Gulf Power

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March 1, 2017

Ms. Carlotta Stauffer, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

RE: Docket No. 170001-EI

Dear Ms. Stauffer:

Attached is Gulf Power Company's Fuel and Purchased Power Cost Recovery Clause Final True-Up Testimony and Exhibits of C. Shane Boyett to be filed in the above-referenced docket.

Pursuant to the Order Establishing Procedure in this docket, electronic copies of exhibits CSB-1, CSB-2 and CSB-3 will be provided to the parties under separate cover.

Sincerely,

Robert L. McGee, Jr.

Robert L. McGee, Jr.
Regulatory and Pricing Manager

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Attachments

cc: Beggs & Lane
Jeffrey A. Stone, Esq.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FUEL COST AND PURCHASED POWER COST RECOVERY CLAUSE

Docket No. 170001-EI

Prepared Direct Testimony & Exhibits of C. Shane Boyett

ACTUAL TRUE-UP FOR THE PERIOD:
JANUARY – DECEMBER 2016 (Fuel)
JANUARY – DECEMBER 2016 (Capacity)

Date of Filing: March 1, 2017

Gulf Power

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.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 170001-EI

Before me, the undersigned authority, personally appeared C. Shane Boyett, who being first duly sworn, deposes and says that he is the Supervisor of Regulatory and Cost Recovery of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

C. Shane Boyett

C. Shane Boyett
Supervisor of Regulatory and Cost Recovery

Sworn to and subscribed before me this 28th day of February, 2017.

Melissa Darnes

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA
MELISSA DARNES
MY COMMISSION # FF 912698
EXPIRES: December 17, 2019
Bonded Thru Budget Notary Services

Schedule 1

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2016 - DECEMBER 2016

1. Estimated over/(under)-recovery for the period January 2016 - December 2016 (Schedule E-1B, Line 6 + 7 + 8, filed August 4, 2015) approved in FPSC Order No. PSC-16-0547-FOF-EI issued on December 5, 2016)	$ 27,383,731
2. Actual over/(under)-recovery for the period January 2016 - December 2016 (December 2015 Schedule A-2, page 2 of 3, "Period-to-Date", Lines 7 + 8 + 12, included in Exhibit CSB-2)	16,586,321
3. Amount to be refunded/(recovered) in the January 2018 - December 2018 projection period (Line 2 - Line 1)	$ (10,797,411)

Schedule CCA-1

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2016 - DECEMBER 2016

1. Estimated over/(under)-recovery for the period January 2016 - December 2016 (Schedule CCE-1a, line 1, filed August 4, 2016 and approved in FPSC Order No. PSC-16-0547-FOF-EI issued on December 5, 2016)	$	149,231
2. Actual over/(under)-recovery for the period January 2016 - December 2016 (Schedule CCA-2, Line 10 + 11 + 14)		695,190
3. Amount to be refunded/(recovered) in the January 2018 - December 2018 projection period (Line 2 - Line 1)	$	545,959

Schedule CCA-2

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2016 - DECEMBER 2016

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1. IIC Payments / (Receipts) ($)		(31,479)	(13,056)	(38,017)	16,919	(9,402)	(14,270)	(14,681)	(13,859)	(14,270)	(17,260)	(14,918)	(40,190)	(204,483)
2. Other Capacity Payments / (Receipts)		7,386,547	7,386,547	7,386,547	7,385,880	7,435,880	7,402,529	7,217,678	7,217,678	7,217,678	7,217,678	7,158,752	7,276,605	87,689,999
3. Transmission Revenue ($)		(10,822)	(10,717)	(11,030)	(11,835)	(10,032)	(16,929)	(39,266)	(21,905)	(17,711)	(15,371)	(12,191)	(11,721)	(189,530)
4. Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)		7,344,246	7,362,774	7,337,500	7,390,964	7,416,446	7,371,330	7,163,731	7,181,914	7,185,697	7,185,047	7,131,643	7,224,694	87,295,986
5. Jurisdictional %		0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	
6. Total Jurisdictional Recovery Amount (Line 4 * 5) ($)		7,129,167	7,147,152	7,122,618	7,174,517	7,199,252	7,155,458	6,953,938	6,971,589	6,975,261	6,974,630	6,922,790	7,013,116	84,739,488
7. Jurisdictional Capacity Cost Recovery Revenues Net of Taxes ($)		6,998,240	5,856,599	5,732,927	5,693,165	7,353,175	8,609,179	9,723,262	9,084,505	8,245,592	6,761,165	5,501,071	5,862,528	85,421,408
8. True-Up Provision ($)		1,491	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	17,859
9. Jurisdictional Capacity Cost Recovery Revenue (Line 7 + 8) ($)		6,999,731	5,858,087	5,734,415	5,694,653	7,354,663	8,610,667	9,724,750	9,085,993	8,247,080	6,762,653	5,502,559	5,864,016	85,439,267
10. Over/(Under) Recovery (Line 9 - 6) ($)		(129,436)	(1,289,065)	(1,388,203)	(1,479,864)	155,411	1,455,209	2,770,812	2,114,404	1,271,819	(211,977)	(1,420,231)	(1,149,100)	699,779
11. Interest Provision ($)		(337)	(590)	(1,097)	(1,463)	(1,509)	(1,344)	(762)	65	697	963	636	152	(4,589)
12. Beginning Balance True-Up & Interest Provision ($)		(947,908)	(1,079,172)	(2,370,315)	(3,761,103)	(5,243,918)	(5,091,504)	(3,639,127)	(870,565)	1,242,416	2,513,444	2,300,942	879,859	(947,908)
13. True-Up Collected/(Refunded) ($)		(1,491)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(17,859)
14. Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-
15. End of Period Total Net True-Up (Lines 10 + 11 + 12 + 13 + 14) ($)		(1,079,172)	(2,370,315)	(3,761,103)	(5,243,918)	(5,091,504)	(3,639,127)	(870,565)	1,242,416	2,513,444	2,300,942	879,859	(270,577)	(270,577)
Average Monthly Interest Rate		0.0333%	0.0342%	0.0358%	0.0325%	0.0292%	0.0308%	0.0338%	0.0350%	0.0371%	0.0400%	0.0400%	0.0500%	
Commercial Paper Annual Rate	0.40%	0.40%	0.42%	0.44%	0.34%	0.36%	0.38%	0.43%	0.41%	0.48%	0.48%	0.48%	0.72%	
Average Annual Rate		0.400%	0.410%	0.430%	0.390%	0.350%	0.370%	0.405%	0.420%	0.445%	0.480%	0.480%	0.600%	

Schedule CCA-3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2016 - DECEMBER 2016

	January	February	March	April	May	June	July	August	September	October	November	December	Total
1. Beginning True-Up Amount ($)	(947,908)	(1,079,172)	(2,370,315)	(3,761,103)	(5,243,918)	(5,091,504)	(3,639,127)	(870,565)	1,242,416	2,513,444	2,300,942	879,859	
2. Ending True-Up Amount Before Interest ($)	(1,078,835)	(2,369,725)	(3,760,006)	(5,242,455)	(5,089,995)	(3,637,783)	(869,803)	1,242,351	2,512,747	2,299,979	879,223	(270,729)	
3. Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	(2,026,743)	(3,448,897)	(6,130,321)	(9,003,558)	(10,333,913)	(8,729,287)	(4,508,930)	371,786	3,755,163	4,813,423	3,180,165	609,130	
4. Average True-Up Amount ($)	(1,013,372)	(1,724,449)	(3,065,161)	(4,501,779)	(5,166,957)	(4,364,644)	(2,254,465)	185,893	1,877,582	2,406,712	1,590,083	304,565	
5. Interest Rate - First Day of Reporting Business Month	0.40%	0.40%	0.42%	0.44%	0.34%	0.36%	0.38%	0.43%	0.41%	0.48%	0.48%	0.48%	
6. Interest Rate - First Day of Subsequent Business Month	0.40%	0.42%	0.44%	0.34%	0.36%	0.38%	0.43%	0.41%	0.48%	0.48%	0.48%	0.72%	
7. Total Interest Rate (Lines 5 + 6)	0.80%	0.82%	0.86%	0.78%	0.70%	0.74%	0.81%	0.84%	0.89%	0.96%	0.96%	1.20%	
8. Average Interest Rate	0.400%	0.410%	0.430%	0.390%	0.350%	0.370%	0.405%	0.420%	0.445%	0.480%	0.480%	0.600%	
9. Monthly Average Interest Rate (1/12 of Line 8)	0.0333%	0.0342%	0.0358%	0.0325%	0.0292%	0.0308%	0.0338%	0.0350%	0.0371%	0.0400%	0.0400%	0.0500%	
10. Interest Provision For the Month (Lines 4 X 9) ($)	(337)	(590)	(1,097)	(1,463)	(1,509)	(1,344)	(762)	65	697	963	636	152	(4,589)

Schedule CCA-4

Gulf Power Company
2016 Capacity Contracts

		A	B	C	D
		Term			Contract
2	**Contract/Counterparty**	**Start**	**End [1]**		**Type**
3	**Southern Intercompany Interchange**	5/1/2007	5 Yr Notice		SES Opco
4	***PPAs***				
5	**Shell Energy N.A. (U.S.), LP**	11/2/2009	5/31/2023		Firm
6	***Other***				
7	**Duke Energy**	7/26/2016	7/27/2016		Other
8	**Cargill Power, LLC**	2/13/2016	2/14/2016		Other
9	**South Carolina PSA**	9/1/2003	12/31/2016		Other
10	**South Carolina Electric & Gas**	1/2/2016	12/31/2016		Other
11	**The Energy Authority**	1/5/2016	1/5/2016		Other

		A	B	C	D	E	F	G	H	I	J	K	L	M
12	**Capacity Costs ($)**	**January [2]**	**February [3]**	**March**	**April**	**May [3]**	**June**	**July**	**August**	**September**	**October**	**November [2]**	**December [2]**	**Total**
13	Southern Intercompany Interchange	(17,016)	1,445	(23,747)	31,189	4,868	0	0	0	0	(2,990)	(648)	(25,920)	(32,819)
14	*PPAs*													
15	Shell Energy N.A. (U.S.), LP	[redacted]												
16														
17	*Other*													
18	Duke Energy	0	0	0	0	0	0	[redacted]	[redacted]	0	0	0	0	0
19	Cargill Power, LLC	0	[redacted]	0	0	0	0	0	0	0	0	0	0	[redacted]
20	South Carolina PSA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(38,496)
21	South Carolina Electric & Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(132,744)
22	The Energy Authority	[redacted]	0	0	0	0	0	0	0	0	0	0	0	[redacted]
23	Total	7,355,068	7,373,491	7,348,530	7,402,799	7,426,478	7,388,259	7,202,997	7,203,819	7,203,408	7,200,418	7,143,834	7,177,488	87,426,589

		January	February	March	April	May	June	July	August	September	October	November	December [2]
24	**Capacity MW**												
25	Southern Intercompany Interchange	(23.1)	0.0	(72.7)	157.0	0.0	0.0	0.0	0.0	0.0	(18.3)	(0.8)	(158.8)
26	*PPAs*												
27	Shell Energy N.A. (U.S.), LP	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0
28													
29	*Other*												
30	Duke Energy	0.0	0.0	0.0	0.0	0.0	0.0	[redacted]	[redacted]	0.0	0.0	0.0	0.0
31	Cargill Power, LLC	0.0	[redacted]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	South Carolina PSA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
33	South Carolina Electric & Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
34	The Energy Authority	[redacted]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Southern Intercompany Interchange reserve sharing charge includes prior month true up
(3) Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 170001-EI

MONTHLY FUEL FILING

December 2016

GULF POWER
A SOUTHERN COMPANY

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: DECEMBER 2016

LINE	DESCRIPTION	REFERENCE		AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$	20,345,925
2	Fuel Related Transactions		$	-
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	$	1,273
4	Hedging Settlement Costs	Schedule A-2, Line A-5	$	1,750,470
5	Fuel Cost of Purchased Power	Schedule A-7	$	-
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	$	17,695,006
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	$	-
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	$	704,975
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	$	(9,868,067)
10	Total Fuel and Net Power Transactions		$	30,629,583

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2016

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	20,345,925	15,164,331	5,181,594	34.17	626,526,000	537,513,000	89,013,000	16 56	3 2474	2.8212	0.43	15.11
2	Hedging Settlement Costs (A2)	1,750,470	2,287,103	(536,633)	(23.46)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	1,273	0	1,273	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	22,097,668	17,451,434	4,646,234	26.62	626,526,000	537,513,000	89,013,000	16 56	3 5270	3.2467	0.28	8.63
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	17,695,006	14,046,000	3,649,006	25 98	673,756,317	484,618,000	189,138,317	39.03	2.6263	2.8984	(0.27)	(9.39)
9	Energy Cost of Schedule E Economy Purch. (A9)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facili ies (A8)	704,975	355,000	349,975	98 58	24,691,504	13,731,000	10,960,504	79 82	2 8551	2.5854	0.27	10.43
12	TOTAL COST OF PURCHASED POWER	18,399,981	14,401,000	3,998,981	27.77	698,447,821	498,349,000	200,098,821	40.15	2.6344	2.8897	(0.26)	(8.83)
13	Total Available MWH (Line 5 + Line 12)	40,497,649	31,852,434	8,645,215	27.14	1,324,973,821	1,035,862,000	289,111,821	27 91				
14	Fuel Cost of Economy Sales (A6)	(446,089)	(234,000)	(212,089)	90.64	(17,307,859)	(10,994,000)	(6,313,859)	57.43	(2 5774)	(2.1284)	(0.45)	(21.10)
15	Gain on Economy Sales (A6)	(77,543)	(47,000)	(30,543)	64 99	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(9,344,435)	(2,634,000)	(6,710,435)	254.76	(464,489,169)	(123,675,000)	(340,814,169)	275 57	(2.0118)	(2.1298)	0.12	5.54
	TOTAL FUEL COSTS & GAINS OF POWER SALES												
17	(LINES 14 + 15 + 16)	(9,868,067)	(2,915,000)	(6,953,067)	238 53	(481,797,028)	(134,669,000)	(347,128,028)	257.76	(2.0482)	(2.1646)	0.12	5.38
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
	TOTAL FUEL & NET POWER TRANSACTIONS												
19	(LINES 5 + 12 + 17)	30,629,583	28,937,434	1,692,149	5 85	843,176,793	901,193,000	(58,016,207)	(6.44)	3.6326	3.2110	0.42	13.13
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	45,863	56,931	(11,068)	(19.44)	1,262,549	1,773,000	(510,451)	(28.79)	3.6326	3.2110	0.42	13.13
22	T & D Losses *	1,700,294	1,454,455	245,839	16 90	46,806,523	45,296,000	1,510,523	3 33	3.6326	3.2110	0.42	13.13
23	TERRITORIAL KWH SALES	30,629,583	28,937,434	1,692,149	5 85	795,107,721	854,124,000	(59,016,279)	(6 91)	3 8523	3.3880	0.46	13.70
24	Wholesale KWH Sales	927,923	952,041	(24,118)	(2 53)	24,087,902	28,101,000	(4,013,098)	(14 28)	3 8522	3.3879	0.46	13.70
25	Jurisdictional KWH Sales	29,701,660	27,985,393	1,716,267	6.13	771,019,819	826,023,000	(55,003,181)	(6.66)	3 8523	3.3880	0.46	13.70
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	29,746,212	28,027,371	1,718,841	6.13	771,019,819	826,023,000	(55,003,181)	(6.66)	3 8580	3.3930	0.47	13.70
28	TRUE-UP	(1,614,174)	(1,614,174)	0	0.00	771,019,819	826,023,000	(55,003,181)	(6.66)	(0 2094)	(0.1954)	(0.01)	7.16
29	TOTAL JURISDICTIONAL FUEL COST	28,132,038	26,413,197	1,718,841	6 51	771,019,819	826,023,000	(55,003,181)	(6.66)	3.6486	3.1976	0.45	14.10
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.6512	3.1999	0.45	14.10
32	GPIF Reward / (Penalty)	220,693	220,693	0	0.00	771,019,819	826,023,000	(55,003,181)	(6.66)	0.0286	0.0267	0.00	7.12
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.6798	3.2266	0.45	14.05
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.680	3 227		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2016
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	234,983,070	255,692,351	(20,709,281)	(8.10)	7,263,317,000	7,643,508,000	(380,191,000)	(4 97)	3 2352	3.3452	(0.11)	(3.29)
2	Hedging Settlement Costs (A2)	54,060,780	21,046,602	33,014,178	156 86	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	13,114	0	13,114	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	289,056,964	276,738,953	12,318,011	4.45	7,263,317,000	7,643,508,000	(380,191,000)	(4 97)	3 9797	3.6206	0.36	9.92
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0.00	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	187,389,167	202,884,000	(15,494,833)	(7.64)	9,845,070,080	6,962,859,000	2,882,211,080	41 39	1 9034	2.9138	(1.01)	(34.68)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facili ies (A8)	6,187,432	5,026,000	1,161,432	23.11	227,624,504	182,598,000	45,026,504	24.66	2.7183	2.7525	(0.03)	(1.24)
12	TOTAL COST OF PURCHASED POWER	193,576,598	207,910,000	(14,333,402)	(6 89)	10,072,694,584	7,145,457,000	2,927,237,584	40 97	1 9218	2.9097	(0.99)	(33.95)
13	Total Available MWH (Line 5 + Line 12)	482,633,563	484,648,953	(2,015,390)	(0.42)	17,336,011,584	14,788,965,000	2,547,046,584	17 22				
14	Fuel Cost of Economy Sales (A6)	(3,033,743)	(2,668,000)	(365,743)	13.71	(129,359,388)	(118,508,000)	(10,851,388)	9.16	(2 3452)	(2.2513)	(0.09)	(4.17)
15	Gain on Economy Sales (A6)	(524,921)	(552,000)	27,079	(4 91)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(64,089,314)	(65,332,000)	1,242,686	(1 90)	(5,191,964,903)	(2,774,329,000)	(2,417,635,903)	87.14	(1 2344)	(2.3549)	1.12	47.58
	TOTAL FUEL COSTS & GAINS OF POWER SALES												
17	(LINES 14 + 15 + 16)	(67,647,977)	(68,552,000)	904,022	(1 32)	(5,321,324,291)	(2,892,837,000)	(2,428,487,291)	83 95	(1 2713)	(2.3697)	1.10	46.35
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
	TOTAL FUEL & NET POWER TRANSACTIONS												
19	(LINES 5 + 12 + 17)	414,985,585	416,096,953	(1,111,368)	(0 27)	12,014,687,293	11,896,128,000	118,559,293	1.00	3.4540	3.4978	(0.04)	(1.25)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	524,451	726,773	(202,322)	(27 84)	15,183,880	20,778,000	(5,594,120)	(26 92)	3.4540	3.4978	(0.04)	(1.25)
22	T & D Losses *	20,807,455	20,381,261	426,194	2.09	602,416,171	582,688,000	19,728,171	3 39	3.4540	3.4978	(0.04)	(1.25)
23	TERRITORIAL KWH SALES	414,985,586	416,096,953	(1,111,367)	(0 27)	11,397,087,242	11,292,662,000	104,425,242	0 92	3.6412	3.6847	(0.04)	(1.18)
24	Wholesale KWH Sales	11,490,123	12,201,714	(711,591)	(5 83)	315,581,966	330,925,000	(15,343,034)	(4.64)	3.6409	3.6872	(0.05)	(1.26)
25	Jurisdictional KWH Sales	403,495,463	403,895,239	(399,776)	(0.10)	11,081,505,276	10,961,737,000	119,768,276	1.09	3.6412	3.6846	(0.04)	(1.18)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	404,100,707	404,501,081	(400,374)	(0.10)	11,081,505,276	10,961,737,000	119,768,276	1.09	3.6466	3.6901	(0.04)	(1.18)
28	TRUE-UP	(19,370,087)	(19,370,087)	0	0.00	11,081,505,276	10,961,737,000	119,768,276	1.09	(0.1748)	(0.1767)	0.00	(1.08)
29	TOTAL JURISDICTIONAL FUEL COST	384,730,620	385,130,994	(400,374)	(0.10)	11,081,505,276	10,961,737,000	119,768,276	1.09	3.4718	3.5134	(0.04)	(1.18)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.4743	3.5159	(0.04)	(1.18)
32	GPIF Reward / (Penalty)	2,648,312	2,648,312	0	0.00	11,081,505,276	10,961,737,000	119,768,276	1.09	0.0239	0.0242	(0.00)	(1.24)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.4982	3.5401	(0.04)	(1.18)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.498	3 540		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2016

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	20,168,147.33	14,987,697	5,180,450.33	34.56	232,906,885.96	253,010,293	(20,103,407.04)	(7.95)
1a	Other Generation	177,777.36	176,634	1,143.36	0.65	2,076,183.59	2,682,058	(605,874.41)	(22.59)
2	Fuel Cost of Power Sold	(9,868,066.88)	(2,915,000)	(6,953,066.88)	(238.53)	(67,647,977.33)	(68,552,000)	904,022.67	1.32
3	Fuel Cost - Purchased Power	17,695,006.50	14,046,000	3,649,006.50	25.98	187,389,167.06	202,884,000	(15,494,832.94)	(7.64)
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	704,975.34	355,000	349,975.34	98.58	6,187,431.77	5,026,000	1,161,431.77	23.11
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	1,750,470.00	2,287,103	(536,633.00)	(23.46)	54,060,780.00	21,046,602	33,014,178.00	156.86
6	Total Fuel & Net Power Transactions	30,628,309.65	28,937,434	1,690,875.65	5.84	414,972,471.05	416,096,953	(1,124,481.95)	(0.27)
7	AdjustmentsTo Fuel Cost*	1,273.28	0	1,273.28	100.00	13,114.48	0	13,114.48	100.00
8	Adj. Total Fuel & Net Power Transactions	30,629,582.93	28,937,434	1,692,148.93	5.85	414,985,585.53	416,096,953	(1,111,367.47)	(0.27)
B.	*KWH Sales*								
1	Jurisdictional Sales	771,019,819	826,023,000	(55,003,181)	(6.66)	11,081,505,276	10,961,737,000	119,768,276	1.09
2	Non-Jurisdictional Sales	24,087,902	28,101,000	(4,013,098)	(14.28)	315,581,966	330,925,000	(15,343,034)	(4.64)
3	Total Territorial Sales	795,107,721	854,124,000	(59,016,279)	(6.91)	11,397,087,242	11,292,662,000	104,425,242	0.92
4	Juris. Sales as % of Total Terr. Sales	96.9705	96.7100	0.2605	0.27	97.2310	97.0696	0.1614	0.17

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2016

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	26,088,715.42	30,125,671	(4,036,955.53)	(13.40)	404,136,512.90	399,782,672	4,353,841.22	1.09
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	1,614,174.00	1,614,174	0.00	0.00	19,370,087.00	19,370,087	0.00	0.00
2b	Incentive Provision	(220,534.00)	(220,534)	0.00	0.00	(2,646,407.00)	(2,646,407)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	27,482,355.42	31,519,311	(4,036,955.58)	(12.81)	420,860,192.90	416,506,352	4,353,840.90	1.05
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	30,629,582.93	28,937,434	1,692,148.93	5.85	414,985,584.76	416,096,953	(1,111,368.24)	(0.27)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.9705	96.7100	0.2605	0.27	97.2310	97.0696	0.1614	0.17
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	29,746,212.20	28,027,371	1,718,841.20	6.13	404,100,706.82	404,501,081	(400,374.18)	(0.10)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(2,263,856.78)	3,491,940	(5,755,796.78)	164.83	16,759,486.08	12,005,272	4,754,214.08	(39.60)
8	Interest Provision for the Month	8,685.23	5,552	3,133.23	(56.43)	80,520.86	43,379	37,141.86	(85.62)
9	Beginning True-Up & Interest Provision	19,309,482.87	10,165,333	9,144,149.87	(89.95)	18,046,021.07	19,370,087	(1,324,065.93)	6.84
10	True-Up Collected / (Refunded)	(1,614,174.00)	(1,614,174)	0.00	0.00	(19,370,087.00)	(19,370,087)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	15,440,137.32	12,048,651	3,391,486.32	(28.15)	15,515,941.01	12,048,651	3,467,290.01	(28.78)
12	Adjustment [1]	(177,882.72)	(866,563.19)	688,680.47	(79.47)	(253,686.41)	(866,563)	612,876.78	(70.72)
13	End of Period - Total Net True-Up	15,262,254.60	11,182,088	4,080,166.79	(36.49)	15,262,254.60	11,182,088	4,080,166.79	(36.49)

Adjustment for Scherer Unit 3 to retail
(177,882.72)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2016

		CURRENT MONTH $ ACTUAL	ESTIMATED	DIFFERENCE AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	19,309,482.87	10,165,333	9,144,149.87	89.95
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	15,431,452.09	12,043,099	3,388,353.09	28.14
3	Total of Beginning & Ending True-Up Amts.	34,740,934.96	22,208,432	12,532,502.96	56.43
4	Average True-Up Amount	17,370,467.48	11,104,216	6,266,251.48	56.43
	Interest Rate				
5	1st Day of Reporting Business Month	0.48	0.48	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.72	0.72	0.0000	
7	Total (D5+D6)	1.20	1.20	0.0000	
8	Annual Average Interest Rate	0.60	0.60	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0500	0.0500	0.0000	
10	Interest Provision (D4*D9)	8,685.23	5,552	3,133.23	56.43
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2016

SCHEDULE A-3

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	101,890	61,381	40,509	66.00	1,173,203	716,548	456,655	63.73
2	COAL	8,844,454	4,836,188	4,008,266	82.88	141,951,325	139,256,471	2,694,854	1.94
3	GAS	10,759,187	9,863,545	895,642	9.08	87,768,653	111,201,991	(23,433,338)	(21.07)
4	GAS (B.L.)	567,325	337,424	229,901	68.13	3,219,642	3,749,825	(530,183)	(14.14)
5	LANDFILL GAS	73,069	65,793	7,276	11.06	772,945	767,516	5,429	0.71
6	OIL - C.T.	-	0	0	0.00	97,302	0	97,302	100.00
7	TOTAL ($)	20,345,925	15,164,331	5,181,594	34.17	234,983,070	255,692,351	(20,709,281)	(8.10)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	252,452	156,963	95,489	60.84	3,701,231	4,033,496	(332,265)	(8.24)
10	GAS	371,896	378,450	(6,554)	(1.73)	3,537,563	3,585,223	(47,660)	(1.33)
11	LANDFILL GAS	2,184	2,100	84	4.00	24,158	24,789	(631)	(2.55)
12	OIL - C.T.	(6)	0	(6)	100.00	365	0	365	100.00
13	TOTAL (MWH)	626,526	537,513	89,013	16.56	7,263,317	7,643,508	(380,191)	(4.97)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	1,619	944.00	675	71.50	18,569	9,498	9,071	95.51
15	COAL (TONS)	134,496	42,854	91,642	213.85	1,909,330	1,679,296	230,034	13.70
16	GAS (MCF) (1)	2,595,498	2,578,347	17,151	0.67	24,998,837	24,113,347	885,490	3.67
17	OIL - C.T. (BBL)	0	0	0	0.00	1,219	0	1,219	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	3,001,036	1,735,344	1,265,692	72.94	42,245,851	43,526,598	(1,280,747)	(2.94)
19	GAS - Generation (1)	2,581,493	2,629,914	(48,421)	(1.84)	25,281,832	24,495,615	786,217	3.21
20	OIL - C.T.	0	0	0	0.00	7,093	0	7,093	100.00
21	TOTAL (MMBTU)	5,582,529	4,365,258	1,217,271	27.89	67,534,776	68,022,213	(487,437)	(0.72)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00
23	COAL	40.29	29.20	11.09	37.98	50.96	52.77	(1.81)	(3.43)
24	GAS	59.36	70.41	(11.05)	(15.69)	48.70	46.91	1.79	3.82
25	LANDFILL GAS	0.35	0.39	(0.04)	(10.26)	0.33	0.32	0 01	3.13
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.01	0.00	0 01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0 00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	62.93	65.02	(2.09)	(3.21)	63.18	75.44	(12 26)	(16.25)
29	COAL ($/TON)	65.76	64.26	1.50	2.33	74.35	75.01	(0.66)	(0.88)
30	GAS ($/MCF) (1)	4.30	3.89	0.41	10.54	3.56	4.66	(1.10)	(23.61)
31	OIL - C.T. ($/BBL)	0.00	0.00	0.00	0.00	79.82	0.00	79 82	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	3.17	3.02	0.15	4.97	3.46	3.30	0.16	4.85
33	GAS - Generation (1)	4.10	3.68	0.42	11.41	3.39	4.43	(1.04)	(23.48)
34	OIL - C.T.	0.00	0.00	0.00	0.00	13.72	0.00	13.72	100.00
35	TOTAL ($/MMBTU)	3.60	3.42	0.18	5.26	3.44	3.71	(0 27)	(7.28)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,888	11,056	832	7.53	11,414	10,791	623	5.77
37	GAS - Generation (1)	7,050	7,056	(6)	(0.09)	7,287	6,992	295	4.22
38	OIL - C.T.	0	0	0	0.00	19,434	0	19,434	100.00
39	TOTAL (BTU/KWH)	9,024	8,241	783	9.50	9,417	9,025	392	4.34
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	3.77	3.34	0.43	12.87	3.95	3.56	0 39	10.96
41	GAS	2.89	2.61	0.28	10.73	2.48	3.10	(0.62)	(20.00)
42	LANDFILL GAS	3.35	3.13	0.22	7.03	3.20	3.10	0.10	3.23
43	OIL - C.T.	0.00	0.00	0.00	0.00	26.66	0.00	26.66	100.00
44	TOTAL (¢/KWH)	3.25	2.82	0.43	15.25	3.24	3.35	(0.11)	(3.28)

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2016

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2016	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(722)	0.0	72.6	0.0	0	Coal	0	0	0	0	0.00	0 00
2				0					Gas-G	0	1,027	(1)	0	0.00	0 00
3									Gas-S	0	1,027	1	0		0 00
4									Oil-S	0	0	0	0		0 00
5	Crist 5		75	(723)	0.0	72.0	0.0	0	Coal	0	0	0	0	0.00	0 00
6				0					Gas-G	0	1,027	0	0	0.00	0 00
7									Gas-S	0	1,027	0	0		0 00
8									Oil-S	0	0	0	0		0 00
9	Crist 6		299	82,150	36.9	68.7	53.8	11,316	Coal	40,575	11,455	929,573	2,825,067	3.44	69.63
10				0					Gas-G	0	1,027	0	0	0.00	0 00
11									Gas-S	19,545	1,027	20,073	148,821		7.61
12									Oil-S	49	0	0	3,061		62.47
13	Crist 7		475	86,524	24.5	45.9	51.4	10,830	Coal	40,999	11,428	937,073	2,854,588	3.30	69.63
14				0					Gas-G	0	1,027	0	0	0.00	0 00
15									Gas-S	54,963	1,027	56,447	418,506		7.61
16									Oil-S	562	0	0	35,407		63 00
17	Smith 1		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0 00
18									Oil-S	0	0	0	0		0.00
19	Smith 2		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	0	0	0		0.00
21	Smith 3		584	366,188	84.3	97.9	92.7	7,050	Gas-G	2,520,990	1,024	2,581,494	10,581,409	2.89	4 20
22	Smith A	(2)	40	(6)	0.0	98.9	0.0	0	Oil	0	0	0	0	0.00	0.00
23	Other Generation			5,708									177,777	3.11	0.00
24	Perdido			2,184					Landfill Gas				73,069	3.35	0.00
25	Daniel 1	(1)	255	49,468	26.1	88.8	29.0	12,365	Coal	30,300	10,093	611,654	1,791,042	3.62	59.11
26									Oil-S	713	0	0	44,840		62.89
27	Daniel 2	(1)	255	35,755	18.8	100.0	30.6	12,480	Coal	22,622	9,863	446,215	1,337,163	3.74	59.11
28									Oil-S	295	0	0	18,582		62.99
29	Total		2,058	626,526	40.9	78.9	53.4	9,024				5,582,529	20,309,331	3.24	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,022)	
	Coal Additive - Daniel	40,615	
	Recoverable Fuel	20,345,925	3.25

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS **SCHEDULE A-5**
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2016

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	972	942	30	3.18	17,700	9,121	8,579	94.06
3	UNIT COST ($/BBL)	70.16	66 29	3 87	5.84	58.59	76.32	(17.73)	(23.23)
4	AMOUNT ($)	68,194	62,447	5,747	9.20	1,036,996	696,154	340,842	48.96
5	*BURNED :*								
6	UNITS (BBL)	1,619	944	675	71.50	18,835	9,498	9,337	98.30
7	UNIT COST ($/BBL)	62.93	65 02	(2 09)	(3.21)	62.95	69.42	(6.47)	(9.32)
8	AMOUNT ($)	101,890	61,381	40,509	66.00	1,185,696	659,398	526,298	79.81
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	3,765	4,233	(468)	(11.06)	3,765	4,233	(468)	(11.06)
11	UNIT COST ($/BBL)	62.92	76.17	(13 25)	(17.40)	62.92	76.17	(13 25)	(17.40)
12	AMOUNT ($)	236,900	322,447	(85,547)	(26.53)	236,900	322,447	(85,547)	(26.53)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	184,738	64,000	120,738	188.65	1,744,479	1,699,742	44,737	2.63
16	UNIT COST ($/TON)	63.48	59 84	3.64	6.08	71.24	69.34	1 90	2.74
17	AMOUNT ($)	11,727,970	3,829,784	7,898,186	206.23	124,268,853	117,853,252	6,415,601	5.44
18	*BURNED :*								
19	UNITS (TONS)	134,496	42,854	91,642	213.85	1,909,330	1,679,296	230,034	13.70
20	UNIT COST ($/TON)	65.49	64 26	1 23	1.91	74.28	75.01	(0.73)	(0.97)
21	AMOUNT ($)	8,807,860	2,753,856	6,054,004	219.84	141,817,746	125,958,221	15,859,525	12.59
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	534,194	480,955	53,239	11.07	534,194	480,955	53,239	11.07
24	UNIT COST ($/TON)	63.70	65 85	(2.15)	(3.26)	63.70	65.85	(2.15)	(3.26)
25	AMOUNT ($)	34,028,064	31,670,604	2,357,460	7.44	34,028,064	31,670,604	2,357,460	7.44
26	DAYS SUPPLY	33	30	3	10.00				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,784,780	2,629,914	154,866	5.89	25,991,100	24,595,615	1,395,485	5.67
29	UNIT COST ($/MMBTU)	4.13	3.68	0.45	12.23	3.53	4.49	(0 96)	(21.38)
30	AMOUNT ($)	11,493,687	9,686,911	1,806,776	18.65	91,704,932	110,325,621	(18,620,689)	(16.88)
31	*BURNED :*								
32	UNITS (MMBTU)	2,658,014	2,629,914	28,100	1.07	25,543,482	24,595,615	947,867	3.85
33	UNIT COST ($/MMBTU)	4.19	3.68	0.51	13.86	3.48	4.49	(1 01)	(22.49)
34	AMOUNT ($)	11,148,633	9,686,911	1,461,722	15.09	88,911,127	110,325,621	(21,414,494)	(19.41)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	1,116,053	0	1,116,053	100.00	1,116,053	0	1,116,053	100.00
37	UNIT COST ($/MMBTU)	4.10	0 00	4.10	100.00	4.10	0.00	4.10	100.00
38	AMOUNT ($)	4,574,599	0	4,574,599	100.00	4,574,599	0	4,574,599	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	1,408	0	1,408	100.00
41	UNIT COST ($/BBL)	0.00	0 00	0 00	0.00	67.25	0.00	67 00	100.00
42	AMOUNT ($)	0	0	0	0.00	94,685	0	94,685	100.00
43	*BURNED :*								
44	UNITS (BBL)	0	0	0	0.00	1,219	0	1,219	100.00
45	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	101.17	0.00	101.17	100.00
46	AMOUNT ($)	0	0	0	0.00	123,322	0	123,322	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,922	6,749	173	2.56	6,922	6,749	173	2.56
49	UNIT COST ($/BBL)	97.83	101.49	(3.66)	(3.61)	97.83	101.49	(3.66)	(3.61)
50	AMOUNT ($)	677,210	684,955	(7,745)	(1.13)	677,210	684,955	(7,745)	(1.13)
51	HOURS SUPPLY	78	76	2	2.63				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2016

CURRENT MONTH

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) ¢ / KWH FUEL COST	(6) (b) ¢ / KWH TOTAL COST	(7) (5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(8) (5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		123,675,000	0	123,675,000	2.13	2.51	2,634,000	3,100,000
2	Various	Economy Sales	10,994,000	0	10,994,000	2.13	2.60	234,000	286,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	47,000	47,000
4	TOTAL ESTIMATED SALES		134,669,000	0	134,669,000	2.16	2.55	2,915,000	3,433,000
	ACTUAL								
5	Southern Company Interchange		389,084,520	0	389,084,520	2.51	2.79	9,758,070	10,860,309
6	A.E.C.	External	550,807	0	550,807	2.57	3.31	14,174	18,258
7	AECI	External	0	0	0	0.00	0.00	0	0
8	CARGILE	External	591,232	0	591,232	2.50	3.07	14,803	18,161
9	DUKE PWR	External	76,992	0	76,992	1.50	2.32	1,152	1,790
10	EAGLE EN	External	1,301,789	0	1,301,789	2.65	3.58	34,456	46,567
11	ENDURE	External	0	0	0	0.00	0.00	0	0
12	EXELON	External	1,682,017	0	1,682,017	1.98	2.65	33,267	44,586
13	FPC	External	0	0	0	0.00	0.00	0	0
14	FPL	External	153,984	0	153,984	2.16	3.10	3,332	4,773
15	FPLEPM	External	0	0	0	0.00	0.00	0	0
16	JPMVEC	External	0	0	0	0.00	0.00	0	0
17	MERCURIA	External	0	0	0	0.00	0.00	0	0
18	MISO	External	2,078,862	0	2,078,862	2.24	2.94	46,483	61,049
19	MORGAN	External	523,916	0	523,916	2.54	3.28	13,327	17,176
20	NCEMC	External	50,686	0	50,686	2.67	3.61	1,351	1,828
21	NCMPA01	External	0	0	0	0.00	0.00	0	0
21	NOBLEAGP	External	153,968	0	153,968	2.94	4.23	4,533	6,518
22	OPC	External	6,416	0	6,416	3.54	5.40	227	346
23	ORLANDO	External	135,570	0	135,570	2.47	3.58	3,349	4,851
24	PJM	External	675,731	0	675,731	2.68	3.62	18,081	24,464
25	REMC	External	0	0	0	0.00	0.00	0	0
26	SCE&G	External	180,269	0	180,269	2.44	2.97	4,394	5,357
27	SEC	External	109,712	0	109,712	2.74	3.76	3,008	4,129
28	SEPA	External	4,917,707	0	4,917,707	2.34	3.43	115,215	168,798
29	TAL	External	82,440	0	82,440	2.64	3.41	2,176	2,815
30	TEA	External	2,142,090	0	2,142,090	2.43	3.08	52,084	65,949
31	TECO	External	70,576	0	70,576	2.52	3.67	1,782	2,589
32	TENASKA	External	0	0	0	0.00	0.00	0	0
33	TVA	External	1,285,054	0	1,285,054	2.95	3.95	37,950	50,770
34	WRI	External	538,041	0	538,041	7.61	3.06	40,945	16,459
35	Less: Flow-Thru Energy		(17,127,590)	0	(17,127,590)	2.42	2.42	(413,635)	(413,635)
36	SEPA		93,000	93,000	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	77,543	77,543
38	Other transactions including adj.		92,439,239	113,667,260	(21,228,021)	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		481,797,028	113,760,260	368,036,768	2.05	2.29	9,868,067	11,013,906
40	Difference in Amount		347,128,028	113,760,260	233,367,768	(0.11)	(0.26)	6,953,067	7,580,906
41	Difference in Percent		257.76	0.00	173.29	(5.09)	(10.20)	238 53	220.82

Note: (1) Economy Sales Gains in column 8 are included in he total cost for each counterparty and are not included as depicted on line 37

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2016

PERIOD TO DATE

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) ¢ / KWH FUEL COST	(6) (b) ¢ / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		2,774,329,000	0	2,774,329,000	2 35	2.75	65,332,000	76,425,000
2	Various	Economy Sales	118,508,000	0	118,508,000	2 25	2.69	2,668,000	3,187,000
3		Gain on Econ. Sales	0	0	0	0 00	0.00	552,000	552,000
4	TOTAL ESTIMATED SALES		2,892,837,000	0	2,892,837,000	2 37	2.77	68,552,000	80,164,000
	ACTUAL								
5	Southern Company Interchange		2,785,891,922	0	2,785,891,922	2.40	2.69	66,734,776	74,983,120
6	A.E.C.	External	3,395,189	0	3,395,189	2 36	3.12	80,169	105,800
7	AECI	External	0	0	0	0 00	0.00	46	0
8	CARGILE	External	3,380,934	0	3,380,934	3.49	3.45	117,897	116,619
9	DUKE PWR	External	374,373	0	374,373	2.48	4.20	9,298	15,725
10	EAGLE EN	External	5,521,096	0	5,521,096	2.42	3.11	133,747	171,786
11	ENDURE	External	281,086	0	281,086	3 29	5.23	9,258	14,698
12	EXELON	External	3,196,551	0	3,196,551	2.63	2.89	84,137	92,424
13	FPC	External	730,510	0	730,510	2 80	4.67	20,467	34,094
14	FPL	External	7,803,661	0	7,803,661	2 83	4.28	220,885	334,093
15	FPLEPM	External	95,344	0	95,344	2 32	3.35	2,215	3,191
16	JPMVEC	External	226,163	0	226,162	0.00	3.70	0	8,373
17	MERCURIA	External	496,714	0	496,714	3.73	2.90	18,548	14,390
18	MISO	External	17,693,809	0	17,693,809	1.85	2.61	327,562	461,990
19	MORGAN	External	6,024,074	0	6,024,074	2.30	2.88	138,312	173,407
20	NCEMC	External	470,139	0	470,139	2.33	2.74	10,964	12,892
21	NCMPA01	External	11,229	0	11,229	3.24	4.06	364	456
22	NOBLEAGP	External	153,968	0	153,968	5.46	4.23	8,413	6,518
23	OPC	External	561,398	0	561,398	2.41	3.70	13,517	20,757
24	ORLANDO	External	3,470,451	0	3,470,451	2.77	4.06	96,197	140,956
25	PJM	External	12,405,448	0	12,405,448	1 92	3.16	238,180	392,515
26	REMC	External	4,301	0	4,301	2 55	4.50	110	194
27	SCE&G	External	12,176,102	0	12,176,102	2 22	2.74	270,776	333,770
28	SEC	External	1,484,124	0	1,484,124	2.74	3.91	40,706	58,076
29	SEPA	External	20,916,938	0	20,916,938	2 28	3.09	476,487	645,894
30	TAL	External	699,139	0	699,139	2.60	3.55	18,144	24,824
31	TEA	External	15,583,734	0	15,583,734	2.15	2.83	334,978	441,376
32	TECO	External	740,781	0	740,781	2.65	3.65	19,654	27,045
33	TENASKA	External	8,277	0	8,277	2.88	4.34	239	359
34	TVA	External	8,004,173	0	8,004,173	2.82	4.22	225,948	337,543
35	WRI	External	3,449,682	0	3,449,682	3.38	2.60	116,527	89,750
36	Less: Flow-Thru Energy		(117,757,436)	0	(117,757,436)	2.25	2.25	(2,645,462)	(2,645,462)
37	SEPA		15,112,000	15,112,000	0	0.00	0.00	0	0
38	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	524,920	524,921
39	Other transactions including adj.		2,508,718,417	1,358,876,554	1,149,841,863	0 00	0.00	0	0
40	TOTAL ACTUAL SALES		5,321,324,291	1,373,988,555	3,947,335,736	1 27	1.44	67,647,977	76,417,171
41	Difference in Amount		2,428,487,291	1,373,988,555	1,054,498,736	(1.10)	(1.33)	(904,023)	(3,746,829)
42	Difference in Percent		83 95	0.00	36.45	(46.41)	(48.01)	(1.32)	(4.67)

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 38

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: DECEMBER 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2016

CURRENT MONTH

(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1 Total Payment to Qualified Facilities		13,731,000	0	0	0	2.59	2.59	355,000
ACTUAL								
2 Bay County/Engen, LLC	Contract	5,049,000	0	0	0	3.52	3.52	177,630
3 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	3,125
4 Ascend Performance Materials	COG 1	19,633,504	0	0	0	2.67	2.67	523,979
5 International Paper	COG 1	9,000	0	0	0	2.68	2.68	241
6 TOTAL		24,691,504	0	0	0	2.86	2.86	704,975
7 Difference in Amount		10,960,504				0.27	0.27	349,975
8 Difference in Percent		79.82				10.42	10.42	98.58

PERIOD-TO-DATE

(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1 Total Payment to Qualified Facilities		182,598,000	0	0	0	2.75	2.75	5,026,000
ACTUAL								
2 Bay County/Engen, LLC	Contract	57,117,000	0	0	0	3.52	3.52	2,009,534
3 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	3,265
4 Ascend Performance Materials	COG 1	169,872,504	0	0	0	2.45	2.45	4,159,099
5 International Paper	COG 1	635,000	0	0	0	2.45	2.45	15,534
6 TOTAL		227,624,504	0	0	0	2.72	2.72	6,187,431
7 Difference in Amount		45,026,504				(0.03)	(0.03)	1,161,431
8 Difference in Percent		24.66				(1.09)	(1.09)	23.11

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2016

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	59,624,000	2.30	1,370,000	1,094,610,000	2.58	28,205,000
2	Economy Energy	3,923,000	2.55	100,000	49,959,000	2.74	1,368,000
3	Other Purchases	421,071,000	2.99	12,576,000	5,818,290,000	2.98	173,311,000
4	TOTAL ESTIMATED PURCHASES	484,618,000	2.90	14,046,000	6,962,859,000	2.91	202,884,000
	ACTUAL						
5	Southern Company Interchange	96,361,960	2.70	2,601,131	1,383,156,204	2.54	35,194,336
6	Non-Associated Companies	40,709,407	0.56	227,538	706,690,675	0.73	5,188,522
7	Purchased Power & Renewable Agreement Energy	496,482,000	3.08	15,316,310	5,860,539,000	2.56	149,783,698
8	Other Wheeled Energy	78,000	0.00	N/A	1,480,439,000	0.00	N/A
9	Other Transactions	57,252,540	0.01	8,239	532,002,637	0.03	159,833
10	Less: Flow-Thru Energy	(17,127,590)	2.68	(458,212)	(117,757,436)	2.49	(2,937,222)
11	TOTAL ACTUAL PURCHASES	673,756,317	2.63	17,695,006	9,845,070,080	1.90	187,389,167
12	Difference in Amount	189,138,317	(0.27)	3,649,006	2,882,211,080	(1.01)	(15,494,833)
13	Difference in Percent	39.03	(9.31)	25.98	41.39	(34.71)	(7.64)

2016 CAPACITY CONTRACTS
GULF POWER COMPANY

Capacity Costs ($)

		CONTRACT	TERM														
A.	CONTRACT/COUNTERPARTY	TYPE	Start	End	January [1]	February [2]	March	April	May [2]	June	July	August	September	October	November [1]	December [1]	YTD
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	(17,016)	1,445	(23,747)	31,189	4,868	0	0	0	0	(2,990)	(648)	(25,920)	(32,819)
2	Power Purchase Agreements & Other Confidential Agreements				7,372,084	7,372,046	7,372,277	7,371,610	7,421,610	7,388,259	7,202,997	7,203,819	7,203,408	7,203,408	7,144,482	7,203,408	87,459,408
				Total	7,355,068	7,373,491	7,348,530	7,402,799	7,426,478	7,388,259	7,202,997	7,203,819	7,203,408	7,200,418	7,143,834	7,177,488	87,426,589

Capacity Costs (MW)

B.	CONTRACT/COUNTERPARTY	TYPE	Start	End	January [1]	February [2]	March	April	May [2]	June	July	August	September	October	November [1]	December [1]
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	(23)	0	(73)	157	0	0	0	0	0	(18)	(1)	(159)
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies

(1) Southern Intercompany Interchange reserve sharing charge includes prior month true up
(2) Southern Intercompany Interchange reserve sharing prior month true up only

Contract Coal Suppliers	**Tons Received** [1][2]	
Foresight Coal Sales (Plant Crist)	558,484	
TOTAL Contract Coal		558,484

Spot Coal Suppliers	**Tons Received** [1][2]	
Glencore LTD (Plants Crist and Smith)	253,618	
Coal Marketing Corporation (Plant Crist)	294,551	
Alliance Coal Co. - Gibson County Mine (Plant Crist)	114,521	
Arch Coal Sales - Black Thunder Mine (Plant Daniel)	360,192	
Arch Coal Sales - West Elk Mine (Plant Daniel)	182,481	
TOTAL Spot Coal		1,205,362
GRAND TOTAL COAL RECEIPTS		**1,763,846**

(1) Excludes Plant Scherer.
(2) Plant Daniel tons represent Gulf's 50% share of receipts.

Schedule 2

	A	B	C	D	E
1	**Gulf Contract Coal Supplies**				
2			**Received**	**Actual**	**Weighted Avg**
3	**Supplier**	**Plant**	**Quantity (tons)**	**Heating Value**	**Price $/MMBTU)**
4	Foresight Coal Sales	Crist	558,484	11834	[redacted]
5	**Weighted Average**	**Crist**	**558,484**	**11811**	
6					
7	**Gulf Spot Coal Supplies**				
8			**Received**	**Actual**	**Weighted Avg**
9	**Supplier**	**Plant**	**Quantity (tons)**	**Heating Value**	**Price $/MMBTU)**
10	Glencore LTD	Crist	247,674	12279	[redacted]
11	Coal Marketing Corporation	Crist	294,551	12052	
12	Alliance Coal	Crist	114,521	11761	
13	**Weighted Average**	**Crist**	**656,745**	**12087**	**$3.063**
14					
15	Glencore LTD	Smith	5945	11846	[redacted]
16	**Weighted Average**	**Smith**	**5945**	**11846**	
17					
18	Arch Coal Sales (Black Thunder)	Daniel (Gulf 50%)	360192	8866	[redacted]
19	Arch Coal Sales (West Elk)	Daniel (Gulf 50%)	182481	11640	
20	**Weighted Average**	**Daniel (Gulf 50%)**	**542,672**	**9799**	**$2.817**

Schedule 3

Gulf Natural Gas Purchase Price Variance

Actual Gas Price vs. Market Gas Price

Gulf Gas Purchase data for Smith 3 and for Central Alabama from the monthly gas invoice.

	Gulf Actual Purchases MMBtu	Gas Purchases Gulf Actual Delivered Cost (Total Dollars)	Monthly Gas Hedge Settlement (Total Dollars)	Gulf Actual Gas Purchases Weighted Average Commodity $/MMBtu	Gulf Actual Gas Storage and Transportation $/MMBtu	Gulf Actual Gas Purchases Delivered Cost $/MMBtu	Gulf Actual Hedged Gas Purchases Delivered Cost $/MMBtu	FGT Zone 3 Weighted Average Market Price Commodity $/MMBtu
Jan-16	5,588,319	$ 15,656,286	$ 5,195,191	$2.30	$0.50	$2.80	$3.73	$2.29
Feb-16	4,989,568	$ 12,796,101	$ 6,107,019	$2.03	$0.53	$2.56	$3.79	$1.96
Mar-16	7,085,648	$ 15,247,985	$ 6,681,995	$1.77	$0.38	$2.15	$3.09	$1.74
Apr-16	4,309,699	$ 11,362,342	$ 5,239,140	$1.82	$0.82	$2.64	$3.85	$1.87
May-16	4,977,527	$ 12,959,125	$ 5,718,593	$1.87	$0.73	$2.60	$3.75	$1.87
Jun-16	5,881,434	$ 18,282,962	$ 4,737,258	$2.44	$0.67	$3.11	$3.91	$2.54
Jul-16	6,432,168	$ 21,775,897	$ 3,826,500	$2.82	$0.57	$3.39	$3.98	$2.83
Aug-16	6,522,052	$ 22,441,373	$ 3,888,982	$2.89	$0.55	$3.44	$4.04	$2.78
Sep-16	4,313,854	$ 16,562,107	$ 3,263,916	$3.11	$0.73	$3.84	$4.60	$2.93
Oct-16	3,376,792	$ 13,836,907	$ 3,226,726	$3.67	$0.43	$4.10	$5.05	$2.96
Nov-16	3,853,914	$ 12,154,228	$ 4,424,990	$2.72	$0.43	$3.15	$4.30	$2.46
Dec-16	5,943,232	$ 23,898,729	$ 1,750,470	$3.59	$0.43	$4.02	$4.32	$3.51
TOTAL	**63,274,207**	**$ 196,974,042**	**$ 54,060,780**	**$2.49**	**$0.62**	**$3.11**	**$3.97**	**$2.48**

Schedule 4

2016 Natural Gas Burn Cost Variance and Hedging Effectiveness

Hedging Settlement Cost from Schedule A-1

NOTE: Gas Burn Cost and Gas MMBTU's burned is billed amount for Gulf owned gas fired generation and purchase power agreement (PPA) generating units for which Gulf supplies the fuel.

	Gas Burn for Generation MMBtu	Gas Cost for Generation Actual Cost	Gulf Hedge Settlement Total $	Gas Cost for Generation Hedged Cost	Gas Cost for Generation Actual Cost $/MMBtu	Gas Cost for Generation Hedged Cost $/MMBtu
Jan-16	**5,588,319**	$ 15,656,286	$ 5,195,191	$ 20,851,477	$ 2.80	$ 3.73
Feb-16	**4,989,568**	$ 12,796,101	$ 6,107,019	$ 18,903,120	$ 2.56	$ 3.79
Mar-16	**7,085,648**	$ 15,247,985	$ 6,681,995	$ 21,929,980	$ 2.15	$ 3.09
Apr-16	**4,309,699**	$ 11,362,342	$ 5,239,140	$ 16,601,482	$ 2.64	$ 3.85
May-16	**4,997,527**	$ 12,959,125	$ 5,718,593	$ 18,677,718	$ 2.59	$ 3.74
Jun-16	**5,881,434**	$ 18,282,962	$ 4,737,258	$ 23,020,220	$ 3.11	$ 3.91
Jul-16	**6,432,168**	$ 21,775,897	$ 3,826,500	$ 25,602,397	$ 3.39	$ 3.98
Aug-16	**6,526,976**	$ 22,357,275	$ 3,888,982	$ 26,246,257	$ 3.43	$ 4.02
Sep-16	**4,529,352**	$ 16,525,676	$ 3,263,916	$ 19,789,592	$ 3.65	$ 4.37
Oct-16	**3,280,462**	$ 10,989,296	$ 3,226,726	$ 14,216,022	$ 3.35	$ 4.33
Nov-16	**3,495,074**	$ 13,544,278	$ 4,424,990	$ 17,969,268	$ 3.88	$ 5.14
Dec-16	**5,782,496**	$ 22,973,823	$ 1,750,470	$ 24,724,293	$ 3.97	$ 4.28
TOTAL	**62,898,723**	**$ 194,471,046**	**$ 54,060,780**	**$ 248,531,826**		
Weighted Average Price					**$ 3.09**	**$ 3.95**
				Variance	**0.33**	**0.24**
				Standard Deviation	**0.58**	**0.49**

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: **Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor**	)))	Docket No.: **170001-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by electronic mail this 1st day of March, 2017 to the following:

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