The unit will have two planned outages in 2018, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 78.7 percent.

Polk Unit 1

The projected EUOF for this unit is 8.3 percent. The unit will have two planned outages in 2018, and the POF is 17.3 percent. Therefore, the target equivalent availability for this unit is 74.4 percent.

Polk Unit 2

The projected EUOF for this unit is 11.0 percent. The unit will have one planned outage in 2018, and the POF is 5.8 percent. Therefore, the target equivalent availability for this unit is 83.2 percent.

Bayside Unit 1

The projected EUOF for this unit is 2.7 percent. The unit will have two planned outages in 2018, and the POF is 14.8 percent. Therefore, the target equivalent availability for this unit is 82.5 percent.

Bayside Unit 2

The projected EUOF for this unit is 4.0 percent. The unit will have two planned outages in 2018, and the POF is 18.6 percent. Therefore, the target equivalent availability for this unit is 77.3 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 76.3 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 19 of Document No. 1. Except for the months of April, October and November, 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 April, October and November, 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 or 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 31 through 37 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 2018 period.

A. The heat rate target for Big Bend Unit 2 is 11,320 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ± 478 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,619 Btu/Net kWh with a range of ± 367 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,448 Btu/Net kWh, with a range of ± 382 Btu/Net kWh. The heat rate target for Polk Unit 1 is 9,978 Btu/Net kWh with a range of ± 334 Btu/Net kWh. The heat rate target for Polk Unit 2 is 7,382 Btu/Net kWh with a range of ± 555 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,489 Btu/Net kWh with a range of ± 130 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,676 Btu/Net kWh with a range of ± 229 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 13 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric’s projection meet the criteria of the GPIF philosophy of the Commission?

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 the GPIF?

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 on pages 7 through 13. 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 $615,817,190 is shown on 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.

After all the individual savings are calculated, column

4 totals $29,174,790 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Bayside Unit 1, the weighting factor for average net operating heat rate is 4.66 percent as shown in the right-hand column on page 6. Pages 7 through 13 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, on Bayside Unit 1, page 12, if the unit operates at 7,360 average net operating heat rate, fuel savings would equal $1,359,627 and +10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 is a summary of the tables on pages 7 through 13. 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 $29,174,790. 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 2018 is \$2,508,779,992. This produces the maximum allowed jurisdictional incentive of \$10,237,065 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 \$10,237,065.

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).

$$
\begin{aligned}
GPIP = (&0.0211\ EAP_{BB2} + 0.0370\ EAP_{BB3} \\
&+ 0.0505\ EAP_{BB4} + 0.0073\ EAP_{PK1} \\
&+ 0.0483\ EAP_{PK2} + 0.0264\ EAP_{BAY1}
\end{aligned}
$$

$$+ 0.0516\ EAP_{BAY2} + 0.0267\ HRP_{BB2}$$
$$+ 0.0496\ HRP_{BB3} + 0.0736\ HRP_{BB4}$$
$$+ 0.0352\ HRP_{PK1} + 0.4539\ HRP_{PK2}$$
$$+ 0.0466\ HRP_{BAY1} + 0.0722\ HRP_{BAY2})$$

Where:

GPIP = Generating Performance Incentive Points

EAP = Equivalent Availability Points awarded/deducted for Big Bend Units 2, 3, and 4, Polk Units 1, 2 and Bayside Units 1 and 2

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 2, 3, and 4, Polk Units 1, 2 and Bayside Units 1 and 2

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2018 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.

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 Wholesale Marketing Group within the Wholesale Marketing, Planning & 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, Wholesale Origination in the Wholesale Marketing, Planning and Fuels Department. My responsibilities are to evaluate short and long-term purchase and sale opportunities within the wholesale power market and assist in wholesale origination and contract structures. 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 the 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 aggressively 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. Also, 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 2017 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 2.3 percent of the company's expected needs for 2017 will be met using purchased power. This includes economy energy purchases, purchases from qualifying facilities, pre-existing firm purchased power agreements with Pasco Cogen and Duke Energy Florida ("Duke"), and reliability purchases.

My testimony in previous years' dockets described the agreement with Pasco Cogen and Duke. However, in summary, the Pasco Cogen purchase is a call option with dual-fuel (*i.e.*, natural gas or oil) capability. The Pasco Cogen purchase began January 2009, is for 121 MW of combined-cycle capacity and continues through 2018. The Duke purchase was for 250 MW of combined-cycle capacity with a term of February 2016 through February 2017. In addition to providing customers with efficient combined-cycle energy, the company secured the Duke purchase to support its reserve margin during the construction of Tampa Electric's Polk Unit 2-5 combined cycle conversion ("Polk Unit 2 CC") project. Both the Pasco Cogen and Duke purchases were previously approved by the Commission as being cost-effective for Tampa Electric customers.

Q. Has Tampa Electric entered into any other wholesale power purchases in 2017?

A. Other than the purchases previously described in my testimony, the company has not entered into any additional power purchases in 2017.

Q. Does Tampa Electric anticipate entering into new wholesale power purchases for 2018 and beyond?

A. Tampa Electric does not anticipate entering into other purchased power agreements at this time. However, the company will continue to evaluate its options in light of changing circumstances and new opportunities. This evaluation includes the review of short and long-term capacity and energy purchases to augment its own generation for the year 2018 and beyond. The company always assesses the merits of long-term purchase opportunities and will consider securing additional long-term purchases that bring value to customers. Also, Tampa Electric will continue to evaluate and utilize the short-term purchased power market as part of its purchasing strategy going forward. Currently, Tampa Electric expects purchased power to meet approximately two percent of its 2018 energy needs. This energy includes contributions from the previously mentioned Pasco Cogen firm purchase.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchase 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 the wholesale power market; purchasing power on the forward market 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. Notably, the company's Pasco Cogen power agreement is from a dual-fuel resource. This allows the resource to run on either natural gas or oil, which enhances supply reliability during a potential hurricane-related disruption in natural gas supply. 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 market place.

Q. Please describe Tampa Electric's wholesale energy sales for 2017 and 2018.

A. Tampa Electric entered into various non-separated wholesale sales in 2017, and the company anticipates making additional non-separated sales during the balance of 2017 and 2018. The gains from these sales are distributed amongst Tampa Electric and its customers in accordance with the company's current incentive mechanism established in Order No. PSC-2001-2371-FOF-EI, issued on

December 7, 2001 in Docket No. 20010283-EI. The current incentive mechanism provides that all gains from non-separated sales be returned to customers through the fuel clause, up to the three-year rolling average threshold. For all gains above the three-year rolling average threshold, customers receive 80 percent and the company retains the remaining 20 percent. In 2017, Tampa Electric projected the company’s gains from non-separated sales to be below the threshold, based on six months actual and six months of projected data. However, due to favorable market conditions and results from July, the company now expects to exceed the 2017 threshold of $1,493,095. Therefore, Tampa Electric expects customers to receive 100 percent of the 2017 non-separated sales gains up to $1,493,095, and 80 percent of gains above the threshold. Based on seven months of actual and five months of projected data, the company is projected to retain approximately $15,700 in gains for the year. In 2018, the company projects gains to be $54,590, of which customers would receive 100 percent, since the amount is less than the 2018 projected three-year rolling average threshold of $881,855.

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.

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 Fuels Planning & Services.

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 October 2010, I assumed responsibility for long term fuel supply planning and procurement for Tampa Electric's generating stations.

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. 150001-EI on the subject of natural gas hedging. I have also testified before the Commission in Docket No. 120234-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 2016 results of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 011605-EI and approved by the Commission in Order No. PSC-02-1484-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 2016 Hedging Activity True-up, was prepared under my direction and supervision. This report explains the company’s risk management activities and results for the calendar year 2016.

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.

Q. What were the results of Tampa Electric’s risk management activities in 2016?

A. As outlined in Tampa Electric’s 2016 Hedging Activity True-up, filed as an exhibit to this testimony, the company follows a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. The company’s 2016 Risk Management Plan includes a financial hedging program to reduce price volatility and limit customers’ exposure to spikes in the price of natural gas. The Commission reviews and approves the Risk Management Plan each year.

Tampa Electric’s 2016 hedging activities resulted in a net settlement loss of approximately $19.3 million. These results are due to the market conditions experienced in the past year. Natural gas prices decreased significantly in late 2015 and throughout 2016 due to mild weather and abundant natural gas production which resulted in a settlement loss. However, the hedges were successful in achieving the plan objective of reducing price volatility while maintaining a reliable fuel supply.

Q. Please describe the hedging moratorium that was approved by the Commission in 2016, and the effect of that moratorium on a going forward basis?

A. On October 24, 2016, electric investor-owned utilities DEF, Gulf and Tampa Electric, collectively the IOUs, OPC, the Florida Industrial Power Users Group ("FIPUG") and the Florida Retail Federation ("FRF") 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 further called for a workshop or workshops, as soon as practicable to consider all alternatives to prospectively resolving the hedging issues, including but not limited to a risk-responsive approach, a reduction in the current levels of hedging and hedging durations, use of different financial products, or the termination of financial hedging altogether. The stated goal was either establishing a basis for the IOUs to present risk management plans for 2018 that all stakeholders could agree upon or not object to, or reaching some other mutually agreeable resolution of the hedging issues identified in Docket No. 160001-EI. The Agreement was approved by the Commission on December 5, 2016, with the issuance of Order No. PSC-16-0547-FOF-EI.

On January 10, 2017 representatives from the IOUs, Staff and intervenors attended an informal workshop at the Commission. The subject of the workshop was a presentation about the hedging proposal recommended by Staff witness Gettings in his testimony filed in the 2016 fuel docket. Mr. Gettings described his model, analysis results, and details of his proposal and answered questions from the companies and intervenors. The purpose of Mr. Gettings' four-stage hedging proposal is to mitigate price volatility while limiting hedging losses. This workshop was followed by individual meetings with the utilities and intervenors having opportunities to explore Mr. Gettings' model through questions and interaction.

A further workshop was scheduled for February 21, 2017 to allow the parties to provide feedback on the Staff proposal as well as alternative hedging proposals. The utilities presented a joint hedging proposal to use out-of-the-money ("OTM") call options instead of the previously employed swaps, as an effective method of achieving price volatility mitigation that is significantly less complex that the Gettings risk-responsive proposal and at the same tie allowing customers to participate in downward market price movements during periods of declining natural gas prices as opposed to sustaining settlement losses. Each of the IOUs provided an analysis of the costs and potential effectiveness of the OTM call option hedging strategy and answered questions about their analyses and the proposed implementation of this strategy.

Interested parties presented post-workshop comments following the February 21, 2017 workshop, and the Commission is scheduled to address the hedging issues at its April 4, 2017 Agenda Conference in Docket No. 170057-

EI. Future activities relative to hedging will depend on the outcome of that docket.

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 through the use of 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 previously used Sungard's Nucleus Risk Management System ("Nucleus"). In 2013, Tampa Electric initiated a project to replace Nucleus with Allegro. The natural gas portion of the Allegro Energy Trading and Risk Management (ETRM) project replaced Nucleus for all natural gas financial and physical transactions effective November 1, 2014. The wholesale power portion of the Allegro ETRM project replaced the in-house system on October 1, 2015. The final phase of the Allegro ETRM project went into production for solid and liquid fuels on August 1, 2016. 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. The Allegro system records all 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 2016?

A. No. Tampa Electric did not use financial hedges for commodities other than natural gas in 2016.

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 is able to obtain 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 the Commission Order No. PSC-02-1484-FOF-EI, in Docket No. 011605-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.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Portfolio Optimization.

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

A. I received a Bachelor 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, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. For the past seven years, I was responsible for long term fuel supply planning and procurement for Tampa Electric’s generating stations. As of July 2017, my responsibilities changed as I assumed the position of Director, Portfolio Optimization. I am responsible for the unit commitment of Tampa Electric’s generation assets and oversee the company’s wholesale power and gas trading activities.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe my Exhibit No. JBC-2, entitled Tampa Electric Natural Gas Hedging Activities, January 1, 2017 through July 31, 2017.

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

A. Yes, it was.

Q. Please describe your exhibit.

A. My Exhibit No. JBC-2 shows details of Tampa Electric's hedging activities for natural gas for the seven-month period January 2017 through July 2017.

Q. Does this conclude your testimony?

A. Yes, it does.

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, Portfolio Optimization.

Q. Have you previously filed testimony in Docket No. 20170001-EI?

A. Yes, I submitted direct testimony on April 3, 2017 and August 18, 2017.

Q. Has your job description, education, or professional experience changed since your most recent testimony?

A. No, it has not.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2001. In 2015, I testified in docket No. 20150001-EI on the subject of 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 ("CC") Conversion project. Most recently, I submitted written testimony in Docket No. 201700057-EI regarding natural gas financial hedging.

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. I will address steps Tampa Electric takes to manage fuel supply reliability and price volatility.

Fuel Mix and Procurement Strategies

Q. What fuels do Tampa Electric's generating stations use?

A. Tampa Electric's fuel mix includes coal, natural gas, and oil. Coal is the primary fuel for Big Bend Station, and natural gas is a secondary fuel. The Polk Unit 1 integrated combined cycle unit utilizes coal as the primary fuel and natural gas as a secondary fuel; Polk

Unit 2 CC 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) utilize natural gas. Since it serves as a backup fuel, oil consumption as a percentage of system generation is minute (*i.e.,* less than one percent). During 2017, continued low natural gas prices haves resulted in greater use of natural gas, compared to the original projection. Based upon the 2017 actual-estimate projections, the company expects 2017 total system generation to be 34 percent coal and 66 percent natural gas, with oil making up a fraction of a percentage point.

In 2018, coal-fired and natural gas-fired generation are expected to be approximately 27 percent and 72 percent of total generation, respectively. Generation from other fuel sources is expected to remain less than one percent of the 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 a large number of 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 lower costs for Tampa Electric customers.

Coal Supply Strategy

Q. Please describe Tampa Electric's solid fuel usage and procurement strategy?

A. Solid fuel is the primary fuel for the four pulverized-coal steam turbine units at Big Bend Station and the integrated gasification combined cycle Polk Unit 1. The coal-fired units at Big Bend Station are fully scrubbed for sulfur dioxide and nitrogen oxides and are designed to burn high-sulfur Illinois Basin coal. Polk Unit 1 currently burns a mix of petroleum coke and low sulfur coal. Each plant has varying operational and environmental restrictions and requires 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 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 Tampa Electric's solid fuel, coal, and petroleum coke supply through 2018.

A. In general, Tampa Electric supplies Big Bend's coal needs through a combination of shorter-term contracts and spot purchases. These shorter-term purchases allow the company to adjust supply to reflect changing coal quality and quantity needs, operational changes and pricing opportunities.

Q. Has Tampa Electric entered into coal supply transactions for 2018 delivery?

A. No, Tampa Electric is in a unique position with respect to solid fuel supply. Tampa Electric has contracts with call options for tonnage in 2018 and 2019, but the price is higher than current market prices. Therefore, Tampa Electric is in the process of securing a portion of its projected need for solid fuel for 2018 through 2020 from lower cost suppliers, and negotiations with suppliers are expected to be complete before the end of the year. These market purchases, combined with projected inventory levels, will allow the company to cover its expected solid fuel supply need for 2018.

Tampa Electric expects to have contracted for, or will have available from inventory, about 85 percent of its 2018 expected coal needs through agreements with coal suppliers. This not only ensures reliability of supply, but also mitigates price volatility. Tampa Electric anticipates the remaining solid fuel consumption for Big Bend Station and Polk Unit 1 will be procured through spot market purchases in 2018. As I discuss later in my testimony, the company will use less coal and more natural gas in 2018, compared to previous years.

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, Polk Unit 1 solid fuel is trucked to Polk Station.

Q. Why does the company maintain multiple coal transportation options in its portfolio?

A. Transportation options provide benefits to customers. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers 1) access to more potential coal suppliers providing a more competitively priced and diverse, delivered coal portfolio, 2) the opportunity to switch to either water or rail in the event of transportation breakdown or interruption on the other mode, and 3) competition for solid fuel transportation contracts for future periods.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2017 and 2018?

A. Yes. Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2017 and is evaluating how much coal to receive by rail in 2018. The evaluation depends in part on the results of the previously mentioned ongoing contract negotiations for solid fuel supply.

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 source is dependent upon quality, operational needs, and lowest overall delivered cost.

Q. Please describe the replacement for the Gulf of Mexico ("Gulf") transportation contract with a term ending in 2018.

A. Tampa Electric is in the process of securing waterborne solid fuel transportation across the Gulf of Mexico from the terminal to Big Bend Station through 2020. The company is in negotiations with a short-list of potential providers. A final contract will be in place by the end of 2017.

Q. Please describe the events that led to the need for execution of a new Gulf transportation agreement.

A. In 2014, Tampa Electric contracted with United Ocean Services ("UOS") to provide Gulf transportation for the following several years. Shortly thereafter, International Shipholding acquired United Ocean Services from United Maritime Group but Tampa Electric's arrangement with UOS was unaffected. Then, on August 1, 2016, International Shipholding and UOS filed for Chapter 11 protection under the bankruptcy laws of the United

States. In the bankruptcy process, UOS rejected Tampa Electric's agreement. Tampa Electric and UOS agreed to an amended agreement as part of the company's emergence from bankruptcy. The amended agreement includes an earlier termination, leading to the need to seek a replacement transportation agreement in 2018.

Q. Do you have any other updates to provide with regard to Tampa Electric's solid fuel transportation portfolio?

A. Tampa Electric's "open" position for solid fuel and Gulf transportation, along with other operational and market factors, allows the company to use more natural gas in Big Bend Units 1 and 2. As a result, Tampa Electric will contract for fewer tons of solid fuel supply and Gulf transportation in the remainder of 2017 and 2018, than it would have otherwise. This change will allow Tampa Electric to utilize low-cost natural gas-fired generation and provides projected fuel savings to Tampa Electric's customers for the period July 2017 through December 2018.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2018 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. New or pending environmental regulations may affect the types of coal, the quantities of coal that can be consumed at the stations or, most likely, both. Also, the use of different types of fuel within the state continue to evolve as generation assets are built, upgraded or retired. For instance, Tampa Electric's Polk Unit 2 CC entered service in January 2017. The Polk Unit 2 CC project converted the existing natural gas combustion turbines at Polk Power Station into a very efficient natural gas combined cycle unit. Similarly, several new natural gas combined cycle units have been built within the state during the past several years. Depending on the relative price of delivered solid fuel, delivered natural gas and the dynamics of the wholesale power market, the actual quantity of solid fuel burned may vary significantly each year. Tampa Electric strives to balance the need to have reliable solid fuel commodity 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. Similar to 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 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 approved 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 tools 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. Additionally, Tampa Electric risk management activities reduce natural gas price volatility.

Q. Please describe Tampa Electric's diversified natural gas transportation agreements.

A. Tampa Electric receives natural gas via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. The ability to deliver natural gas directly from two 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 to support the aero-derivative combustion turbines and natural gas co-firing in the coal units. Polk Station receives natural gas from FGT to support Polk Unit 2 CC and, as an alternate fuel, Polk Unit 1.

Q. Are there any significant changes to Tampa Electric's expected natural gas usage?

A. Tampa Electric's Big Bend Station coal-fired units can be fueled with natural gas for ignition, reliability, emissions control, and power generation. As such, Tampa Electric is seeking to maximize its existing pipeline capacity and burning natural gas to the extent that there is available capacity. For the balance of 2017 and during 2018, Big Bend Units 1 and 2 are projected to be fueled by natural gas only. This opportunity has emerged as the result of continued low natural gas prices, the open coal supply and transportation portfolio positions, and available natural gas pipeline capacity to the station. The company projects that this change will result in fuel savings, as I stated earlier in my testimony.

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. Currently, the company reserves 1,250,000 MMBtu of long-term storage capacity and has 250,000 MMBtu of shorter-term storage capacity.

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 the Transco lateral. SESH and the Transco lateral connect the receipt points of FGT and other Mobile Bay area pipelines with natural gas supply in the mid-continent. Mid-continent natural gas production has grown and continues to increase. Thus, SESH and Transco lateral give Tampa Electric access to secure, competitively priced on-shore gas supply for a portion of its portfolio.

Q. Has Tampa Electric acquired additional natural gas transportation for 2017 and 2018 due to greater use of natural gas at Big Bend Station?

A. No. Tampa Electric has not acquired additional long-term firm pipeline capacity for 2017 and 2018 due to greater use of natural gas at Big Bend Station. The company continues to supplement its existing transportation portfolio with near-term daily transportation to support the incremental natural gas burn on its system, including in Big Bend Units 1 and 2. Nonetheless, with its growing dependence on natural gas, the company continues to monitor the interstate pipeline market for attractive opportunities to secure long-term, firm pipeline capacity. While there is daily transportation capacity to support operation of Big Bend Units 1 and 2 on natural gas, there is not sufficient spare capacity to support additional gas usage at Big Bend Station.

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, 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.

Projected 2018 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 2017, 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. 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 2018 projected fuel prices compare to the fuel prices projected for 2017?

A. The commodity price for natural gas during 2018 is projected to be slightly lower ($3.13 per MMBtu) than the 2017 projected price ($3.17 per MMBtu). The market price for natural gas in 2018 is expected to be similar to the prices projected in 2017.

The 2018 coal commodity price projection is slightly higher ($35.80 per ton) than the price projected for 2017 ($30.88 per ton) during preparation of the 2017 fuel clause factor. Production cuts and growing international demand for coal have put some upward pressure on coal prices.

Risk Management Activities

Q. Please describe Tampa Electric's risk management activities?

A. On October 24, 2016 electric investor-owned utilities Duke Energy Florida, Gulf Power 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% 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 further called for a workshop or workshops, as soon as practicable to consider all alternatives to prospectively resolving the hedging issues, including but not limited to the Gettings approach, a reduction in the current levels of hedging and hedging durations, use of different financial products, or the termination of financial hedging altogether. The stated goal was either establishing a basis for the IOUs to present risk management plans for 2018 that all stakeholders could agree upon or not object to, or reaching some other mutually agreeable resolution of the hedging issues identified in Docket No. 20160001-EI. The Agreement was approved by the Commission on December 5, 2016, with the issuance of Order No. PSC-2016-0547-FOF-EI. The Commission, by Order No. PSC-2017-0134-PCO-EI, issued April 13, 2017 in Docket No. 20170001-EI, subsequently determined the IOUs would not have to file a Risk Management Plan for 2018 because an evidentiary hearing on hedging will be held September 27-28, 2017 in Docket No. 20170057-EI. This order effectively extended the hedging moratorium until a decision is reached in Docket

No. 20170057-EI. A low number of natural gas financial hedges equating to a relatively small volume remain from the hedging activities prior to the moratorium. Those financial hedges were placed in accordance with the company's Commission-approved Risk Management Plan.

Q. Were Tampa Electric's efforts through July 31, 2017 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes, Tampa Electric has executed hedges according to the Risk Management Plan approved by the company's Risk Authorizing Committee and filed with the Commission. On April 3, 2017, the company filed its 2016 Natural Gas Hedging Activities Report. Additionally, utilities must submit a Natural Gas Hedging Activity Report showing the results of hedging activities from January through July of the current year. The Hedging Activity Report facilitates prudence reviews through July 31st of the current year and allows for the Commission's prudence determination at the annual fuel hearing. Tampa Electric filed its Natural Gas Hedging Activities Report in this docket on August 18, 2017. The report shows the results of the company's prudent hedging activities from January through July 2017. The company executed hedges for a smaller volume of expected usage than stated in its Risk Management Plan for this period due to the 2016 agreement for a hedging moratorium, as I discussed above.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF SIMON O. OJADA

DOCKET NO. 20170001-EI

SEPTEMBER 18, 2017

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, and 20160001-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. 20170001-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 15, 2017. 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 under my direction.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

We obtained DEF's supporting detail of the hedging settlements for the 12 months ended July 31, 2017. 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. No exceptions were noted.

Gains and Losses

We reconciled the monthly balances of hedging transactions from DEF's Hedging Details Report for the period August 1, 2016, through July 31, 2017, to its Hedging Summary by Commodity Reports for 2016 and 2017. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We selected 22 natural gas hedging transactions from August 2016 through July 2017 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. Compliance with the 2016 Risk Management Plan was tested in Docket 20160001-EI. The 2017 Risk Management Plan was withdrawn by the Utility. 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, 2016, for the Regulated Fuels Inventory Management Process and the Regulated Trading Cycle. There was no external audit 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.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF DONNA D. BROWN

DOCKET NO. 20170001-EI

SEPTEMBER 18, 2017

Q. Please state your name and business address.

A. My name is Donna D. Brown and my business address is 2540 Shumard Oak Boulevard, Tallahassee, FL 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 February 2008.

Q. Briefly review your educational and professional background.

A. I graduated from Florida A&M University's School of Business & Industry in 2006 with a Bachelor of Science Degree in Accounting.

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 presented testimony before this Commission?

A. Yes. I filed testimony in the Fuel and Purchased Power Cost Recovery Clause, Docket Nos. 20110001-EI, 20120001-EI, and 20160001-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 Florida Power & Light Company (FPL or Utility) which addresses the Utility's filing in Docket No.

20170001-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 15, 2017. This report is filed with my testimony and is identified as Exhibit DDB-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared under my direction.

Q. Please describe the work you performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

We obtained FPL's supporting detail of the hedging settlements for the twelve months ended July 31, 2017. The support documentation was traced to the general ledger transaction detail. We verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

We traced the monthly balances of hedging transactions from FPL's April 3, 2017 and August 18, 2017 filings in this docket for the period August 1, 2016 to July 31, 2017 to FPL's Derivative Settlement Report. We selected various hedging transactions from various counterparties from August 2016, December 2016, February 2017, and April 2017 for natural gas as a sample and traced them from the Derivative Settlement Report to the invoices, purchase statements, confirmation notices and deal tickets. FPL does not have any tolling agreements where natural gas is provided to generators under purchase power agreements. We recalculated the gains and losses. We compared these recalculated gains and losses with FPL's journal entries for realized gains and losses. We compared a sample of the purchase prices to the futures rates published by the NYMEX Henry Hub gas futures contract rates. We traced a sample of settlement prices to the futures rates 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. We also obtained FPL's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the twelve months ended July 31, 2017, and compared August 2016 through December 2016 to 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 verified the separation of duties during our testing of transactions by agreeing the names of various employees from deal tickets and confirmations to FPL's procedures. We requested internal and external audits that related to hedging activities for the period August 1, 2016 to July 31, 2017. The Utility stated there were none. No exceptions were noted.

Q. Please review the audit findings in this audit report.

A. There were no findings in this audit related to hedging activities.

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF GEORGE SIMMONS

DOCKET NO. 20170001-EI

SEPTEMBER 18, 2017

Q. Please state your name and business address.

A. My name is George Simmons. 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 November 2013.

Q. Briefly review your educational and professional background.

A. I graduated from Florida A&M University's School of Business & Industry in 2013 with a Bachelor of Science Degree in Accounting.

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 No. 20150001-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. 20170001-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 15, 2017. This report is filed with my testimony and is identified as Exhibit GS-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared under my direction.

Q. Please describe the work you performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

We obtained Gulf's supporting detail of the hedging settlements for the twelve months ended July 31, 2017. 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. No exceptions were noted.

Gains and Losses

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, 2016 to July 31, 2017. 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, 2017, and compared August 2016 through December 2016 to the Utility's 2016 Risk Management Plan. Audit staff could not compare January 2017 through July 2017 to the 2017 Risk Management Plan as it was withdrawn. No exceptions were noted.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. We requested internal and external audit reports from August 1, 2016 to July 31, 2017 and noted that none pertained to fuel hedging program. 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.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF INTESAR TERKAWI

DOCKET NO. 20170001-EI

SEPTEMBER 18, 2017

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 and an Enrolled Tax Agent.

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, and 20160001-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. 20170001-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 15, 2017. 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 under my direction.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

I reviewed TECO's supporting detail of the hedging settlements for the twelve months ended July 31, 2017. I traced the transactions to the general ledger and trade confirmation documents. I verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

I 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, 2016, to July 31, 2017. I selected all gas hedging transactions for September and October 2016 and traced them from the Mark to Market Position Report to the third-party confirmation notices and contracts. I traced a sample of the purchase prices to the Gas Daily – NYMEX Henry Hub gas futures contract rates. I traced the related settlements prices to the Gas Daily – NYMEX Henry Hub gas futures contract rate. I 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 the year ended July 31, 2017, and compared August 2016 through December 2016 to the Utility's 2016 Risk Management Plan. Audit Staff could not compare January 2017 through July 2017 to the 2017 Risk Management Plan as it is withdrawn. No exceptions were noted.

Separation of Duties

I 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.

CHAIRMAN BROWN: Now on to exhibits.

MS. BROWNLESS: Yes, ma'am.

Staff has compiled a stipulated comprehensive exhibit list, which includes the prefiled exhibits attached to each witness' testimony as well as staff's Exhibits 74 through 99. The list has been provided to the parties, to the Commissioners and to the court reporter.

And at this time, we would request the comprehensive exhibit list be marked for identification as Exhibit No. 1, and that the other exhibits be marked for identification as set forth on the comprehensive exhibit list.

CHAIRMAN BROWN: We will go ahead and do that at this time.

(Whereupon, Exhibit No. 1 was marked for identification.)

(Whereupon, Exhibit Nos. 1-99 were marked for identification.)

MS. BROWNLESS: Thank you.

At this time, we would request that the comprehensive exhibit list be entered into the record.

CHAIRMAN BROWN: Okay. Seeing no

objections from the parties, we will go ahead and enter into the record the comprehensive exhibit list identified as Exhibit 1.

(Whereupon, Exhibit No. 1 was received into evidence.)

MS. BROWNLESS: Thank you, ma'am.

At this time, we would request that the stipulated prefiled witness exhibits, Nos. 2 through 27 and 45 through 77 be entered into the record.

CHAIRMAN BROWN: Do any of the parties have any objections? Seeing none, we will go ahead and enter into the record Exhibits 2 through 27 as well as 45 through 77.

MS. BROWNLESS: Thank you, ma'am.

(Whereupon, Exhibit Nos. 2-27 & 45-77 were received into evidence.)

MS. BROWNLESS: And we would also request that the stipulated staff exhibits, Nos. 78 through 99, be entered into the record.

CHAIRMAN BROWN: All right. Are there any objections? Seeing none, we will go ahead and enter into the record Exhibits No. 78 through 99.

MS. BROWNLESS: Thank you, ma'am.

(Whereupon, Exhibit Nos. 78-99 were received into evidence.)

CHAIRMAN BROWN: All right. Okay. Staff, is this docket in a posture to make a bench decision on the stipulated issues?

MS. BROWNLESS: Yes, ma'am, if the Commission determines that a bench decision is appropriate.

CHAIRMAN BROWN: Okay. Commissioners, are there any questions regarding the proposed stipulations? They have been identified as provided by staff just earlier.

MS. BROWNLESS: Yes, ma'am. We can tell you the Type 2 stipulations are on page 31 through 61 of the prehearing order, and they are Issues 1B, 2B through 2I, 2Q, 2R, 3A, 6 through 11, 13A, 16 through 22, 23A, 24A through 24D and 27 through 36.

CHAIRMAN BROWN: Thank you for going through that.

Commissioners, any questions on the stipulations?

Commissioner Polmann.

COMMISSIONER POLMANN: Thank you, Madam Chairman. If you are -- if you are ready, I will make a motion.

CHAIRMAN BROWN: I have no other lights on, so I think we are ready for a motion.

COMMISSIONER POLMANN: Thank you.

I would move that the proposed Type 2 stipulations that were recited by staff and listed on pages 31 to 61 of the prehearing order be approved.

CHAIRMAN BROWN: Is there a second?

COMMISSIONER BRISÉ: Second.

CHAIRMAN BROWN: Any further discussion?

Seeing none, all those in favor, say aye.

(Chorus of ayes.)

CHAIRMAN BROWN: Opposed?

Stipulations pass unanimously.

Now to the contested issues.

MS. BROWNLESS: Yes, ma'am. The first set of contested issues are the hedging issues. Those are issues 1A, 2A, 4A and 5A. These are listed on pages 9, 10, 17 and 18 of the prehearing order.

While OPC, FIPUG and FRF have taken positions on these issues contrary to the positions of the IOUs, they have agreed to waive cross-examination and briefing on these issues, and do not object to a bench vote being taken.

And at this time, I would like to confirm that that is the position of the parties.

CHAIRMAN BROWN: Parties. I was going to confirm it.

MR. MOYLE: FIPUG has waived a lot of things relating to hedging, but -- but we would like to make use of our brief allotted time to make some comments, with the exception of an opening statement, I think we can concur with that. We don't feel a need to file a brief, but we do want to visit with the Commission briefly on hedging.

CHAIRMAN BROWN: And the brief that you plan on filing on --

MR. MOYLE: Would be on the SoBRA issues, not on -- not on the hedging issues.

CHAIRMAN BROWN: FPL.

MR. BUTLER: The stipulation is fine with me. I am a little surprised that FIPUG is choosing to have part of its opening statement on the issues in view of the fact that we have the witnesses stipulated, and I had understood that, you know, there wasn't going to be further proceedings; but if Mr. Moyle wants to comment, I would like to reserve a brief period of time to respond to his comments, if necessary.

CHAIRMAN BROWN: Absolutely. Fair enough.

Okay, anybody else?

MR. WRIGHT: We concur with a waiver of cross, waiver of briefing, and that we have no objection to taking the bench vote on the hedging issues.

CHAIRMAN BROWN: Thank you, Mr. Wright.

OPC.

MR. SAYLER: Yes, ma'am. Same as FRF, we waived our cross, briefing. We did have a very, very brief opening at the appropriate time, and that's it for us.

CHAIRMAN BROWN: Wait, pardon me, can you repeat that last --

MR. SAYLER: There is a brief opening statement --

CHAIRMAN BROWN: Okay.

MR. SAYLER: -- that's reserved for the parties who are not contesting SoBRA, so at the appropriate time.

CHAIRMAN BROWN: Yes, a couple minutes.

That sounds good.
All right, staff.
MS. BROWNLESS: Yes, ma'am. I don't know if the parties would like to take opening statements and use their three minutes to talk about hedging first before we ask that there be a vote, or that we field questions --
CHAIRMAN BROWN: I think that -- that seems more appropriate.
Are you all amenable to that?
MR. SAYLER: Yes.
MR. WRIGHT: That's a great idea.
CHAIRMAN BROWN: Okay. So maybe we just take that out of order and take that now.
MS. BROWNLESS: Sure. Yes, ma'am.
CHAIRMAN BROWN: All right. So let me go through that. It's my understanding that you all want to make opening statements, and the overview of the time allotments per the prehearing officer, opening statements limited to three minutes per party for non-SoBRA issues. Florida Power & Light and FIPUG have an additional 10 minutes, total 13 minutes for each, on issues 2J through 2P.
And we will start with Florida Power &

Light.

MR. BUTLER: Madam Chairman, just to be sure I understand the way you want to proceed. Will Cox is prepared to provide you an opening statement with respect to the SoBRA issues, that's probably quite a bit longer than I would spend talking about the hedging issues. Does it make sense to have opening statements just initially on the hedging issues and then --

CHAIRMAN BROWN: That's a great idea.

MR. BUTLER: -- return to the SoBRA?

CHAIRMAN BROWN: Mr. Butler, good idea.

MR. BUTLER: Thank you.

CHAIRMAN BROWN: Let's do that.

MR. BUTLER: Okay. With that, as I said earlier, I don't really have anything prepared in advance. I would like to reserve the opportunity to respond to whatever Mr. Moyle and Mr. Sayler have to say.

CHAIRMAN BROWN: Okay.

MR. BUTLER: Thank you.

MR. MOYLE: I do have a few comment, but I will tell you, Mr. Butler and I have known each other a long time. My first clerking job --

CHAIRMAN BROWN: Is this going in your

opening statements?

MR. MOYLE: I hope not. I was going -- I was going to say, I clerked for Mr. Butler, and he is a very good lawyer, and here he has managed to make me go first with respect to my -- to my comments --

CHAIRMAN BROWN: A little savvy.

MR. MOYLE: -- on hedging, so touché, Mr. Butler. Nicely done, anyway.

So we do want to take a few minutes that hopefully doesn't include my opening procedural remarks, and just talk about hedging.

We -- we -- FIPUG has maintained a position for many years that we don't think hedging is appropriate. And the question that was asked before you is did -- did FPL prudently implement their hedging plans, and we've said no because the fundamental underlying premise is we don't think hedging, you know, is needed, and is it has not worked out well for the customers. I think at last count, the total losses for the hedging program is close to $7 billion, and we have asked, and would ask again, that hedging go away.

It now is the subject of three settlement agreements that you have approved, where we have said no hedging; and in the fourth settlement agreement, there is a provision that also would do away with hedging.

And the you have -- you have a pending hedging docket that's been postponed. I think Commissioner Brisé is the prehearing officer. And I would encourage you all to, given the status of the settlements, to just say we don't really need to handle this now; because if you do go to hearing, you are going to be getting facts that will be stale by the time anybody could implement it, because you are going to have these settlements for three or four years, and they are contractually precluded from hedging.

So we would -- we would urge you to take this opportunity to say it probably doesn't make a lot of sense to continue with the hedging conversation, and, you know, given the way this process works and the procedures that -- I thought this was a good time to bring that up.

I do have an exhibit that I am going to use when we are talking about SoBRA, that I think --

CHAIRMAN BROWN: We are not on SoBRA.

MR. MOYLE: No, but it's relevant also to hedging.

Yesterday, there is a story that the Trump administration plans the largest oil and gas lease in U.S. history. And it talks about that there is going to be a lease, it's estimated to have 141 trillion cubic feet of natural gas associated with it. The Secretary of the Interior is quoted as saying, in today's low price energy environment.

So the point that we are making, and have made, is this isn't a market where we need to hedge. So we wanted to kind of take an opportunity to just encourage you all to finish the hedging discussion and close that other docket and let us -- let us move forward.

So that was the opening comments I wanted to make. Thanks for the opportunity to do so.

CHAIRMAN BROWN: Thank you, Mr. Moyle.

Mr. Butler, if you want, we will go down the aisle here and then we will come back to you.

MR. BUTLER: That would be my preference, yes, please.

CHAIRMAN BROWN: Mr. Wright.

MR. WRIGHT: Thank you, Madam Chairman, and I will be very brief.

Like FIPUG, like the Public Counsel, the Florida Retail Federation has consistently opposed hedging for a long, long time. The evidence is clear and overwhelming, hedging has not been in the best interest of Florida's electric customers. We are very grateful that all four of the investor-owned utilities have agreed with us in settlements to suspend hedging for periods of four and five years. We are grateful that you have approved three of those, and we look forward to your approval of the Tampa Electric settlement in a couple of weeks.

But given the way the -- we didn't want to hold this process up, and that's why we've agreed to take the position and to waive cross, and waive briefing on this issue. We didn't want to hold this process up.

Hedging is, for all practical purposes, going to stop for four or five years. The way the issue was framed, however, it asked us --

and you have seen, we've probably joined in 475 Type 2 stipulations over the last two years on various issues. We could not agree to stipulate to any statement, or even not to take a position that said, yes, it was prudent for the utilities to do it. It was not prudent, in our view of the world, for the utilities to continue hedging over these last 15 years when we've known how poorly it was performing, vis-a-vis, the utilities customers.

That's why we took the positions we took. We are glad that the settlements are going into effect that will suspend hedging for periods of time. I just wanted you to have that explanation of why we insisted on maintaining our adverse positions, but we are entirely willing to waive cross, waive briefing and have a bench vote just noting that we've formally objected.

Thank you.

CHAIRMAN BROWN: Thank you. And thank you for stating that on the record.

Office of Public Counsel.

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

I also want to say thank you to the staff and all the other parties for working together on this docket this year. It's always been a pleasure.

We note from, the Public Counsel's standpoint, that natural gas hedging has been a highly contested issue in the 2015 and 2016 dockets, and still remains a contested issue in this docket. I am not going to repeat the comments of FRF or FIPUG, but Public Counsel does echo those, as well as the reasons why we waived cross and briefing on the issue of hedging.

We do note that with the approval of the comprehensive rate settlements for FPL, Gulf and Duke even today, and also the pending settlement approval for TECO on November 6th, natural gas hedging activities are, in effect, suspended.

So with that, we have no further comments at this time. Thank you.

CHAIRMAN BROWN: Thank you.

FPL.

MR. BUTLER: Thank you, Madam Chairman.

I would put the opening statement comments in kind of the posture of being a prequel. I think that the Commission intends, at some point, when appropriate, to visit the issues of hedging policy, should you choose, and we would certainly participate in any proceeding to that effect. I don't think that's what the Issue 2A, or the others that have been identified as contested by these parties are about.

For FPL, we, consistent with our 2016 rate case settlement on -- stopped placing any future hedges pretty much the day that the settlement agreement was approved. You know, the issues here really are about the prudence of actions taken while we were hedging under approved risk management plans that we had previously submitted, and no parties had objected to their approval. They were approved by the Commission.

All that the prudence determination involves here is an assessment that we acted appropriately under our approved risk management plans. Your staff has audited, concluded that we acted appropriately within the scope of the risk management plans, and in that sense, the hedging certainly was prudent, and we ask you to approve it as such.

We agree that we are in a moratorium period in which we are not placing any future hedges, and would not be doing so until the moratorium ends, and presumably by that point there will have been further discussion on appropriateness of hedging at all, and if appropriate the form of it. But I think that issue is something that really isn't before the Commission for decision in this proceeding.

Thank you.

CHAIRMAN BROWN: Thank you.

Mr. Moyle, I heard your microphone go on.

MR. MOYLE: I think I left -- I left it on and was turning it off, but I would just --

CHAIRMAN BROWN: No. No. No. No.

MR. MOYLE: That's the trick Mr. Butler taught me.

I don't know that we are really saying don't approve the hedging that they are seeking. I think we are, you know, asking you, as a commission, which I think you have the prerogative to do, is say, please, please --

CHAIRMAN BROWN: All right.

MR. MOYLE: -- take action on the

underlying --

CHAIRMAN BROWN: All right. Mr. Beasley.

MR. BEASLEY: Yes, Madam Chair.

I would adopt the comments Mr. Butler made on behalf of Tampa Electric Company, and ask that the company's position, Tampa Electric's position on Issue 5A be approved.

CHAIRMAN BROWN: Thank you.

MR. BADDERS: I would do the same for Gulf. I concur with the comments, and I would ask that you approve the issue related to Gulf's hedging.

CHAIRMAN BROWN: Thank you.

FPUC.

MS. KEATING: Fortunately or unfortunately, FPUC does not have a hedging plan so --

CHAIRMAN BROWN: All right. So we are dealing with the contested -- am I missing something? Who am I missing? I'm sorry.

MR. BERNIER: I will be happy to add my voice to the chorus and ask to you approve our Issue 1A. Thank you.

CHAIRMAN BROWN: Thank you. You are out of order in my direction here, so my a apologies.

All right. Now we are going to get to the contested issues of 1A, 2A, 4A, 5A, listed on pages nine, 10, 11 -- nine, 10, 17 and 18 of the prehearing order, Commissioners.

Now is the time to ask any questions you may have of the parties or staff. I.

Have a question for staff regarding Mr. Moyle's opening comments regarding the hedging docket.

What is staff going to do with that docket? Let's say, hypothetically, that the Tampa Electric docket gets approved, or settlement agreement gets approved in two weeks, what are you going to do with the hedging docket?

MS. BROWNLESS: Well, we are going to wait for the TECO settlement agreement to be voted on, as the parties have alluded to here. That will be the last IOU who's currently hedging that will have a hedging moratorium in place, and then we are going to reassess the docket and figure out what to do at that time.

CHAIRMAN BROWN: A good answer. Thank you.

All right, Commissioners, any other questions?

We are ripe for a motion on Issues 1A, 2A, 4A and 5A.

Commissioner Brisé.

COMMISSIONER BRISÉ: Thank you, Madam Chair.

And having reviewed the information that has been provided, I move that we approve Issues 1A, 2A, 4A and 5A, and that's my motion.

CHAIRMAN BROWN: Okay. Is there a second?

COMMISSIONER GRAHAM: Second.

CHAIRMAN BROWN: Is there further discussion on the motion?

Seeing none, all those in favor, say aye.

(Chorus of ayes.)

CHAIRMAN BROWN: Opposed?

Motion passes unanimously.

I will note that the parties whose issues have been resolved may be excused from the remainder at this time, so, good-bye. Have a great day. We will still be here.

All right.

MS. BROWNLESS: Madam Chair, in order to clarify the record, we just want to note that the positions of the companies with regard to 1A, 2A, 4A and 5A have been approved by your motion.

CHAIRMAN BROWN: We know that.

MS. BROWNLESS: Thank you.

CHAIRMAN BROWN: You made the motion, we voted on that.

MS. BROWNLESS: Okay.

CHAIRMAN BROWN: Thank you.

All right. We are going to go to the contested issues.

Staff, are there any preliminary matters remaining with the remaining contested issues?

MS. BROWNLESS: No, ma'am. The contested issues are listed on pages 13 through 16 of the prehearing order.

CHAIRMAN BROWN: Okay. Commissioners, that is identified as Issues 2J through 2P, and it's listed in the prehearing order.

Are there any other preliminary matters of the parties on the contested issues?

Seeing none, I will go over the overview of the opening statements while counsel is getting ready.

As I mentioned earlier, we already

addressed the three minutes on the non-SoBRA issues, so Florida Power & Light has an additional 10 minutes here to give us opening statements on the SoBRA Issues 2J through 2P, FIPUG, as well, has an extra 10 minutes. Retail Federation and Public Counsel are not going to give opening statements on those issues.

So we can go -- if counsel for Florida Power & Light is ready.

MR. COX: We are ready. Thank you.

CHAIRMAN BROWN: You have 10 minutes.

MR. COX: Thank you. Madam Chairman, Commissioners, Will Cox on behalf of Florida Power & Light. With me is Maria Moncada.

With this petition, Florida Power & Light requests approval for its 2017 and 2018 solar energy centers, which cost recovery was authorized by the Commission in its approval of the stipulation settlement of FPL's 2016 rate filing subject to meeting specific requirements for costs and cost-effectiveness.

Each of the eight solar energy centers that FPL is building in 2017 and 2018 has now put out 74-and-a-half megawatts, together these eight new solar energy centers will provide nearly 600 megawatts of clean, cost-effective solar power to serve our customers, and provide substantial cost savings over the long-term once they are operational in 2018, powering the equivalent of approximately 120,000 homes across our service territory.

Under the 2016 rate settlement order, the Commission authorized FPL to construct up to 300 megawatts of new solar generation for each of the four years, 2017 through 2020, of the rate settlement period if FPL satisfies the following requirements for the requested solar based rate adjustments, or SoBRAs.

First, the solar projects must be cost effective. Second the total cost of the solar energy centers must not exceed $1,750 per kilowatt. And third, the construction, engineering and component costs for the solar projects must be reasonable.

Through the testimonies of FPL Juan Enjamio and William Brannen, who will testify before you today, FPL will demonstrate that an FPL generation resource plan with these 2017 and 2018 projects is cost-effective with as much as $106 million in lower costs compared to a status quo plan without the additional solar generation.

The result will be real and significant savings for our customers due to fuel savings and reduced emissions, not to mention the creation of new jobs and additional tax revenues that these projects will provide to local communities across our service territory.

Mr. Brannen will also testify that the 2017 and 2018 project costs are significantly below the $1,750 per kilowatt cost threshold from the rate settlement agreement, and that FPL further ensure that these costs are reasonable by utilizing significant competitive bidding processes to procure equipment and to engineer and construct these projects at the lowest cost.

FPL witness Liz Fuentes provides a calculation of the appropriate revenue requirements for the 2017 and 2018 SoBRAs consistent with the rate settlement approval order. And witness Tiffany Cohen provides the calculation of the appropriate SoBRA factor for cost recovery and other revenue requirements for these solar projects.

Chairman Brown, Commissioners, FPL's 2017 and 2018 projects are cost-effective, and they reflect reasonable construction, engineering and component costs that are low the $1,750 per kW cost threshold. All consistent with the rate settlement order.

Therefore, FPL would request approval of its petition and a specified base rate increase is recover the revenue requirements for these projects. If approved, the SoBRA factor for the 2017 project will be applied to our customers' bills upon commercial operation date much the project, which is expected by January 1st of 2018. In the 2018 project, SoBRA factor will be applied upon the commercial operation date of the 2018 project, which is expected by March 1st of 2018.

FPL looks forward to bringing these projects into service, increasing our renewable energy generation portfolio and providing our customers with a significant source of clean and cost-effective energy.

We thank you for this opportunity to present an opening statement on behalf of FPL for our inaugural SoBRA filing.

CHAIRMAN BROWN: Thank you.

All right. Mr. Moyle.

MR. MOYLE: Thank you.

And thank you in advance for taking some time today to hear about the SoBRA issue. You have seen them in some settlement agreements. You have asked questions, but I don't think you have had -- had an opportunity for a contested SoBRA discussion, and so I look forward to -- to asking questions, and think I making some points -- underscoring some points I want to make in my opening statement.

Let me be clear about FIPUG's position with respect to renewable energy and solar energy, which is we support cost-effective needed renewable energy. We don't support renewable energy that FPL is proposing, or that a utility is proposing that is not needed, and that is not cost-effective. So I think the questions that you will have to wrestle with is, are these needed, number one? And are they -- are they cost-effective?

Now, you will see some evidence with respect to how they come up with the cost-effectiveness number. FPL says, oh, we are going to save $39 million over 30 or 33 years in one scenario. And that's a scenario where you have, I think, medium -- medium gas prices and medium cost of carbon, okay. But in other scenarios, when you look at -- at low cost of carbon, carbon has never been taxed in the state of Florida, or -- or there has been no federal carbon tax. I think the witnesses will admit that, yeah, carbon doesn't have a cost.

If you make that assumption, and you also assume that the gas prices are going to remain either at a medium or low level, this -- this -- this dog doesn't hunt in terms of it's cost ratepayers money. So the cost-effectiveness that required to prove cannot be proved if you make the, what we would argue, is the more reasonable assumption about the cost of carbon and -- and the availability and projected cost of -- of natural gas.

You know, the state -- I mean, the country has a lot of natural gas available. And as I alluded to a minute ago, the Trump administration is offering leases that will make -- make a lot more available.

The cost of carbon -- I mean, this -- this administration is supporting the reintroduction of coal, and -- and is not going to impose a carbon tax.

So when -- you will see some information, we have an exhibit that shows you the various options. So you will hear about 39 million, 39 million, yeah, that's under certain assumptions. But if you make, you know, some different assumptions, it's a -- it's a money loser. So I wanted to make that point real clear.

The other thing is, and I am fond of car analogies, as you all who have served on the Commission for a number of years know, and I am not going to miss the chance to make a car analogy here.

If -- if you have -- have a family that has three people in it, and all three people have a car, and a car is running and it works, and it's paid for, and it gets you from point A to point B, and you don't have a need for another car, you shouldn't go out and spend your money on another -- another car, and that is a similar situation with FPL.

You guys have a rule -- the Commission has a rule with respect to reserve margin that says, you should plan for a 15-percent reserve margin. There is also a stipulation that was entered into that has a 20-percent reserve margin.

I think, when asking these witnesses questions, and showing them documents, that we will establish that -- that the company is already over 20 percent, and that the solar just adds on top of 20 percent.

So it's taking them above the 20 percent reserve margin. Arguably, it's not needed. And in this day and age, you know, with the recent events of the hurricanes, and things like that, you guys don't have many opportunities to give ratepayers rate relief. You know, the Legislature often looks to provide tax relief. And I would encourage you all, when you have opportunities, to provide some rate relief.

So just because, you know, this was something that -- that was agreed to in a settlement agreement -- which FIPUG did not sign on to that settlement agreement -- does not mean that you are -- you got to go with it, that you are compelled to grant their petition.

We would -- we would say that, you know, that you are not, and that you should look at these facts and the arguments I am making about it not being needed, and that it could cost money, more likely than not, with the right assumptions, we think, should compel you to -- to not allow the ratepayers to get -- get hit with this increased rate increase that FPL is -- is now seeking.

One -- one other point that I am going to spend a little bit of time on, and I think it might help with the discussion, just to lay it out. There is a bid rule that the Commission has, that requires utilities to go and seek requests for proposals for any power plant that is 75 megawatts or greater. There is a need determination that's in the statutes for 75 megawatts, when somebody comes in and files for a power plant, even a solar plant of 75 megawatts or greater, they have to go through a need determination, and part of that is to go and solicit bids from third parties.

You heard FPL's lawyer in their opening say, well, you know, you should be comforted because we've -- we've sought competitive procurement on EPC contracts, engineering, procurement, construction. But we would suggest that you also send a message that they ought to go out and seek competitive bids from people who are in the business.

The earlier proceeding, you heard from a gentleman representing solar developers. We will have an exhibit that, I think, references someone who was trying to provide some -- some solar to FPL. And we don't -- as FIPUG, we don't really care whether FPL builds it, or whether a third-party builds it. We think there should be an opportunity for the competitive forces to be brought to bear, because we want the lowest, most inexpensive solar that -- that can be provided -- again, if it's needed, if it's needed -- and we think the competitive market forces should be brought -- brought to bear.

So we will ask some questions about why did you size it at 74.5? Was that to, you know, not have to go through the competitive bidding process? And -- and we'll see what -- what the responses are to that.

So, Madam Chairman, thank you for the opportunity to make some -- to make some opening remarks, and we look forward to having -- having the conversation with the witnesses.

CHAIRMAN BROWN: Thank you. Thank you to both the parties.

All right. We are going to just get through some procedural matters on the witnesses and this process.

As you know, the standard for providing irrelevant, immaterial or unduly repetitious evidence will be excluded. I just want to remind to the parties of that.

And I would also like to reminds you that before you begin conducting your cross-examination of a witness -- we only have two today in this docket -- please provide our staff, to the extent that you can, the exhibits in advance, collated copies of all cross-examination exhibits that you plan to use. We can instruct the witness to turn them over, if you would like, but that helps make this process much more efficient.

Witnesses will be permitted up to five minutes to summarize their opening statement -- or testimony, and prefiled testimony will be entered at the beginning of the witness' testimony, and we'll admit exhibits at the conclusion.

Order of cross, as is follows: OPC, FIPUG -- pardon me, OPC, FRF, if you have any, FIPUG and then staff, Commissioners and redirect. So that's the format that we are going to do.

And so at this time, I will be swearing in all of the witnesses in the 01 docket. If you could, please stand with me and raise your right hand.

(Whereupon, witnesses for the 01 docket were sworn.)

CHAIRMAN BROWN: Thank you. Please be seated.

Florida Power & Light.

MR. COX: Yes, Chairman Brown, FPL calls its first witness, Juan Enjamio.

CHAIRMAN BROWN: Can you pronounce that one more time?

MR. COX: Juan Enjamio.

CHAIRMAN BROWN: Enjamio.

MR. COX: Enjamio.

CHAIRMAN BROWN: Thank you.

MR. COX: And I will let him correct me if I didn't do it justice.

CHAIR BROWN: Good afternoon.

THE WITNESS: Good afternoon, Chairman Brown.

CHAIRMAN BROWN: It is Enjamio?

THE WITNESS: Enjamio, perfect.

CHAIRMAN BROWN: I like it.

Whereupon,

JUAN ENJAMIO

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

CHAIRMAN BROWN: Okay. You all set up there?

You may proceed when you are ready.

EXAMINATION

BY MR. COX:

Q Mr. Enjamio, have you been sworn in for this hearing?

A Yes, I have.

Q Could you please state your name for the record?

A Sure. My name is Juan E. Enjamio.

Q Who is your current employer, and what is your business address?

A My employer is Florida Power & Light. My address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q What's your current position with FPL?

A I am Manager of Integrated Analysis.

Q And, Mr. Enjamio, did you cause to be filed on March 1st, 2017, seven pages of direct testimony in his proceeding?

A Yes, I did.

Q Did you also cause to be filed on October 16th, 2017, an errata correcting your March 1 testimony?

A Yes.

Q Do you have any other changes or corrections to your testimony today?

A No, I do not.

Q If I were to ask you the same questions today as contained in your testimony as corrected by the October 16th errata, would your answers be the

same?

A Yes, they would.

MR. COX: Chairman Brown, FPL requests that Mr. Enjamio's March 1st, 2017, direct testimony as corrected be inserted into the record as though read.

CHAIRMAN BROWN: We will go ahead and enter into the record Mr. Enjamio's prefiled testimony as corrected as though read.

MR. COX: Thank you.

(Whereupon, prefiled testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No: 20170001-EI Filed: October 16, 2017

ERRATA SHEET

MARCH 1, 2017 TESTIMONY OF JUAN E. ENJAMIO

PAGE #	LINE #	
Page 6	Line 18	Change “(14,600 barrels)” to “(15,300 barrels)”
Page 6	Line 18	Change “(3,600 tons)” to “(9,500 tons)”

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF JUAN E. ENJAMIO

DOCKET NO. 170001-EI

MARCH 1, 2017

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 Integrated Analysis in the Resource Assessment & Planning Department.

Q. Please describe your educational background and professional experience.

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

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

A. In my current position as Manager of Integrated Analysis, 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 Solar Energy Center Assumptions
- JE-2 Load Forecast
- JE-3 FPL Fuel Price Forecast
- JE-4 FPL Resource Plans
- JE-5 CPVRR – Costs and Benefits
- JE-6 Avoided Fossil Fuel
- JE-7 Avoided Air Emissions

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

A. The purpose of my testimony is to present the results of the economic analysis which shows that 596 megawatts alternating current ("MW_{ac}") of universal solar photovoltaic ("PV") generation scheduled to be placed in service in late 2017 and early 2018 are cost-effective. My testimony covers several areas. First, I identify the eight sites on which the solar PV facilities will be constructed. Second, I discuss the major assumptions and the methodology used to perform the economic analysis. Third, I present the results of the economic analysis demonstrating that the addition of 596 MW_{ac} of solar PV generation is cost-effective. Lastly, I discuss non-economic benefits that derive from the construction and operation of these facilities.

Q. Please summarize your testimony.

A. FPL is proposing the construction and operation of 596 MW_{ac} of solar PV generation, consisting of two separate construction projects, each comprising four universal solar energy centers with in-service dates of late 2017 and early 2018, respectively. FPL performed an economic analysis and determined that these centers result in a reduction in the Cumulative Present Value of Revenue Requirements ("CPVRR") to FPL customers, for a total savings of approximately $39 million. In addition, these centers are projected to result in a significant reduction in air emissions, primarily Carbon Dioxide ("CO_2"), and a reduction in the projected use of fossil fuels, thereby reducing FPL's reliance on generation fueled by natural gas.

Q. Please describe the proposed solar generation.

A. FPL is proposing to construct and operate 596 MW_{ac} of solar PV generation. Four centers with a total nameplate capacity of 298 MW_{ac} will be constructed and placed in service by December 31, 2017. Another four centers also with a total nameplate capacity of 298 MW_{ac} will be placed in-service by March 1, 2018. Each of these centers can generate about 176,000 MWh in a year. This is enough energy to serve about 15,000 homes. Exhibit JE-1 attached to my testimony describes the major characteristics of the eight centers. FPL witness Brannen describes each center in greater detail and demonstrates that the cost for the proposed solar generation falls well below the $1,750 per kilowatt alternating current ("kW_{ac}") threshold established in the FPL Rate Case Settlement approved by the Commission in Order No. PSC-16-0560-AS-EI.

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 official long-term load forecast, approved in December 2016. This updated load forecast, including system peaks and net energy for load, will be used in FPL's 2017 Ten Year Site Plan ("TYSP") and is shown in Exhibit JE-2;
- **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 in November 2016. This fuel forecast will be used in FPL's 2017 TYSP and is shown in Exhibit JE-3;
- **CO_2 Emission Price Forecast -** The CO_2 cost projections used in this filing are based on ICF's CO_2 emission price forecast dated December 2016. ICF is a consulting firm with extensive experience in forecasting the cost of air emissions and is recognized as one of the industry leaders in this field. This CO_2 emission price forecast will be used in FPL's 2017 TYSP.

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

A. For purposes of this filing, FPL developed two resource plans. The first resource plan, called the "No Solar Plan," does not include any new solar facilities beyond those already in-service as of the end of 2016. In this plan, future resource needs are met first by combined cycle units and short-term power purchases through the year 2030, and then by FPL's planned two new nuclear units, Turkey Point 6 and Turkey Point 7, which are assumed in these analysis to enter service in 2031 and 2032, respectively.

The second resource plan, called the "2017-2018 Solar Plan," adds the eight centers that, as I mentioned earlier, will be built in two separate construction projects, each comprising four sites. Since solar installations, existing and future, are assumed to provide FPL 54% of their nameplate capacity as firm capacity to meet the Company's reliability obligations, the in-service dates of the two combined cycle units required by 2030 were deferred, and the size of the combined cycle unit planned for 2033 was reduced to account for the solar firm capacity at time of summer peak. These two resource plans are shown in Exhibit JE-4.

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

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

The eight solar energy centers have an average summer firm capacity value of 54% of their nameplate rating. Therefore, each of the eight solar energy centers with a nameplate capacity of 74.5 MW_{ac} is assumed to have a firm capacity value of 40.2 MW_{ac} for a total firm capacity of 322 MW_{ac} at time of summer peak. Solar installations have little, if any, firm capacity value at time of winter peak due to FPL's winter peak occurring in the morning.

Q. Please provide an overview of the analytical process that FPL used to determine the cost-effectiveness of the proposed solar generation.

A. FPL used the hourly production costing model UPLAN to forecast the system economics and compare resource plans that include or exclude the 596 MW_{ac} of solar PV generation. This model has been used by FPL in prior proceedings at the Commission. Each UPLAN modeling run is used to determine generation system costs, consisting primarily of fuel costs, variable O&M costs, and emissions costs for a given resource plan. The output of each of the UPLAN model runs is then imported into FPL's Fixed Cost Spreadsheet ("FCSS") Model, which adds fixed costs such as capital costs, capital replacements costs, and fixed O&M costs. The FCSS Model is used to determine the CPVRR for each resource plan.

Q. Please provide the result of the economic analysis.

A. To determine the CPVRR impact of the proposed solar generation, FPL subtracted the CPVRR of the No Solar Plan from the CPVRR of the 2017-2018 Solar Plan. As shown in Exhibit JE-5, CPVRR Costs and Benefits, the CPVRR benefit to FPL customers is approximately $39 million.

Q. Will these solar energy centers reduce FPL's use of fossil fuels, specifically natural gas and oil?

A. Yes. The energy from these solar energy centers will displace fossil fuel generation. Combined, these centers are expected to reduce the annual average use of natural gas by 8,400 million cubic feet, the use of oil by 14,600 barrels, and the use of coal by 3,600 tons. By adding these solar energy centers to its generation fleet, FPL reduces its reliance on natural gas, as well as coal and oil.

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 results in an average annual reduction of 526,000 tons of global warming gases, specifically CO_2. This reduction in CO_2 is equivalent to removing approximately 102,000 cars from the road. Sulfur dioxide and nitrogen oxide emissions are reduced by an annual average of 46 tons and 64 tons, respectively.

Q. What is your conclusion regarding the cost effectiveness of the proposed solar generation?

A. As demonstrated by the economic analysis described in my testimony, the addition of these solar energy centers will result in CPVRR savings of approximately $39 million. In addition, these centers will reduce the use of fossil fuels, reduce air emissions, and reduce FPL's reliance on natural gas. Therefore, I conclude that the proposed solar generation meets the cost-effectiveness requirement established in the FPL Rate Case Settlement and recommend approval by the Commission.

Q. Does this conclude your testimony?

A. Yes.

BY MR. COX:
Q Mr. Enjamio, did you also have Exhibits JE-1 through JE-7 attached to your testimony?
A Yes, I do.
Q Did you cause to be filed a correction could your JE-6 on June 14th, 2017?
A Yes, I did.
Q Do you have any other corrections or changes to your exhibits JE-6 through JE-7?
A No.
MR. COX: Chairman Brown, these exhibits, as corrected have been identified as Exhibits 28 through 34 on the staff comprehensive list.
CHAIRMAN BROWN: So noted.
BY MR. COX:
Q Mr. Enjamio, did you -- did you also cause to be filed August 2nd, 2017, three pages of testimony supplementing your direct testimony in this proceeding?
A Yes, I did.
Q Do you have any changes or corrections to that testimony?
A No.
Q If I were to ask you the same questions today as contained in that testimony, would your

answers be the same?

A Yes, they would.

MR. COX: Chairman Brown, FPL would request that Mr. Enjamio's August 2nd testimony be inserted into the record as though read.

CHAIRMAN BROWN: Go ahead and enter Mr. Enjamio's prefiled August 2nd testimony into the record as though read.

MR. COX: Okay.

(Whereupon, prefiled testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF JUAN E. ENJAMIO

DOCKET NO. 20170001-EI

AUGUST 2, 2017

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 Integrated Analysis in the Resource Assessment & Planning Department.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes, I submitted direct testimony in this proceeding on March 1, 2017, which included Exhibits JE-1 through JE-7.

Q. Are you sponsoring any additional exhibit in this case?

A. Yes. I am sponsoring the following additional exhibits, which are attached to this testimony:

- JE-8 - Updated Project Assumptions
- JE-9 - Updated CPVRR – Costs and Benefits

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present an updated economic analysis which shows that the 596 megawatts alternating current ("MW_{ac}") of universal solar photovoltaic

("PV") generation scheduled to be placed in service in late 2017 and early 2018 remain cost-effective. My testimony identifies the updated cost assumptions used in the economic analysis and presents the updated results.

Q. Please explain why you are providing an updated economic analysis.

A. I am providing an update because, since the time of my March 1 testimony, there has been a significant change in Florida law that has resulted in a substantial change in the cost assumptions underlying FPL's economic evaluation. Specifically, during the 2017 legislative session, the Florida Legislature enacted Senate Bill 90, which provides an 80% exemption from property taxes for qualifying solar installations, for a twenty-year period. This exemption, which did not exist at the time of the March 1 filing, applies to three of the four sites planned for 2018: Blue Cypress, Barefoot Bay and Loggerhead.

Q. What is the cost reduction resulting from the property tax exemption?

A. The property tax reduction for all three qualifying sites is $34 million on a cumulative present value of revenue requirements ("CPVRR") basis.

Q. Does your updated economic analysis reflect any other cost changes?

A. Yes. Witness Brannen describes a $31 million reduction in construction costs since the time of the March 1 filing which results in a $33 million reduction in CPVRR. That reduction is also included in the updated economic analysis. Exhibit JE-8 reflects the updated cost, inclusive of reduced property taxes and construction costs.

Q. Does your updated economic analysis reflect any other changes?

A. No, the updated economic analysis otherwise reflects the same system assumptions used in the March 1 filing.

Q. In developing the updated economic analysis, did you employ the same analytical process to determine the cost-effectiveness of the proposed solar generation?

A. Yes, the updated economic analysis used the same resource plans that formed the basis for the March 1 cost-effectiveness analysis, and FPL again employed the UPLAN hourly production costing model and the Fixed Cost Spreadsheet Model to determine the CPVRR for each resource plan.

Q. Please provide the result of the economic analysis.

A. To determine the updated CPVRR impact of the proposed solar generation, FPL subtracted the CPVRR of the No Solar Plan from the CPVRR of the 2017-2018 Solar Plan using the updated cost information. As shown in Exhibit JE-9, Updated CPVRR Costs and Benefits, the 2017-2018 Solar Plan is projected to save FPL customers approximately $106 million (CPVRR) compared to the No Solar Plan.

Q. Does this change your conclusion regarding the cost effectiveness of the proposed solar generation?

A. No, the updated economic analysis strengthens my original conclusion that the 2017 and 2018 Projects are cost effective. The addition of the 2017 and 2018 Projects is now projected to result in $106 million (CPVRR) of customer savings.

Q. Does this conclude your testimony?

A. Yes.

BY MR. COX:

Q Mr. Enjamio, did you also have Exhibits JE-8 A d JE-9 attached to your testimony August 2nd?

A Yes, I did.

MR. COX: Chairman Brown, these exhibits have been identified as Exhibits 35 and 36 on the staff comprehensive exhibit list.

CHAIRMAN BROWN: So noted. Thank you.

MR. COX: Thank you.

BY MR. COX:

Q Mr. Enjamio, have you prepared a summary of your March 1st and August 2nd testimony?

A Yes, I have.

Q Could you please present your summary to the Commission at this time?

A Yes.

Good afternoon, Chairman Brown and Commissioners. My March testimony describes the major assumptions and the methodology used in FPL's economic analysis of its proposed 2017 and 2018 solar projects, and presents the results of this analysis. My other testimony presents the results of an undated economic analysis based on updated assumptions.

FPL is proposing the construction and

operation of 596 megawatts of solar generation consisting of two separated projects. Each of the two projects is comprised as four universal solar energy centers, each rated at 74.5 megawatts. FPL estimates that all four of the solar energy centers in the 2017 project will be placed in service by December 31st, 2017; and all four centers in the 2018 project will be placed in service by March 1st, 2018.

In my March testimony, I present the results of FPL's economic analysis which shows that these two projects will result in a reduction in the cumulative present value of revenue requirements to FPL customers for a total savings of approximately $39 million.

After my March testimony was filed, two factors were identified that would impact the results of this analysis. The first factor was that the Florida legislation passage of Senate Bill 90, which provides an exception to qualifying solar projects. Three of the four sites in the 2018 project qualify for this exemption.

The second factor was a reduction in the expected capital costs of the projects of approximately $31 million. FPL updated its analysis to include the impact of these two factors, and I present that updated analysis in my August testimony.

The updated analysis shows that these projects will result in a reduction in cumulative present value of revenue requirements to our customers for a total savings of approximately $106 million.

In addition to the economic benefits to our customers, FPL's solar projects are projected to result in a significant reduction in air emissions, and also result in a reduction in the projected use of fossil fuels; thereby, reducing FPL's reliance on generation of fuel by natural gas. Because the capital cost of these projects is significantly below the capital cost threshold, and because they meet the cost-effectiveness established in the FPL rate case settlement, I recommend their approval by the Commission.

Thank you.

CHAIRMAN BROWN: Mr. Cox, are you ready to tender him for cross?

MR. COX: Yes. Mr. Enjamio is tendered for cross-examination.

CHAIRMAN BROWN: All right. Thank you.

Office of Public Counsel.

MR. SAYLER: Madam Chair, we have no questions, and counsel for FRF, who is not here, has no questions as well.

CHAIRMAN BROWN: That's what I thought.

All right, FIPUG, Mr. Moyle.

MR. MOYLE: Thank you. I do have a number of exhibits, and I think maybe if we take a few minutes and, you know, and pass them out and mark them now, some of them I -- I will use with this witness, some of them I may not, but I am okay on just doing it all now --

CHAIRMAN BROWN: Okay.

MR. MOYLE: -- as I think that's your preference --

CHAIRMAN BROWN: Let's do it.

MR. MOYLE: -- instead of doing it one at a time, is that right?

CHAIRMAN BROWN: Thank you.

Why don't we take a couple minute break.

Let's take a three-minute break, folks can stretch their legs and we'll get back on the record after that.

(Brief recess.)

(Transcript continues in sequence in

Volume 3.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

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

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

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

DATED this 2nd day of November, 2017.

Debbie R Krick

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