BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

IN THE MATTER OF: GEORGIA POWER COMPANY'S FUEL COST RECOVERY APPLICATION (FCR-25)	**DOCKET NO. 43011**

DIRECT TESTIMONY

AND EXHIBITS

OF

TOM NEWSOME, PE, CFA

PHILIP M. HAYET

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

PUBLIC DISCLOSURE VERSION

May 1, 2020

TABLE OF CONTENTS

I. BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESSES.

A. My name is Tom J. Newsome. I am the Director of Utility Finance with the Georgia Public Service Commission ("Commission"). My business address is 244 Washington St., Atlanta, Georgia, 30334.

My name is Philip Hayet. I am a Vice President and Principal of J. Kennedy and Associates, Inc. ("Kennedy and Associates"). My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q. MR. NEWSOME, WHAT ARE YOUR PRIMARY RESPONSIBILITIES WITH THE COMMISSION STAFF?

A. I am responsible for economic, financial, and cost of equity analysis and evaluations at the Commission.

Q. WHAT CONSULTING SERVICES DOES KENNEDY AND ASSOCIATES PROVIDE?

A. Kennedy and Associates provides consulting services related to electric utility system planning, resource planning, fuel auditing, production cost modeling, ratemaking, finance, accounting, and industry policy issues.

Q. PLEASE PROVIDE SUMMARIES OF YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. Summaries of our education, experience, professional certifications, and testimony appearances are provided in Exhibits STF-NH-1 and STF-NH-2, for Mr. Newsome and Mr. Hayet, respectively.

Q. IS ANYONE ELSE SUBMITTING TESTIMONY ON BEHALF OF STAFF?

A. Yes. Dr. William R. Jacobs, Jr. will file testimony regarding nuclear plant outage issues.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In this testimony, we present Staff's analysis and recommendations concerning Georgia Power's Fuel Cost Recovery ("FCR-25") filing.

II. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. We offer the following recommendations:

1) The Company should modify its proposed FCR-25 fuel rates to account for the additional over collection that has occurred through April 2020. The revised rates should go into effect June 1, 2020 through May 31, 2023.

2) The Company should be required to file its next fuel proceeding, FCR-26, no later than February 28, 2023, and new rates should go into effect June 1, 2023. The Company is expected to file its next Integrated Resource Plan in January 2022 and its next base rate case in July 2022. If either of these filings are delayed beyond 2022, then Staff recommends FCR-26 be filed in 2022. The shorter the time period there is between FCR cases would reduce the amount of data to be reviewed and would allow Staff to perform a more thorough analysis.

3) Reduce the fuel balance[1] by $4.11 million for unnecessary fuel replacement cost from

[1] The Fuel balance is the cumulative amount (in dollars) the Company has either over collected (fuel revenues exceed fuel expenses) or under collected (fuel expenses exceed fuel revenues) at a given point in time.

fossil and nuclear generation outages that were the result of clear imprudence.

4) The Company should be required to provide to Staff on June 30 and December 31 of each year updated projected monthly fuel revenues, fuel expenses, monthly over or under collections and projected fuel balances through May 31, 2023. These updates would allow Staff to more proactively monitor prospective fuel revenues and expenses and fuel balances. These updates should include at a minimum, the Company's most recent short-term natural gas price forecast. A June 30, 2020 update is not necessary since FCR-25 hearings will have been recently completed.

5) Discontinue the natural gas price hedging program. Any benefit of the hedging program protecting ratepayers from fuel expense volatility is more efficiently provided for by the stable FCR rates approve by the Commission at much lower cost to ratepayers.

6) Revise the criterion to trigger the Interim Fuel Rider. The Interim Fuel Rider would be implemented if the fuel balance is over or under collected by $150 million for three consecutive months. This revision would mitigate the impact of temporary factors that could inflate the fuel balance and provide a more structured approach to address large fuel balances between FCR cases.

III. PROJECT SCOPE

Q. PLEASE DESCRIBE THE OVERALL SCOPE OF DISCOVERY IN THIS CASE.

A. In total, three formal sets of data requests were submitted, and additional informal requests were made to the Company. During this proceeding, Staff had telephone conference calls with Company personnel, and submitted and reviewed responses to Staff discovery requests.

Q. PLEASE DESCRIBE THE PURPOSE AND CALCULATION OF THE FCR TARIFF.

A. The purpose of the FCR tariff is to collect revenues from ratepayers to cover fuel costs incurred by the Company. FCR rates are calculated to recover projected fuel costs and address the fuel balance that resulted from prior period fuel costs that were either under or over collected.

Q. WHAT AMOUNT HAS THE COMPANY DETERMINED WILL NEED TO BE RECOVERED THROUGH FCR-25 RATES FOR PROJECTED COSTS OVER THE 24 MONTH PERIOD OF JULY 1, 2020 THROUGH JUNE 30, 2022?

A. Due to a significant reduction in forecasted fuel costs, primarily lower natural gas prices, the Company projects it will need to recover $3.6 billion in FCR-25 costs for the 24-month Test Period of July 1, 2020 through June 30, 2022. This is much less than the $4.4 billion it projected in FCR-24 for the 24-month period of January 2016 through December 2017.

Q. WHAT ADJUSTMENT WILL NEED TO BE MADE FOR THE PRIOR PERIOD?

A. Prior to filing its FCR-25 Application in March, the Company developed its fuel cost projection and estimated that by May 31, 2020, immediately before the new FCR-25 rates would go into effect,[2] it will have over-collected $133 million from customers. However, the Company recently reported that as of March 31, 2020, the over-collected balance now stands at $169 million. The Company should account for this when it files its Rebuttal testimony, and it should revise its proposed Tariff with a lower rate.

Q. WHAT COSTS ARE ELIGIBLE FOR RECOVERY IN THE FCR?

[2] Typically, new rates would go into effect on the first day of the Test Period (July 1, 2020), however, in its October 11, 2018 Order Deferring Fuel Case in the FCR-24 Docket, the Commission required new rates to go into effect on June 1, 2020.

A. Cost eligibility concerns whether the costs requested for recovery are appropriate for the type of case under consideration. The Georgia statute, O.C.G.A. § 46-2-26 (a)(1) specifies what fuel costs are recoverable, and it states, "*Fuel costs" of a utility company means the cost of fuel as defined in the utility company's tariffs in effect on July 1, 1979, as such tariffs may be changed from time to time by order of the commission as provided by law*." Consequently, fuel costs recoverable in the FCR are those costs listed in the utility's most recent FCR tariff, which have been explicitly approved by the Commission.

Q. HOW ARE RECOVERABLE FUEL COSTS DEFINED IN THE FCR TARIFF?

A. GPC's prior FCR-24 Tariff and its proposed FCR-25 Tariff define recoverable fuel costs exactly the same as follows:

> Fuel Costs shall be the cost of:
>
> (1) fossil, nuclear, bio-mass (including renewable) fuel and emission allowances (including credits, offsets, taxes, tariffs or other mechanisms intended to establish a market price for carbon, carbon dioxide and/or other greenhouse gases) consumed in the Company's own plants, and the Company's share of fossil, nuclear, and bio-mass (including renewable) fuel and emission allowances (including credits, offsets, taxes, tariffs or other mechanisms intended to establish a market price for carbon, carbon dioxide and/or other greenhouse gases) consumed in jointly owned or leased plants; plus
>
> (2) the identifiable fossil, nuclear, bio-mass (including renewable) fuel and emission allowance costs (including credits, offsets, taxes, tariffs or other mechanisms intended to establish a market price for carbon, carbon dioxide and/or other greenhouse gases) associated with energy purchased for reasons other than identified in (3) below; plus
>
> (3) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost of energy; less
>
> (4) the cost of fossil, nuclear, bio-mass (including renewable) fuel and emission allowances (including credits, offsets, taxes, tariffs or other mechanisms intended to establish a market price for carbon, carbon dioxide and/or other greenhouse

gases) recovered through intersystem sales when sold on an economic dispatch basis; less
(5) retail portion of gains resulting from the sale of any emissions allowances; less
(6) seventy-five percent of net gains from wholesale market opportunity sales; plus or minus
(7) net gains and losses incurred under the Natural Gas and Oil Procurement and Hedging Program implemented in Docket No. 16134-U; plus or minus
(8) carrying costs on over or under recovered fuel balance calculated at the Company's short term debt rate and excluding the first $15 million of any under recovered cost; plus or minus
(9) other costs or credits as determined by the Commission for inclusion in, or reduction of, recoverable fuel costs.

Minimum Filing Requirements

Q. PLEASE DISCUSS THE CHANGES TO THE MINIMUM FILING REQUIREMENTS THAT WERE IMPLEMENTED SINCE FCR-24?

A. The Commission's FCR-24 Order included a requirement that the Company, Staff and other interested parties collaborate in a review of FCR Minimum Filing Requirements ("MFR"). Staff worked closely with the Company to revise both the historic and projected MFRs, and the Commission approved the modifications on June 19, 2018

Q. COULD FURTHER STEPS BE TAKEN TO IMPROVE THE QUALITY OF THE MFRS?

A. Yes, Staff believes there are still additional modifications that could help to improve the FCR process. The MFRs provide critical information in a timely manner that is relied on by Staff and other parties during fuel proceedings. Georgia law only allows ninety (90) days for an FCR proceeding to be completed, which is challenging. Staff recommends that the Commission require the Company, Staff and other interested parties to continue to collaborate to improve the MFRs. Some additional items that would make the MFR process more informative and efficient include:

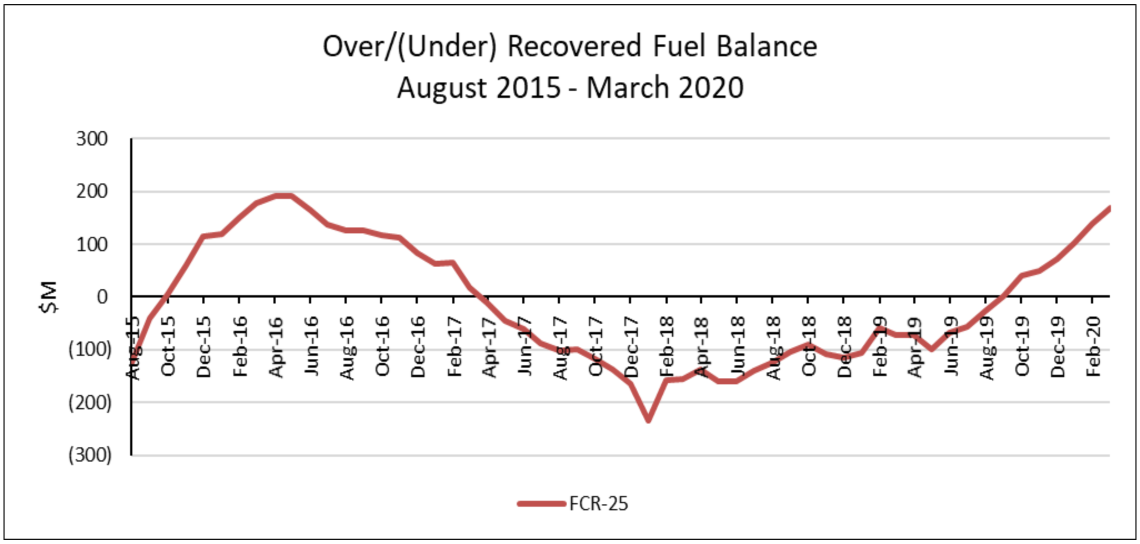
1) Calculation of opportunity sales profit margins for the historical period and the projected period.
2) Monthly spot prices vs. marginal replacement fuel costs for all coal plants in the historical period.
3) Costs and generation by program of items included in the FCR tariff that include renewable, DSM, cogeneration, etc., and all costs under the category "(9) other costs or credits as determined by the Commission for inclusion in, or reduction of, recoverable fuel costs" on page 2 of the FCR-25 tariff.
4) General ledger entries for all accounts recovered in the FCR during the historical period.
5) Annual projected budget reports created during the historical period.
6) Monthly operations reports created during the historical period.

<u>Fuel Balance and Proposed Rates</u>

Q. WHAT HAPPENED TO THE FUEL BALANCE SINCE FCR-24 RATES FIRST WENT INTO EFFECT?

A. At the start of the historic review period for FCR-25 in August 2015, shortly before FCR-24 rates went into effect, the Company had under-recovered its fuel costs by about $125 million. Between August 2015 and March 2020, natural gas prices declined significantly, and the Company's under-recovered balanced decreased and turned into an over-recovered balance of $169 million as of March 31, 2020, as seen in the following figure.

Figure 1



Q. FIGURE 1 INDICATES THAT THE FUEL BALANCE MOVED BETWEEN BEING UNDER AND OVER-RECOVERED DURING THE PERIOD. WHAT CAUSED THAT TO OCCUR?

A. Natural gas costs fell more sharply than expected when FCR-24 rates went into effect on January 1, 2016. Shortly after the new rates went into effect, the Company recognized it would end up significantly over-collecting revenues based on the approved rates. As a result, on April 14, 2016, the Company voluntarily filed an Interim Fuel Rider Plan ("IFR-2") requesting the Commission to approve a reduction in the FCR rates. The Commission approved the request and ordered the IFR-2 rates to be in effect from June 1, 2016 through December 31, 2017, assuming that FCR-25 rates would have been implemented by then.[3]

Q. WHAT HAPPENED TO THE IFR-2 RATES GIVEN THE FCR-25 PROCEEDING WAS ULTIMATELY DELAYED UNTIL 2020?

---

[3] See Commission Order June 5, 2018 in Docket No. 39638.

A. At its December 16, 2016 Administrative Session, the Commission deferred the FCR-25 filing date to allow "the Commission to review Georgia Power's fuel cost recovery position by no later than September 1, 2018, and determine at such time whether a fuel cost recovery proceeding is needed or whether the current rate should remain in place for an additional period of time."[4] Despite the delay in FCR-25, Georgia Power was still obligated to end IFR-2 rates on December 31, 2017, and therefore, beginning January 1, 2018, Georgia Power reverted back to the original FCR-24 rates.[5]

Q. WHAT HAPPENED NEXT?

A. On October 11, 2018, the Commission issued an order requiring the Company to make its FCR-25 filing the first quarter of 2020 such that new rates would become effective on June 1, 2020, which the Company did on March 9, 2020.

Q. WHAT ARE THE FCR-25 RATES THAT THE COMPANY HAS PROPOSED IN THIS PROCEEDING?

A. The Company has proposed the following rates for FCR-25 to recover projected fuel cost and address the fuel balance.

Table 1

	Average Rate (cents / kWh)	Transmission	Primary	Secondary
Winter (Oct-May)	2.4825	2.4485	2.4710	2.4950
Summer (June-Sept)	2.5139	2.4795	2.5022	2.5266

[4] See background discussed in the Order Deferring Fuel Case, Docket No. 39638, dated Oct 11, 2018.

[5] The Company notified the Commission on February 14, 2018, that it had exceeded the IFR threshold of $200 million (under-recovered) in January 2018, but it explained that by reverting back to FCR-24 rates it expected the under-recovered balance would trend towards zero by the end of 2018.

Q. WHAT DOES TRANSMISSION, PRIMARY AND SECONDARY REPRESENT?

A. The voltage level at which customers receive electric service. Large industrial customers are typically billed at FCR transmission rates as they take service at high voltage levels. In contrast residential customers are billed at FCR secondary rates as they take service at low voltage levels. The difference in FCR transmission, primary and secondary rates is a function of expected lines losses as the power is distributed from generation plants to customers.

Q. HOW DO THE PROPOSED FCR-25 RATES COMPARE TO THE CURRENT FCR-24 RATES?

A. Company witness Ms. Adams indicated that the average FCR-25 winter and summer rates are approximately 13% and 20% lower than the average winter and summer FCR-24 rates, respectively.[6] She also noted that, on average, there would be a decrease of approximately 4% or $5.02 per month on the total bill (including base and other rate components) of a typical 1,000 kWh residential customer.[7]

IV. HISTORICAL REVIEW PERIOD

<u>**Historic Variance Analysis**</u>

Q. HAVE YOU EVALUATED THE VARIANCE BETWEEN BUDGETED COSTS AND ACTUAL HISTORIC COSTS?

[6] Sarah Adams Direct Testimony, beginning at pg. 5, ln. 7.
[7] Sarah Adams Direct Testimony, beginning at pg. 2, ln. 22.

A. Yes, we compared budgeted costs and generation that were projected at the time of the FCR-24 proceeding to the actual costs and generation that the Company supplied as part of the MFRs (MFRH-2) in this proceeding. These costs occurred over the 53 month historic period for FCR-25 covering the period of August 2015 – December 2019.[8] The following table contains a summary of the differences between actual and projected costs and generation.

Table 2

Expense and Generation Variance									
Note: Negative means Actual Less than Projected									
	$M			**GWh**			**$/MWh**		
Load	Actual	Projected	Variance	Actual	Projected	Variance	Actual	Projected	Variance
Retail Load	10,064	12,776	(2,712)	372,218	393,804	(21,586)	27.0	32.4	(5.4)
Wholesale Load	460	304	156	17,094	10,117	6,977	26.9	30.1	(3.2)
Losses	-	-	-	15,708	20,171	(4,463)	-	-	-
Net Load	10,524	13,080	(2,557)	405,019	424,092	(19,073)	26.0	30.8	(4.9)
Generation									
Gas - GPC + Purchases	4,113	5,656	(1,542)	155,516	162,364	(6,848)	26.5	34.8	(8.4)
GPC Steam	2,950	3,936	(986)	90,116	111,605	(21,488)	44.1	67.0	(22.9)
Pool and Misc. Purchases	1,947	1,866	81	66,882	58,707	8,175	29.1	31.8	(2.7)
GPC Nuclear	600	638	(38)	72,416	72,299	117	8.3	8.8	(0.5)
Biomass Purchases	292	248	45	5,490	5,433	57	53.2	45.6	7.6
Solar - GPC + Purchases	258	389	(131)	5,498	5,243	255	46.9	74.2	(27.3)
Wind Purchases	129	129	(0)	2,873	2,877	(4)	44.9	44.9	(0.0)
GPC Hydro	-	-	-	6,228	5,563	665	-	-	-
Miscellaneous	(10)	(13)	3	-	-	-	-	-	-
Net Generation	10,279	12,849	(2,570)	405,019	424,092	(19,073)	26.9	34.6	(7.7)

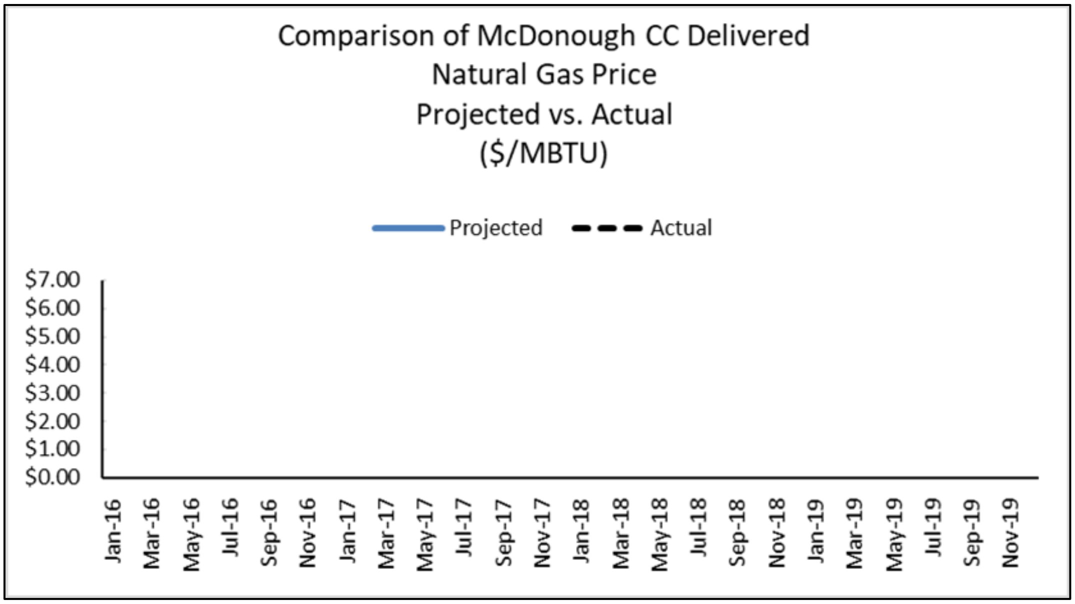
Over the entire period, the total net fuel cost, including all categories of energy supplied to meet load, was about $2.6 billion (20%) below budget. Several drivers contributed to fuel costs being lower than expected, including the fact that total load requirements (retail, wholesale, and losses) were lower than projected by 19.1 Terawatt-

[8] Pursuant to an ongoing Commission requirement that there be no gap in the review process (FCR-20, Docket 26794, May 23, 2008 Order), the historic period for FCR-26 shall begin in January 2020.

hours (TWh)[9] (4.5%). Another major factor that contributed to the lower fuel cost was much lower natural gas prices. The following chart illustrates this as it compares Plant McDonough monthly delivered natural gas prices that were forecast at the time of the FCR-24 proceeding to the actual prices incurred by the Company.[10]

BEGIN TRADE SECRET

Figure 2



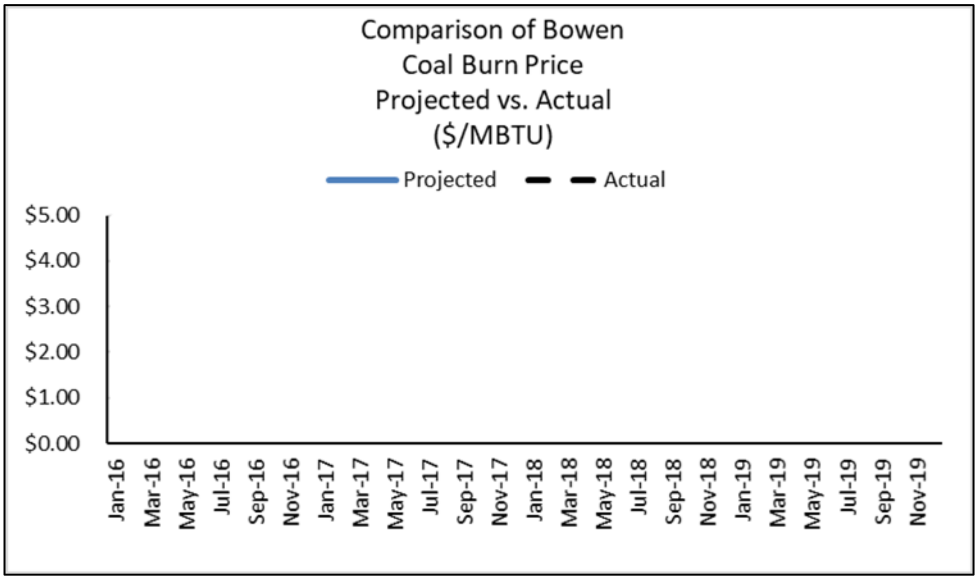
END TRADE SECRET

Another contributing factor was that actual coal fuel costs were lower than projected. The following chart illustrates this as it compares the Bowen monthly coal prices that were forecast at the time of the FCR-24 proceeding to the actual prices incurred by Georgia Power.[11]

[9] One terawatt-hour is equal to 1 million megawatt-hours, or 1,000 gigawatt-hours.
[10] Delivered fuel costs are inclusive of pipeline transportation charges.
[11] These coal prices are inclusive of transportation charges.

BEGIN TRADE SECRET

Figure 3



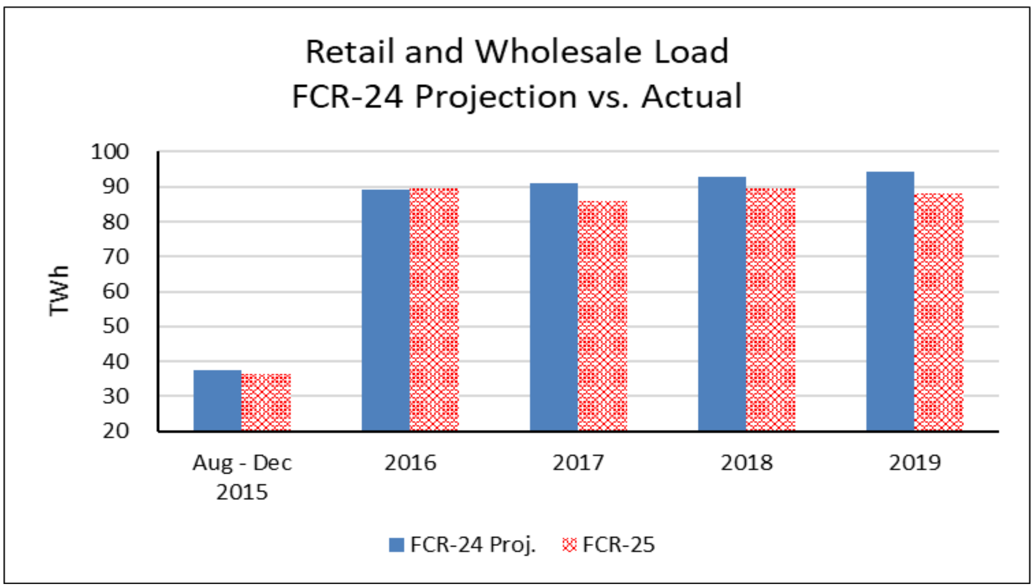
END TRADE SECRET

Of the total $2.6 billion savings in net total fuel costs during the historic period, $1.5 billion resulted from lower natural gas related fuel costs, and about another $1 billion resulted from lower coal costs. Renewable energy costs, including GPC-owned renewable resources and renewable purchases, and nuclear fuel costs were under budget by $125 million, as a result of the rapid decrease in the price of solar energy, as well as a lower than anticipated price of nuclear fuel. Pool purchases from the Southern Company system, as well as economy and miscellaneous purchases were above budget by $80 million. Other miscellaneous expenses, such as emission allowances, carrying costs, and economy energy profits were over budget by about $3 million.

Q. HOW DID THE ACTUAL LOAD COMPARE TO THE FCR-24 BUDGET LOAD OVER THE HISTORIC PERIOD?

A. Actual retail load was 21.6 TWh (5.5%) below budget, and losses were lower than budget by 4.5 TWh. This was offset somewhat by the fact that actual wholesale sales were greater than budget by about 7.0 TWh, and the result was that total load requirements were below budget by about 19.1 TWh (4.5%). Most of the variance in retail and wholesale load was due to an over-projection of load growth that occurred in 2017, 2018, and 2019, as seen in the figure below.

Figure 4



Q. HOW DID THE GENERATION SOURCES COMPARE TO THE BUDGET OVER THE HISTORIC PERIOD?

A. Because of the reduction in load, 19.1 TWh less generation was needed. Despite the reduction in needed generation, some types of resources produced less energy than expected, and others more. For example, GPC coal units supplied 21.5 TWh less, and natural gas generation from owned resources and purchases supplied 6.8 TWh less than budget. Purchases from the Southern Company pool, economy, and miscellaneous sources supplied 8.2 TWh more than budget. Nuclear and renewable sources (solar, wind, hydro, and biomass) also supplied more energy than expected in the budget by 1.1 TWh.

Q. HOW HAS GEORGIA POWER'S ACTUAL MIX OF GENERATION CHANGED OVER TIME?

A. Yes. The following table compares the sources of generation and costs for that resources that were used to supply the actual load during the FCR-24 historic period (March 2012 – July 2015) to the FCR-25 historic period (August 2015 – December 2019).

Table 3

Fuel Source Comparison
FCR-24 vs. FCR-25

RESOURCE SOURCE	FCR-24 Mar 2012 - Jul 2015			FCR-25 Aug 2015 - Dec 2019		
	Total Cost ($M)	Percent Cost	Percent Generation	Total Cost ($M)	Percent Cost	Percent Generation
Natural Gas	$3,592	35.8%	35.3%	$4,113	40.0%	38.4%
Steam - Coal	$4,218	42.0%	28.2%	$2,950	28.7%	22.2%
Nuclear	$484	4.8%	18.1%	$600	5.8%	17.9%
Purchase Power	$1,702	17.0%	16.7%	$1,947	18.9%	16.5%
Hydro	$0	0.0%	1.4%	$0	0.0%	1.5%
Solar	$7	0.1%	0.1%	$258	2.5%	1.4%
Biomass	$33	0.3%	0.3%	$292	2.8%	1.4%
Wind	$0	0.0%	0.0%	$129	1.3%	0.7%
Miscellaneous	-$5	0.0%	0.0%	-$10	-0.1%	0.0%
Total	$10,032	100.0%	100.0%	$10,279	100.0%	100.0%

On average, fuel costs were considerably lower during the 53 month FCR-25 period ($194 million per month) compared to the 40 month FCR-24 period ($250 million per month). These results illustrate the changes that the Georgia Power System has experienced over time. For the most part, nuclear generation and purchased power as a percentage of total generation and cost have remained about the same in the two periods, while coal, natural gas and renewable generation (wind, solar, biomass, and hydro) have changed quite a bit. As a result of both coal unit retirements and lower gas prices, gas-fired generation has displaced coal-fired generation significantly. In addition, renewable generation has increased significantly as well, from 1.8% to 5% of total generation.

Green Energy Program

Q. DOES THE COMPANY'S GREEN ENERGY PROGRAM IMPACT FCR RATES?

A. Yes. The costs of purchasing renewable energy are included in FCR costs. Revenues from participating customers in the Company's Green Energy riders are used to offset program costs first, and then are used to offset the cost of purchasing renewable energy included in the FCR. These programs include the Company's ASI, REDI, Simple Solar, Green Energy Program, RNR, and SP programs as well as QF purchases. The types of purchased energy sources in these programs include Solar, Biomass, Hydro, Landfill Gas, Wind, and other miscellaneous sources referred to as Mixed types of renewable energy. Staff conducted a high-level review of these green energy programs, including reviewing information the Company provided in data responses. Over the FCR-25 historical period, the Company spent about $858 million in total and purchased approximately 14,635 GWh of energy on these renewable energy programs, leading to an average price of $59/MWh. Table 4 below focuses on the solar, biomass and wind purchases in these programs.

Table 4

Renewable Resource Types									
	Solar			Biomass			Wind		
	$M	GWH	$/MWH	$M	GWH	$/MWH	$M	GWH	$/MWH
2015	$11	91	$116	$18	370	$47	-	0	-
2016	$57	776	$73	$44	919	$47	$30	720	$42
2017	$95	1,510	$63	$68	1,191	$57	$32	718	$44
2018	$94	1,506	$63	$65	1,123	$58	$33	717	$46
2019	$100	1,568	$64	$87	1,384	$63	$34	717	$48

As indicated by the table above, the price of solar declined substantially throughout the historical period, leading to an average price of $65/MWh, and the amount of solar energy purchases increased significantly during the period. Wind and biomass programs have seen increases in the price of energy, and the amount of energy from biomass purchases increased considerably over the historical period, while wind purchases remained fairly constant during the period.

<u>Coal Inventory Review</u>

Q. ARE THERE SPECIFIC INVENTORY TARGETS THAT THE COMPANY IS OBLIGATED TO MEET?

A. Yes. In FCR-22, the Company requested, and the Commission approved the Company's request to widen the inventory target range from keeping between [redacted] to [redacted] days of inventory to keeping between [redacted] and [redacted] days of inventory at its coal-fired power plants.

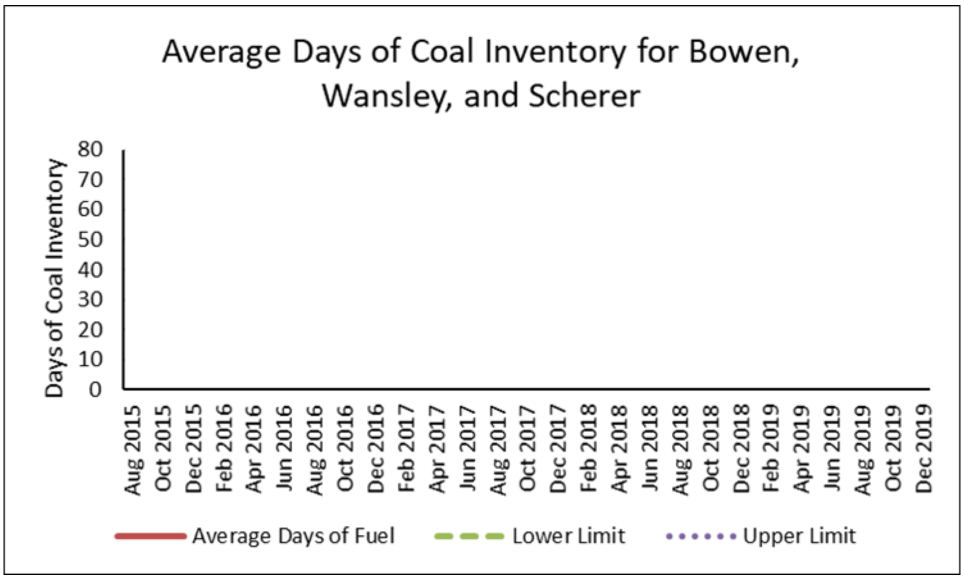
Q. DID THE COMPANY MEET THESE TARGETS IN THE HISTORIC PERIOD OF FCR-25?

A. The Company was generally compliant with the inventory targets established in the FCR-22 order though there were many months during the first half of the historic period that the

Company went well above the upper target limit. The following figure shows the average daily cumulative inventory of coal at plants Bowen, Wansley, and Scherer.

BEGIN TRADE SECRET

Figure 5



END TRADE SECRET

While the Company exceeded the upper inventory target during the first half of the historic period, it managed its inventory levels more closely within its inventory target limits over the second half, during which time the Hammond, Kraft, and McIntosh coal fired units were all retired.[12]

Q. WERE ANY COAL UNITS OPERATED OUT OF ECONOMIC DISPATCH IN ORDER TO MANAGE FUEL INVENTORIES?

A. No, the Company did make decisions to burn down its inventory at retiring plants and it considered those to be economic dispatch decisions. The Company decided it would be

[12] All of those units were retired by the end of July 2019.

more economic to burn the remaining inventory at the coal units rather than transporting the coal elsewhere such as a landfill, which according to the Company would have cost more than dispatching the coal units and consuming the coal.[13]

Coal Procurement

Q. PLEASE DISCUSS YOUR INVESTIGATION OF THE COMPANY'S COAL PROCUREMENT ACTIVITIES IN THIS FCR.

A. Staff's investigated the Company's coal procurement practices following the same approach as in prior FCR proceedings, which included reviewing the Company's Buy Books, reviewing MFRs (3, 6, 7, 8 and 9), and requesting additional discovery.

Q. WHAT INFORMATION IS CONTAINED IN THE BUY BOOKS?

A. The Buy Books contain documentation concerning the procurement of coal typically based on the plants served by specific railroads, such as Norfolk Southern ("NS") or CSX. Typically, each Buy Book includes the following information:

- Reason for procuring coal
- Bid solicitation documentation
- Bids received and analysis of the bids
- Copies of communication with suppliers
- Email confirmation and letter confirmation of purchase agreements
- Contract documentation
- Analyses
- Purchase orders

Q. DID STAFF IDENTIFY ANY CONCERNS?

A. Yes. One issue concerned the bankruptcy of one of the Company's coal suppliers,

[13]MFRH-3.1.

[redacted] (formerly known as [redacted]). Because of the bankruptcy, the Company had to seek an alternative source to supply its coal requirements, and it decided to increase one of its coal solicitations for delivery over the period of July – Oct 2019. Staff's concern was whether the Company's coal procurement costs had increased as a result. Based on its review of discovery responses, Staff ultimately was satisfied that the Company's costs increased by just a small amount with virtually no impact to the ratepayers.

Staff also identified one force majeure event issued by a coal supplier to Georgia Power during the historic period. Burlington Northern and Santa Fe ("BSNF") declared a force majeure event on March 26, 2019 due to record flooding in portions of South Dakota, Iowa, Nebraska, and Missouri.[14] Ultimately, transportation service was restored in a timely manner and both Companies were able to perform in accordance with the contract. The Company also issued several force majeure notices in 2017 regarding a forced outage at Plant Bowen Unit 2.[15] This outage, which occurred between July 13 and October 29, 2017, was caused by a transformer fire and will be discussed in more detail below. Because of the outage, Georgia Power had to issue force majeure notices to several suppliers. However, after the Bowen 2 unit was restored in October of that year, all deliveries subject to the event were made up that same year at the contracted prices.[16] Based on its investigation, Staff was satisfied with the outcome.

Q. WERE THERE ANY CONTRACT NEGOTIATIONS OR LITIGATION ACTIVITIES WITH ANY TRANSPORTATION SUPPLIERS DURING THE

[14] MFRH-8.1
[15] MRH-7.1 and MFRH-7.2
[16] See the Company's response to STF-3-23

HISTORIC PERIOD?

A. No, the Company did not identify any litigation activities that occurred during the historic period. However, the Company did file a complaint under the federal Sherman Act (antitrust law) against the four major U.S. railroads in the United States District Court for the District of Columbia on October 2, 2019. The complaint was made regarding additional transportation surcharges not connected to the cost of fuel or mileage that occurred between 2003 and 2008. This suit may lead to savings for ratepayers, and Staff recommends the Company inform the Commission if any of these benefits have materialized at the time of the FCR-26 filing.

<u>Generation Units</u>

Q. DID STAFF REVIEW THE PRUDENCE OF GEORGIA POWER'S FOSSIL PLANT OUTAGES?

A. Yes, we reviewed fossil unit outages and Dr. Jacobs reviewed nuclear unit outages. As part of our review, we examined unit outage information provided with the Company's filing in MFRH 4.2, which included outage dates and durations, lost energy, NERC cause codes and a brief description of each event. This information provided details regarding planned, forced, and maintenance outages. The Company also included a table of unplanned fossil unit outages and derations that lasted longer than 7 days, which we focused on. We also reviewed select Root Cause Analyses ("RCAs")[17] developed by the Company, which provide a more thorough explanation of the outages based on information

[17] In some cases, the Company referred to Root Cause Analyses as Corrective Action Reports.

the Company gathered from the personnel directly involved in the outage. The RCA includes a determination of the cause(s) of the outage, and a description of the actions that were taken to bring the plant back online.

Q. WHAT DID YOU FOCUS ON IN YOUR ANALYSIS?

A. We focused closely on outages that lasted more than 7 days, and outages that resulted from errors, including operator, maintenance personnel, contractor, operating procedure, maintenance procedure, contractor procedure, and staff procedural errors, which were designated using the NERC cause codes 9900, 9910, 9920, 9930, 9940, 9950, and 9960 respectively.

Q. PLEASE DISCUSS YOUR FINDINGS.

A. Based on the Company's reports there was only one significant outage that was caused by operator error, and five others that resulted in considerable generation losses and/or significant replacement power costs that we determined to be of interest. Staff requested additional information on some of these, which the Company provided in response to STF-1-31, and ultimately, Staff focused on three outages. The first outage was a permanent deration at Hammond 4 that occurred in January of 2018. The second outage was the most significant in terms of generation loss that occurred at Bowen 2 beginning in March of 2018. The third outage also occurred at Bowen 2, but occurred in July 2017, and it was the one that was caused by operator error.

Q. WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO THESE OUTAGES?

A. The Hammond 4 outage occurred in January 2018 and was caused by the failure of bolts attached to a fan assembly that harmed the fan and caused the outage of the unit. After reviewing the information provided by the Company Staff concluded this outage was not the result of imprudence.

The Bowen 2 outage that occurred in March of 2018 was due to an electrical fault caused by a breakdown of insulation at the connection point of the unit's step-up transformer to the generator. The fault occurred at the time the generating unit was starting-up. Given the circumstance of this outage, breakdown of the insulation, we decided this outage was not an issue.

The Bowen 2 outage that occurred in July of 2017 was due to operator error, according to the Company's records. Specifically, the responsible plant operators did not ensure that critical transformer cooling equipment was turned on at the time the Bowen 2 unit was being started up,[18] which caused the transformer to overheat and explode. This then led to fire breaking out in the transformer yard, and ultimately resulted in significant damage to substation equipment. The Company estimated that the outage led to a loss of [redacted] MWh of generation that otherwise would have been produced at Bowen 2, and resulted in $1.53 million dollars in replacement power costs. Staff concluded additional investigation of this outage was warranted, which Staff conducted.

Q. HOW DID STAFF INVESTIGATE THE JULY 2017 BOWEN 2 OUTAGE?

A. Staff investigated the Company's responses to discovery requests in Sets 1 and 3, and by reviewing the Corrective Action Report ("CAR") supplied in MRFH-4.2. The Company's CAR stated, "[redacted]"[19] The CAR concluded that there was a failure on the part of plant personnel to turn

[18] The Company states it never operates the transformer without the critical cooling equipment turned on. (STF-3-1n)

[19] Corrective Action Report, 270528 – U2 GSU Failure, July 13, 2017, provided in MFRH-4.2, Attachment MFRH-4.2-10A TS.pdf, at pg. 3.

the [redacted] on and that led to a fire damaging transformer equipment, leading to the 107 day outage.

Q. SHOULD CUSTOMERS BE RESPONSIBLE FOR THE REPLACEMENT POWER COSTS RESULTING FROM THE FIRE OUTAGE AT BOWEN 2 IN JULY 2017?

A. No. After a thorough examination of the circumstances of the outage, as discussed below, and Staff concludes that too many errors occurred that could have and should have been avoided. These errors include the fact that multiple plant personnel improperly signed off on paperwork indicating that action had been taken to turn [redacted], which in fact was never done, plant personnel did not make proper rounds to perform visual inspections, person-to-person communication was inadequate, [redacted] were improperly recognized, the responsible plant operators were not aware of the [redacted] that would have activated the [redacted].[20] Based on our review, the outage was clearly imprudent, and customers should not be held responsible to pay for the Bowen 2 outage replacement power costs.

Q. PLEASE PROVIDE ADDITIONAL DETAILS ABOUT WHAT CAUSED THE OUTAGE AND HOW OPERATOR ERROR OCCURRED?

A. Prior to the incident, the unit was offline due to another outage and was scheduled to restart on Saturday July 8, 2017. The main [redacted] and [redacted] were turned off while the unit was offline. The unit was released to be re-started at around 10 PM Wednesday July 12. Start-up procedures were violated by the fact that operators signed off on start-up checklists, yet the proper procedures were not followed. In other words, the

[20] STF-3-1.

checklists indicated the [redacted] was turned on, yet it never was. As a result, overheating occurred, "[redacted]".[21] Within 16 hours of the restart, the [redacted] overheated and exploded, and [redacted] was sprayed out into the [redacted] and a fire broke out. The fire was discussed in the CAR as follows:[22]

[redacted]

The CAR stated that the cause was due to the multiple operator performance failures, and it indicated that process related issues were also discovered. The report stated, "[redacted]." Seventeen enhancement actions were identified during the investigation and mentioned in the CAR covering Operator Performance improvements and other issues.

Q. IN YOUR VIEW, WAS GPC AT FAULT IN THIS INCIDENT?

[21] CAR report at page 3, MFRH-4.2.
[22] Id at pg. 5.

A. Yes. While an occasional operator error is expected to occur from time to time, in this case, numerous errors by multiple individuals that led to this significant outage. The Company's CAR noted the following were the apparent causes of the outage:[23]

1. [redacted],
2. [redacted],
3. [redacted],
4. [redacted],
5. [redacted],
6. [redacted].

Q. DO YOU BELIEVE MULTIPLE OPERATOR ERRORS IN THIS SITUATION SHOULD BE OVERLOOKED AND THAT CUSTOMERS SHOULD BE RESPONSIBLE FOR THE REPLACEMENT POWER COSTS?

A. No. Checklists were signed off on stating things that were not true. The CAR indicates that the "[redacted]" was signed off and it "[redacted]"[24] This was not done, despite the checklist indicating it was. In fact, the CAR indicates that operators working on the day shift of July 12th, the night shift of July 12th, and the Day shift of July 13th all inadequately completed three separate checklists which could have helped avoid the

[23] Id at pg. 7.
[24] Id. at pg. 3.

incident.[25] Also, the report indicates that normally the [redacted] Operator ("[redacted]O") makes rounds to check the [redacted], however, the report stated, "[redacted]"

Q. ARE THERE OTHER CONTRIBUTING FACTORS THAT LED STAFF TO CONCLUDE THAT THIS OUTAGE SHOULD NOT OVERLOOKED.

A. Yes. There were other indicators that the operators were aware of, or reasonably should have been aware of that could have been used to prevent this catastrophic outage. Item 6 in the list above from the CAR states, "[redacted]". The CAR indicates that Southern Company determined that at least [redacted] were sent to the Control Room warning that [redacted] were occurring within the [redacted] over the 16 hour period that the Bowen 2 unit operated before its [redacted] exploded, without any action being taken by the operators. The CAR indicates that [redacted] were acknowledged by the operators (pg. 13 of CAR), but for some reason the investigators were not able to determine what the acknowledgement meant to the operators at the time of the event. It appears unlikely that the severity of the [redacted] were fully understood by the operators that saw them as the CAR stated, "[redacted]"

Q. DID THE CAR INDICATE THAT OPERATORS AT THE BOWEN 2 PLANT

[25] Id. at pg. 6.

WERE PROPERLY TRAINED AND PROCEDURES WERE IN PLACE TO ALLOW OPERATORS TO PROPERLY STARTUP THE UNIT?

A. Yes, it did. As part of its investigation, the Company investigated whether proper procedures were in place and whether operators were properly trained. The Company concluded that proper procedures were in place and training was performed, yet the procedures were not followed. With regard to procedures, page 20 of the CAR Report states, "[redacted]"

The Company also stated in the report that the plant procedures and training contained "[redacted]"

Q. WHAT INSIGHT DOES THE REPORT PROVIDE AS TO WHY THE OPERATORS DID NOT STARTUP THE COOLING SYSTEM?

A. The CAR indicates training and procedures were in place instructing the operator to "[redacted]" yet those instructions seemed to have been overlooked, forgotten, or ignored. Additionally, another operator, the [redacted] Operator, did not make rounds during the day shift on July 13, during the critical hours that the [redacted] should have been in operation. Regardless of the fact that training and procedures were in place, the procedures were not followed. The outage event involved multiple plant operators that did not recognize the [redacted] was turned off and by signature indicated that it was on, and this process occurred over three shifts.[26] Had the procedures been followed, the explosion could have been avoided.

Q. IS THE COMPANY'S DERIVATION OF THE REPLACEMENT POWER COST DUE TO THE BOWEN 2017 OUTAGE REASONABLE?

A. Yes. To derive the replacement power cost of an outage, the Company uses an hourly marginal-cost spreadsheet model, in which the operating cost of the unit that failed are compared to the Southern Company Pool Interchange Rate ("PIR"), which is assumed to be the incremental cost that would be incurred if additional generation were needed, in an hour. The difference in the two costs are summed over all hours, and the result is the replacement power cost estimate. Staff reviewed the calculation and accepts the result.

Q. WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO THE PLANT BOWEN OUTAGE IN 2017?

A. Given the number of errors that occurred by multiple individuals, including the fact that nobody turned on the important transformer cooling pumps and fans, that checklists were completed that were not true, that rounds were not completely performed, and that alarms went off that were acknowledged but not understood, or possibly were just ignored, it is Staff's opinion the outage is the result clear imprudence by the Company. Staff recommends that the Commission make a disallowance of the replacement costs that resulted from the outage. Staff recommends that the $1.53 million in replacement power cost resulting from this outage be disallowed.[27] This disallowance should be refunded to the ratepayers through an adjustment in the over/under-recovered fuel balance in June

[26] STF-3-1-i indicated that as a result of the outage event, 2 operators were terminated, two were placed on discipline, and one retired in lieu of being placed on discipline.
[27] See MFRH-4.2.

2020.

Prudence Standard

Q. PLEASE DISCUSS THE PRUDENCE STANDARD YOU CONSIDERED AS YOU EVALUATED THE PRUDENCE OF THE BOWEN 2 OUTAGE.

A. The Commission first adopted its current prudence standard in Docket No. 6739-U involving the Rocky Mountain Pumped Storage project. The "Rocky Mountain" standard is as follows:

> A decision must not be judged as correct or incorrect in the light of perfect hindsight. Rather, a decision must be judged as to whether it was reasonable given the facts and circumstances which were known or which reasonably should have been known at the time the decision was made. In applying this standard, it must be recognized that in any decision making process there may exist a range of choices, any or all of which could have been adopted by reasonable management in good faith and under the same set of circumstances. If the Company has made a decision which falls within that "zone of reasonableness," that decision must be found to have been prudent, irrespective of whether others may have selected another alternative, and irrespective of whether in hindsight another decision may now appear in hindsight to have been a more correct decision.[28]

This standard is essentially a "reasonable man standard" in that the utility's actions or decisions are compared to the reasonable actions or decisions of a qualified and experienced utility manager or operator given what was known, or reasonably should have been known, at the time action was taken or the decision was made without the benefit of hindsight.

Q. DOES THE FCR STATUTE, O.C.G.A. §46-2-26, PROVIDE ANY ADDITIONAL REQUIREMENTS CONCERNING PRUDENCE?

[28] Order issued January 15, 1998 in Docket No. 6739-U, page 6 of 30.

A. O.C.G.A.§46-2-26(h) requires that "*The commission shall disallow and make appropriate adjustment for any reported fuel cost that is the result of illegal or clearly imprudent conduct on the part of the utility*."

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF WHAT IS MEANT BY "CLEARLY IMPRUDENT."

A. We have been advised by Staff counsel that witnesses must support their conclusions about the "clearly imprudent" conduct, and the Commission will ultimately make the determination of whether the conduct should be considered clearly imprudent using whatever standards the Commission deems appropriate. For example, the Commission could apply such commonly accepted standards as "clear and convincing", "preponderance of the evidence" or "beyond a reasonable doubt" in determining whether imprudent conduct was also clearly imprudent.

While we understand that the role of a witness is to support a conclusion that conduct was imprudent, allowing the Commission to apply whatever standard it deems appropriate, the Commission may desire that a witness recommend a standard to be applied by the Commission when reviewing acts of imprudence. In our opinion, in determining whether particular imprudent conduct is also clearly imprudent, the Commission should apply a "clear and convincing evidence" level of scrutiny. The "clear and convincing evidence" test is a medium level of scrutiny which is a more rigorous standard to meet than the preponderance of the evidence standard, but a less rigorous standard to meet than providing evidence beyond a reasonable doubt, which is generally reserved for criminal cases. In order to meet the standard and prove something by clear and convincing evidence, a party must prove that it is substantially more likely than not to be true. It is Staff's opinion that given the multiple errors by multiple individuals that there is "clear and convincing evidence" that this outage was the result of clearly imprudent actions by the Company.

Reasonableness Standard

Q. DISCUSS THE REASONABLENESS STANDARD IN THE CONTEXT OF THIS FCR CASE.

A. Regulators frequently make rate case adjustments to provide for "just and reasonable rates." Such adjustments are not necessarily related to imprudence. In a general rate case setting, typical examples might include disallowance of certain kinds of lobbying expenses, certain advertising costs, or payments to affiliated companies. In the context of this FCR request, there are also important issues related to establishment of just and reasonable rates, such as the timing of when costs are incurred and charging those costs to the customers that caused those costs to be incurred.

Q. IS THE "REASONABLENESS STANDARD" RECOGNIZED BY STATUTE IN GEORGIA?

A. Certainly. O.C.G.A § 46-2-26 (d) implicitly adopts this standard by requiring that:

> "At any hearing conducted pursuant to this Code section, the burden of proof to show *that an increased rate*, based on fluctuations in fuel costs, *is just and reasonable* shall be upon the utility." (italics added)

Staff believes that the Bowen 2 outage is clearly imprudent and furthermore, Staff also believes that it would be unreasonable for ratepayers to be required to pay the costs of the outage given the number of errors that occurred and the facts the Company knew or reasonably should have known that would have avoided the outage.

Planned Outages

Q. DID YOU ALSO REVIEW GEORGIA POWER'S FCR-24 HISTORIC PERIOD FOSSIL UNIT PLANNED OUTAGES?

A. Yes, and we did not find any issues with those outages. Planned outages are scheduled for a time when units are less needed (shoulder months, weekends) in order to perform required maintenance on the units.[29] Our investigation included reviewing planned outages that occurred during the historic period of FCR-25 and compared those to prior FCR proceedings (FCR-20 through FCR-25).

Q. WHAT WERE THE RESULTS OF YOUR COMPARISON?

A. Our planned outage evaluation focused on the number of major planned outages, greater than 500,000 MWH that occurred during the period, and we compared the calculated average to the same calculation from prior FCR proceedings.

Table 5

AVERAGE LOST GENERATION COMPARISON

FCR-20 THROUGH FCR-25

	No. of Months in FCR Period	No. of Outages > 500,000 MWH	Avg. Lost Gen. Per Outage (MWH)
FCR-20	12	[redacted]	682,505
FCR-21	21	[redacted]	749,214
FCR-22	15	[redacted]	961,869
FCR-23	13	[redacted]	1,018,788
FCR-24	41	[redacted]	942,742
FCR-25	53	[redacted]	989,232

[29] In contrast unplanned outages are the result of an unexpected event(s) that often require units to be remove from service immediately.

Q. PLEASE DESCRIBE THE RESULTS SHOWN IN THE TABLE.

A. The second column contains the total number of planned outages that resulted in lost generation greater than 500,000 MWH. The number of planned outages has increased from [redacted] every 12 months in FCR-20 to [redacted] in FCR-25. The average generation lost per planned outage has been stable over the last four FCRs. Aging generating units in the fleet could require more planned outages with more extensive maintenance to be done.

<u>Carrying Costs</u>

Q. DID THE COMMISSION PREVIOUSLY AUTHORIZE THE COMPANY TO RECOVER CARRYING COSTS ON UNDER-RECOVERED FUEL COST BALANCES?

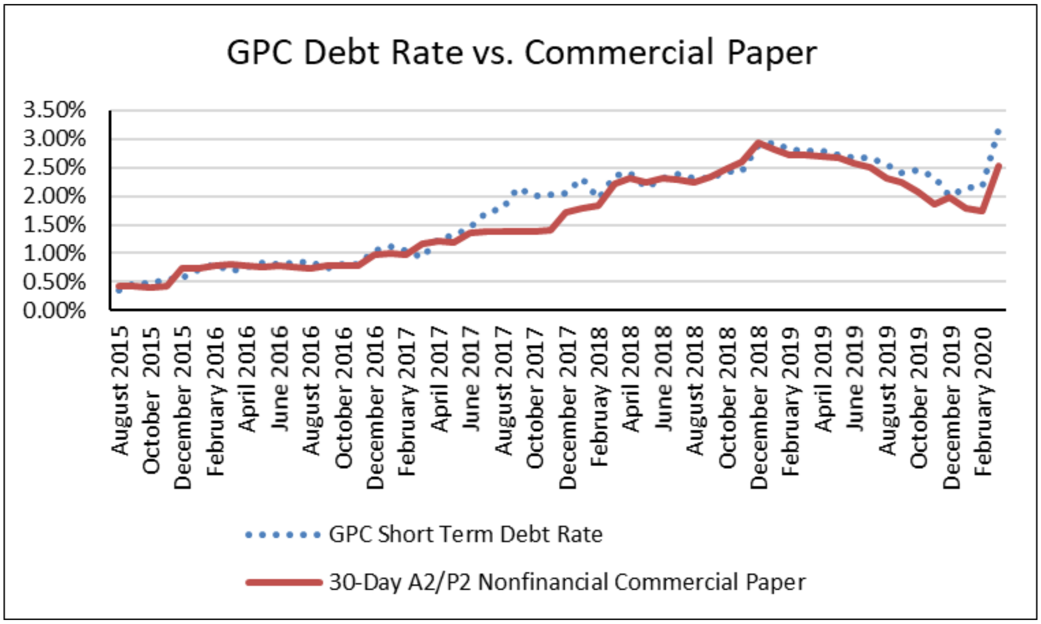
A. Yes. In Docket No. 17066 the Commission approved the accrual of carrying costs, calculated with Georgia Power's short-term debt rate for unrecovered fuel costs above the first $15.0 million.

Q. DID YOU REVIEW THE COMPANY'S CARRYING COST CALCULATION?

A. Yes. MFRH-15 shows the computation of carrying costs based on the short-term debt rates during the historic period. The short term debt rate was relatively low early in the historical period beginning at 0.36%, and rose significantly after that, averaging 1.71% over the entire historic period. While there is significant growth in the short term debt rate over time, the growth is mostly consistent with the 30-day A2/P2 Nonfinancial Commercial

Paper interest rate, as seen in the chart below.[30] When the cumulative fuel balance is over-recovered, customers are credited carrying costs, and when the balance is under-recovered customers are charged carrying costs. Overall, during the historic period, net carrying costs amounted to $2.7 million dollars that customers paid Georgia Power based on the Company's short term debt rate. Had carrying costs been computed based on the 30-day A2/P2 Nonfinancial Commercial Paper interest rate, customers would have been charged $2.5 million.

Figure 6



[30] Federal Reserve Bank of St. Louis, Federal Reserve Economic Data, 30-Day A2/P2 Non-Financial Commercial Paper Interest Rate, https://fred.stlouisfed.org.

V. PROJECTED TEST PERIOD REVIEW

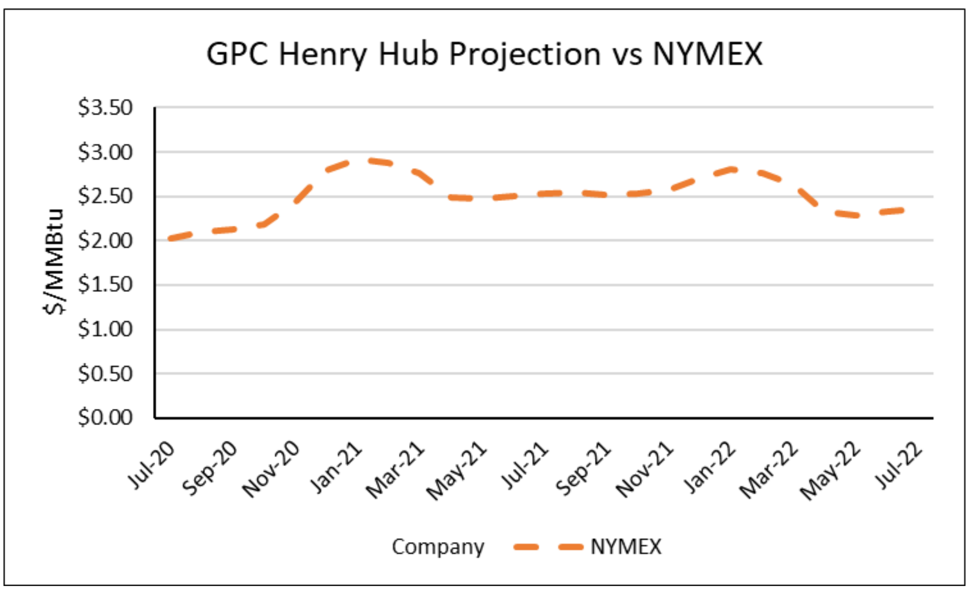
<u>Fuel Price Forecast Assumptions</u>

Q. HAVE YOU EVALUATED GEORGIA POWER'S FCR-25 NATURAL GAS PRICE FORECAST?

A. Yes. Georgia Power developed its natural gas forecast for the forecast test period based on a 20-day moving average of NYMEX Henry Hub futures prices derived over the period of July 30, 2019 to August 26, 2019. Figure 7 compares Georgia Power's Henry Hub natural gas price forecast to more recent NYMEX Henry Hub futures prices that were published on April 14th, 2020.

BEGIN TRADE SECRET

Figure 7



END TRADE SECRET

Staff believes the Company's forecast is within an acceptable range of the current NYMEX futures, and follows a similar trend, though it does diverge more towards the end of the forecast period.

Fuel Projection Updates

Q. STAFF RECOMMENDED THE COMPANY PROVIDE UPDATED PROJECTIONS ON JUNE 30TH AND DECEMBER 31ST EACH YEAR OF MONTHLY FUEL REVENUES AND EXPENSES, AND MONTHLY OVER OR UNDER COLLECTIONS AND PROJECTED FUEL BALANCES THROUGH MAY 31, 2023. DOES STAFF BELIEVE THIS RECOMMENDATION WOULD BE BURDENSOME?

A. No. Staff's understanding is the Company prepares its annual budgets with updated assumptions of load, sales and cost each fall for the following calendar years. Therefore, the Company would have all the necessary information to provide the December 31 update. Regarding the June 30 update, while Staff would prefer a complete update of all assumptions, Staff would not object if the Company were to only update its natural gas forecast and retain all other assumptions as included in the prior fall update.

Natural Gas Price Hedging Program

Q. WHAT IS THE PURPOSE THE COMPANY'S NATURAL GAS HEDGING PROGRAM ACCORDING TO THE COMPANY?

A. According to the Company the "current hedging program is not intended to beat the market, but instead to benefit customers by *providing greater cost stability*."[31]

Q. WHAT IS STAFF'S OPINION OF COST STABILITY?

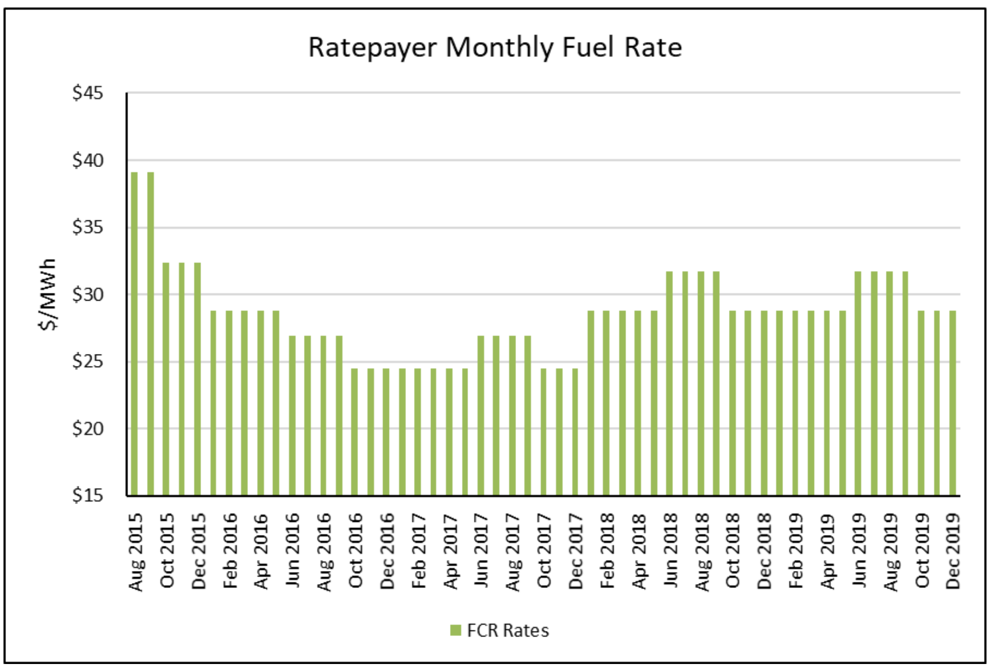
[31] Georgia Power Company Adams direct testimony. Page 8 Lines 15 – 16.

A. We believe cost stability for customers is an important consideration in setting regulatory policy.

Q. HOW DOES THIS COMMISSION PROVIDE FUEL COST STABILITY FOR CUSTOMERS?

A. The Commission sets fixed fuel rates that do not change from month to month. Fuel rates change on June 1 when summer rates go into effect and October 1 when winter rates go into effect. There may be other changes in fuel rates from revisions in FCR rates from a FCR proceeding and implementation of Interim Fuel Rider. Generally, fuel rates remain fairly stable throughout the year between FCR proceedings as shown in the graph below.

Figure 8



Q. IS THERE A COST TO CUSTOMERS FROM USING FIXED FUEL RATES TO PROVIDE FUEL COST STABILITY?

A. Yes. Generally, fixed rates will not collect the exact amount of revenues to offset the

Company's fuel expense in a given month. The Company will either over collect or under collect for a given month. The cumulative monthly over or under collections represent the fuel balance. The Commission allows the Company to recover financing or carrying cost on the fuel balance.

Q. WHAT HAS BEEN THE FINANCING COST ON THE FUEL BALANCE COLLECTED FROM CUSTOMERS?

A. The financing cost has generally been quite modest as shown in the table below.

Table 6

Year	Fuel Balance Financing Cost ($ million)
2005	$10.4
2006	$27.3
2007	$26.3
2008	$11.7
2009	$2.3
2010	$0.9
2011	$0.4
2012	-$0.1
2013	-$0.4
2014	$0.2
2015	-$0.5
2016	-$0.7
2017	$0.4
2018	$2.2
2019	$0.8
Total	$81

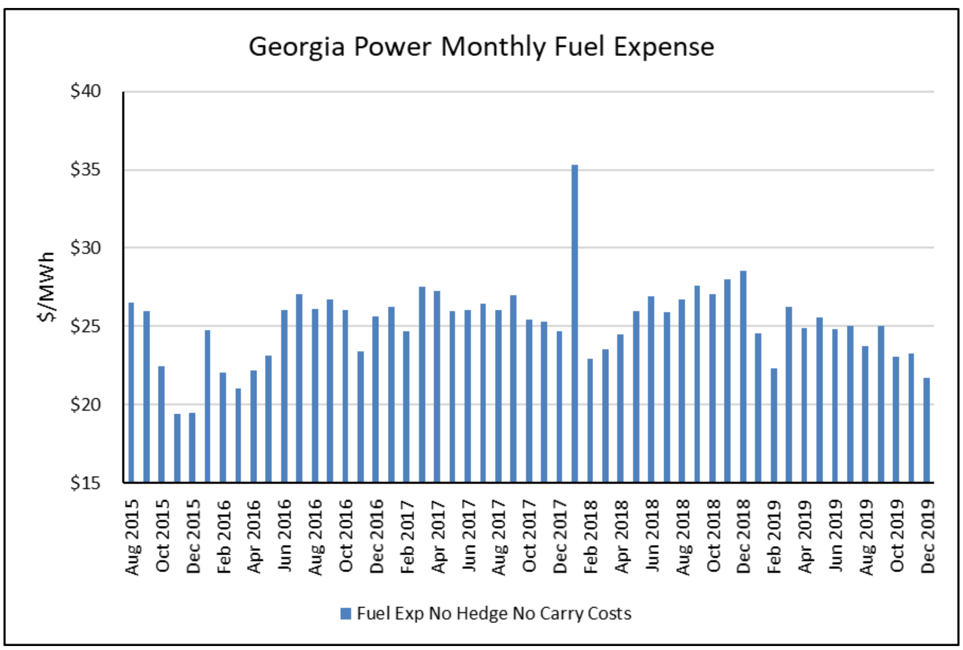
Q. GIVEN THE COST STABILITY PROVIDED BY FIXED FUEL RATES AND THE MODEST FINANCING COST INCURRED, IS A NATURAL GAS HEDGING PROGRAM NECESSARY TO PROVIDE COST STABILITY FOR CUSTOMERS?

A. No. The Company's natural gas hedging program has provided very little cost stability and has cost customers considerably over the past 15 years. Fixed fuel rates are by far a more efficient approach to providing fuel cost stability to customers. This is why Staff is recommending the Company's natural gas price hedging program be discontinued.

Q. YOU STATED THAT THE COMPANY'S NATURAL GAS PRICE HEDGING PROGRAM HAS PROVIDED VERY LITTLE COST STABILITY. PLEASE PROVIDE AN EXAMPLE.

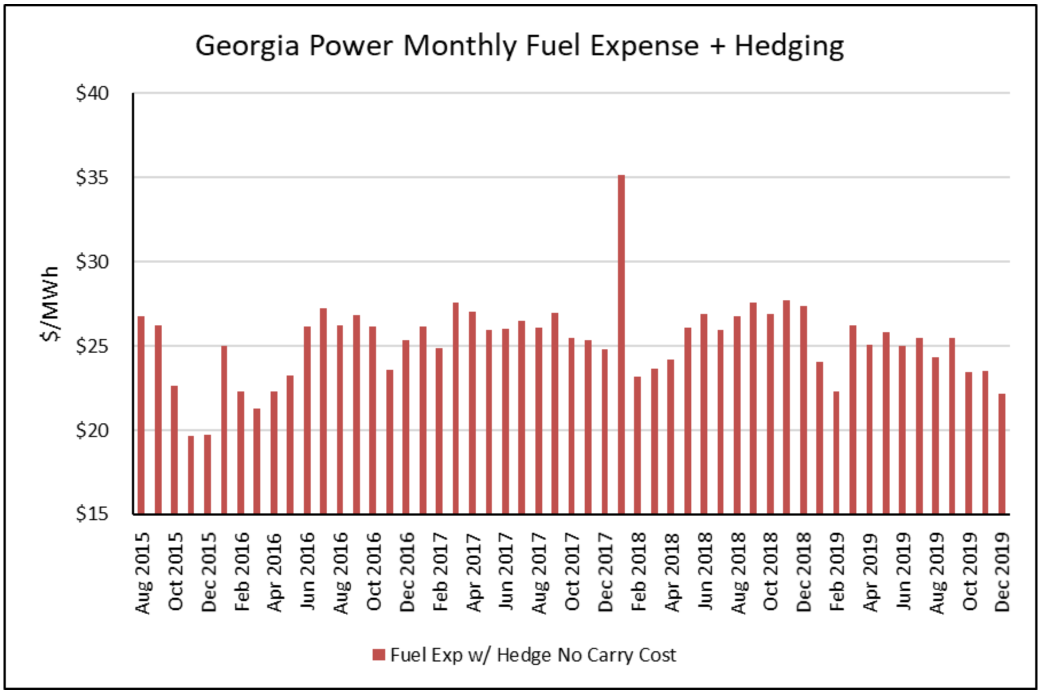
A. The graph below shows the monthly fuel cost being incurred by the Company during August 2015 through December 2019.

Figure 9



The graph shows the variability or change from month to month in the Company fuel expense. There is a fair amount of the change from month to month. The values in the graph include only fuel expense and do not include the impact of the natural gas price hedging program. The next graph shows the Company's monthly fuel expense with hedging and the variation from month to month.

Figure 10



The graphs are essentially identical. The hedging program had a de minimis impact on fuel cost variability during the historical period. Even in the month in which the fuel prices spiked (January 2018), the Company's hedging activity made little noticeable impact.

Q. WHAT WAS COST OF THE NATURAL GAS PRICE HEDGING PROGRAM DURING THIS PERIOD.

A. The cost was $31 million.

Q. PLEASE SUMMARIZE THE NATURAL GAS PRICE HEDGING PROGRAM'S PERFORMANCE DURING THE HISTORICAL PERIOD OF AUGUST 2015 – DECEMBER 2019.

A. The hedging program provided very little fuel cost stability at a cost of $31 million. In contrast, fixed fuel rates remove much the variation in fuel expenses and provided significant cost stability at a very modest cost of less than $3 million in carrying cost.

Q. HISTORICALLY HAS THE COST OF FIXED FUEL RATES (CARRYING CHARGE ON FUEL BALANCE) BEEN SIGNIFICANTLY LESS THAN THE COST OF THE NATURAL GAS PRICE HEDGING PROGRAM.

A. Yes. The table below demonstrates this.

Table 7

Year	Hedging Program Impact ($ million)	Fuel Balance Financing Cost ($ million)
2005	-$48	$10.4
2006	$66	$27.3
2007	$67	$26.3
2008	-$6	$11.7
2009	$184	$2.3
2010	$90	$0.9
2011	$106	$0.4
2012	$86	-$0.1
2013	$33	-$0.4
2014	$12	$0.2
2015	$26	$0.2
2016	$10	-$0.7
2017	$1	$0.4
2018	-$11	$2.2
2019	$21	$0.8
Total	$638	$81

Q. PLEASE SUMMARIZE THE STAFF'S RECOMMENDATION REGARDING THE COMPANY'S NATURAL GAS HEDGING PROGRAM.

A. The Company's hedging program has been ineffective in stabilizing fuel cost and has substantially increased customer cost. The hedging program provides very little value for customers. In contrast fixed fuel rates do provide significant stability at very modest cost and provide value to customers. For these reasons, the Company's natural gas price hedging program should be discontinued, and the Commission should continue to rely on fixed fuel rates to provide cost stability to customers at much lower cost.

<u>Interim Fuel Rider</u>

Q. STAFF HAS RECOMMENDED REVISING THE TRIGGER TO IMPLEMENT THE INTERIM FUEL RIDER FOR THE FUEL BALANCE TO EXCEED $150 MILLION FOR THREE CONSECUTIVE MONTHS. WHAT WOULD BE THE BENEFIT OF A REVISED INTERIM FUEL RIDER TRIGGER.

A. This revision would mitigate the impact of temporary factors that could inflate the fuel balance and provide a more structured and timely approach to addressing large fuel balances between FCR cases. It would also allow the Commission to mitigate large fuel balances sooner with a smaller adjustment to FCR rates and more accurately assign cost to those customers that cause the cost.

Q. WOULD THE REVISED TRIGGER RESULT IN THE IFR BEING IMPLEMENTED FREQUENTLY.

A. No. The revised trigger proposed by Staff of the fuel balance exceeding $150 million for three consecutive months occurred two times during the historical period of August 2015 through December 2019. The current trigger of the fuel balance exceeding $200 million in a single month occurred one time during the historical period.

Vogtle 3 and 4 Lost Fuel Savings

Q. DO YOU HAVE ANY CONCERNS ABOUT THE LOST FUEL SAVINGS THAT HAVE OCCURRED AS A RESULT OF THE DELAYS IN THE VOGTLE 3 AND 4 PROJECT?

A. Yes, Vogtle Units 3 and 4 have now been delayed far past their original commercial operation dates of April 2016 and April 2017, respectively in the Company's certification filing. During the certification hearing, the Company told the Commission that even an 18-month delay would result in a substantial "loss of fuel cost savings on the order of 400 to 700 million dollars a year for customers."[32] Currently Units 3 and 4 are expected to be delayed 68 months and ratepayers have been paying for additional replacement fuel costs since April 2016.

Staff believes that an adjustment for these replacement fuel costs should be made, however, that issue will be considered at the time that the Vogtle 3 and 4 costs undergo a prudency review. Paragraph 7 of the Stipulation in the 8th Vogtle Construction Monitoring ("VCM") proceeding states:

> In order to preserve issues that could be raised by Staff in VCM 8 or in subsequent VCM periods, the Company agrees that, if the Commission subsequently makes a finding of fraud, concealment, failure to disclose a material fact, imprudence, or criminal misconduct in the Vogtle construction, the Commission has the authority to disallow associated financing and replacement fuel costs. In the event that such financing costs or replacement fuel costs have already been recovered by the Company from customers, the Company shall credit such costs back to the benefit of customers in a manner to be determined by the Commission.

[32] Georgia Power Vogtle Certification Proceeding, Docket No. 27800, Transcript, Page 1787, February 9, 2009.

The Order in the 17th Vogtle Construction Monitoring ("VCM") proceeding provides that the prudency review proceeding will be held when the plant goes into Commercial Operation.[33]

In the 12th VCM proceeding, the Commission ordered that the Company to develop and implement a mechanism to track replacement fuel cost that occurs as a result of the delay and report the mechanism to the Commission by April 1, 2016 and in all future VCM Reports. In its most recent VCM filing, VCM 22, the Company reports that there have been $474 million dollars in replacement energy costs due to the delay of Vogtle 3 and 4.[34] Staff reserves our right to address these costs in a later proceeding.

<u>Other Issues</u>

Q. DID YOU INVESTIGATE ANY OTHER ISSUES?

A. Yes, Staff also examined opportunity sales revenues and senior citizens discounts. In the case of opportunity sales revenues, Staff examined the level of profits shared between the Company and customers. Currently, the Company is entitled to keep 25% of the profits.[35] During the FCR-25 historical period, the total profits the Company achieved from making these sales was $16.7 million, with $12.5 million going to ratepayers, and $4.2 million to the Company. This was about the same amount of profit the Company made in FCR-24 from these sales, and therefore, Staff does not oppose continuing the sharing mechanism at this time.

[33] See page 2 of the Order on the Seventeenth Semi-Annual Vogtle Construction Monitoring Report, filed Jan 11, 2018 in Dk. No. 29849.
[34] See Table 1.2 in the Twenty-second Semi-annual Construction Monitoring Report for Plant Vogtle Units 3 and 4, filed Feb 19, 2020 in Dk. No. 29848.
[35] See the Commission's 1989 Order in Docket 3840.

Concerning the Senior Citizens discount, which the Company has been offering to qualifying seniors for some time, Staff reviewed the number of low income senior citizens that receive the discount over the historic period, and the number expected to receive it over the projected period. The Company reported that the number of customers that received the discount was fairly level and ranged from about 88,500 to 90,000 during the historic period, and about the same number will receive it in the projected period. Staff is satisfied with the Company's outreach to customers for this discount.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

IN THE MATTER OF: GEORGIA POWER COMPANY'S FUEL COST RECOVERY APPLICATION (FCR-25)	**DOCKET NO. 29849**

EXHIBIT

STF-NH-1

Summary of Educational and Professional Experience of Tom J. Newsome

Mr. Newsome received a Bachelor of Chemical Engineering with certificates in Pulp & Paper and Polymers from the Georgia Institute of Technology in June 1986. In 1994, Mr. Newsome passed both required examinations and received a professional engineering license (PE) from the State of North Carolina. Mr. Newsome received a Master of Science in Business Economics and a Master of Science in Finance from Georgia State University in August 1996 and June 1997, respectively. Mr. Newsome is the recipient of the George J. Malanos Graduate Award for Academic Excellence for completing the finance program with a 4.0 grade-point average. In 2003, Mr. Newsome received Chartered Financial Analyst (CFA) designation from the CFA Institute after successfully completing three six-hour examinations on security analysis and portfolio management.

After graduation from Georgia Tech, Mr. Newsome worked as plant/process engineer for Shaw Industries, a carpet manufacturer. In April 1988, Mr. Newsome joined Weatherly, Inc., engineering and construction firm specializing in fertilizer plants, as a process engineer. Mr. Newsome's primary responsibilities were process design and plant start-ups, including start-ups in Korea and India. Mr. Newsome joined Midrex Direction Reduction Corp., an applied research, engineering and construction firm with proprietary iron ore processing plant technology in March 1993 as a process engineer. Mr. Newsome duties were similar to those at Weatherly, including assisting in the start-up of the world's largest Direct Reduction Iron plant in India.

Following graduation from graduate school at Georgia State, Mr. Newsome joined Georgia Gulf Corporation in 1997 as a corporate development analyst. While at Georgia Gulf, Mr. Newsome performed financial analysis and modeling for natural gas purchasing/hedging program, developed a "make-or-buy" model for methanol business, performed financial modeling for an acquisition, and calculated and summarized the financial performance of prior capital investments. In 1999, Mr. Newsome joined FMV Opinions, Inc. as a business valuation analyst and valued private companies for gift and estate tax, transactional and management planning purposes.

Mr. Newsome joined the Georgia Public Service Commission ("Commission") in January 2005 as a Financial Analyst/Economist. Mr. Newsome was promoted to Director of Utility Finance in 2008.

Mr. Newsome has testified in fourteen Georgia Power Company ("Company" or "Georgia Power") proceedings before the Commission. Mr. Newsome's most recent testimony was in Docket 29849 20th/21st Vogtle Construction Monitoring ("VCM") proceeding on Vogtle 3 and 4 economics, costs and impact on ratepayers. Prior to that Mr. Newsome testified in Docket 42310 Georgia Power Company's 2019 Integrated Resource Plan on supply side and certain other issues. Prior to that testimony Mr. Newsome testified in Docket 29849 19th Vogtle Construction Monitoring ("VCM"), 18th VCM and 17th VCM on the economics of continuing Vogtle 3 and 4 construction and provided the Commission policy recommendations to protect ratepayers. Prior to testifying in the 17th VCM Mr. Newsome testified in the 2016 Integrated Resource Plan on the Company's requested to capitalize cost for investigation of new nuclear units. Mr. Newsome's testified in Docket No.

39638 Fuel Cost Recovery (FCR-24) on the Company's natural gas hedging program. In Docket No. 22403, Mr. Newsome addressed Georgia Power Company's natural gas hedging program and in Docket No. 24506 Mr. Newsome testified on the application of AFUDC accounting for calculating financing cost of capital projects. In Docket No. 27800, Certification of Plant Vogtle Expansion, Mr. Newsome addressed the sources, impact and mitigation of financial risk from the construction and operation of new nuclear units at Plant Vogtle. Mr. Newsome testified in Docket No. 29849 concerning Georgia Power's First Semi-annual Construction Monitoring Report on Plant Vogtle expansion. Mr. Newsome evaluated the economic analysis performed by Georgia Power and developed Staff's own independent economic and risk analysis of the Project. In the Second Vogtle Semi-annual hearing, Mr. Newsome testified on the Company's proposal to change how escalation on certain project cost was calculated (Amendment 3). In the Third Vogtle Semiannual hearing and in separate proceeding, Adoption of a Risk Sharing Mechanism, Mr. Newsome testified on Staff's revised risk sharing mechanism for Vogtle 3 & 4. In Docket No. 28945 Fuel Cost Recovery FCR–21, Mr. Newsome testified on seasonal rates. Mr. Newsome also presented cost of equity testimony in Atmos Energy Corporation's Rate Case in Docket No. 30442 and Generic Proceeding to Implement House Bill 168 (small telephone companies) in Docket No. 32235 in 2011 and 2018. Mr. Newsome provided testimony before the Commission in Georgia Power's 2013 Base Rate Case in Docket No. 36989 on the Company's projected cost of debt for 2014 – 2016. Mr. Newsome's primarily responsibility, prior to presenting testimony in these dockets, has been performing analyses of the parties' cost of equity capital positions in Docket Nos. 18638 (Atlanta Gas Light Company 2004/2005 Rate Case), 19758 (Savannah Electric and Power Company 2004 Rate Case), 20298 (Atmos Energy Corporation - Georgia Division 2005 Rate Case), 25060 (Georgia Power Co. 2007 Rate Case) and 27163 (Atmos Energy Corporation - Georgia Division 2008 Rate Case) and developing the Advisory PIA Staff's cost of equity recommendation to the Commission.

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

IN THE MATTER OF: GEORGIA POWER COMPANY'S FUEL COST RECOVERY APPLICATION (FCR-25)	**DOCKET NO. 29849**

EXHIBIT

STF-NH-2

QUALIFICATIONS OF PHILIP HAYET

EDUCATION/CERTIFICATION

M.S., Electrical Engineering, Georgia Institute of Technology, 1980
B.S., Electrical Engineering, Purdue University, 1979
Cooperative Education Certificate, Purdue University, 1979

PROFESSIONAL AFFILIATIONS

National Society of Professional Engineers
Georgia Society of Professional Engineers
Institute of Electrical and Electronic Engineers

EXPERIENCE

Since completing his Master's program, Mr. Hayet worked for fifteen years at Energy Management Associates, now Ventyx, providing consulting services and client service support to electric utility companies for the widely used planning models, PROMOD IV and STRATEGIST. Mr. Hayet had an instrumental role in designing some of the modeling features of those tools including the competitive market modeling logic in STRATEGIST.

In 1995, Mr. Hayet began his own utility consulting firm, Hayet Power Systems Consulting ("HPSC"), and has worked for customers in the United States, and internationally in Australia, Japan, Singapore, Malaysia, the United Kingdom, and Vietnam. Over his more than 30-year career, Mr. Hayet has provided consulting services to Public Utility Commissions, Regional Power Pools, State Energy Offices, Consumer Advocate Offices, Electric Utilities, Global Power Developers, and Industrial Companies. Mr. Hayet's expertise covers a number of areas including utility system planning and operations, RTO analysis, market price forecasting, Integrated Resource Planning, renewable resource evaluation, transmission planning, demand-side analysis, and economic analysis.

In 2000 Mr. Hayet also joined the consulting firm of J. Kennedy & Associates, Inc. ("Kennedy and Associates"). Since joining, Mr. Hayet worked on Kennedy and Associates' projects that required utility resource planning, analysis, and software modeling expertise. Mr. Hayet became a Vice-President and Principal of Kennedy and Associates in 2015.

Mr. Hayet has conducted numerous consulting studies in the areas of RTO Cost/Benefit Analysis, Renewable Resource Evaluation, Renewable Portfolio Standards Evaluation, Electric Market Price Forecasting, Generating Unit Cost/Benefit Analysis, Integrated Resource Planning, Demand-Side Management, Load Forecasting, Rate Case Analysis and Regulatory Support.

2000 to **J. Kennedy and Associates, Inc.**

QUALIFICATIONS OF PHILIP HAYET

Present: **Vice President and Principal**

- Initially began as Director of Consulting, became Vice President and Principal in 2015
- Managed electric related consulting projects.
- Responsible for business development.
- Clients include Staffs of Public Utility Commissions and other State Agencies, State Energy Offices, Global Power Developers, and Industrial Groups, and large energy users.

1996 to Present: **Hayet Power Systems Consulting**
President and Principal

- Managed electric utility related consulting projects
- Clients include Staffs of Public Utility Commissions and other State Agencies, State Energy Offices, Global Power Developers, and Industrial Groups, and large energy users.

1991 to 1996: **EDS Utilities Division, Atlanta, GA (Now Ventyx)**
Lead Consultant, PROSCREEN (Now STRATEGIST) Department

- Managed a client services software team that supported approximately 75 users of the STRATEGIST electric utility strategic planning software.
- Participated in the development of STRATEGIST's competitive market modeling features and the Network Economy Interchange Module
- Provided client management direction and support, and developed new consulting business opportunities.
- Performed system planning consulting studies including integrated resource planning, DSM analysis, marketing profitability studies, optimal reserve margin analyses, etc.
- Based on experience with PROMOD IV, converted numerous PROMOD IV databases to STRATEGIST, and performed benchmark analyses of the two models.

1988 to 1991: **Energy Management Associates (EMA), Atlanta, GA**
Manager, Production Analysis Department

- Served as Project Manager of a database modeling effort to create an integrated utility operations and generation planning database. Database items were automatically fed into PROMOD IV.
- Supervised and directed a staff of five software developers working with a 4GL database programming language.

- Interfaced with clients to determine system software specifications, and provide ongoing client training and support

1980 to 1988: **Energy Management Associates (EMA), Atlanta, GA**
Senior Consultant, PROMOD IV Department

- Provided client service support to EMA's base of over 70 electric utility customers using the PROMOD IV probabilistic production cost simulation software.
- Provided consulting services in a number of areas including generation resource planning, regulatory support, and benchmarking.

QUALIFICATIONS OF PHILIP HAYET

TESTIMONY AND EXPERT WITNESS APPEARANCES

Date	Case	Jurisdict	Party	Utility	Subject
09/98	97-035-01	UT	Utah Committee for Consumer Services	PacifiCorp	Utah jurisdictional Net Power Costs, PacifiCorp Rate Case Proceeding
07/01	01-035-01	UT	Utah Committee for Consumer Services	PacifiCorp	Utah Jurisdictional Net Power costs in General Rate Case
2001	ER00-2854-000	FERC	Louisiana Public Service Commission	Entergy	Proposed System Agreement Modifications
07/02	02-035-002	UT	Utah Committee for Consumer Services	PacifiCorp	Special contract for industrial consumer
2002/ 2003	U-25888	LA	Louisiana Public Service Commission	Entergy	Investigation of retail issues related to the System Agreement
2003	U-27136 Subdocket A	LA	Louisiana Public Service Commission Staff	Entergy	Aging gas steam-fired retirement study
07/03	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy	Rough production cost equalization proceeding
05/04	03-035-14	UT	Utah Committee for Consumer Services	PacifiCorp	Development of a large QF avoided cost methodology
06/04	18687-U 18688-U	GA	Georgia Public Service Commission Staff	Georgia Power and Savannah Electric	2004 Integrated Resource Planning Studies
08/04	ER03-583-000	FERC	Louisiana Public Service Commission	Entergy	Affiliate power purchase agreements
11/04	03-035-19	UT	Utah Committee for Consumer Services	PacifiCorp	Industrial customer’s request for a special economic development tariff
11/04	03-035-38	UT	Utah Committee for Consumer Services	PacifiCorp	Large QF proceeding.
03/05	03-035-14	UT	Utah Committee	PacifiCorp	Concerning PacifiCorp’s Schedule 38

QUALIFICATIONS OF PHILIP HAYET

Date	Case	Jurisdict	Party	Utility	Subject
			for Consumer Services		avoided cost tariff and remaining unsubscribed capacity
07/05	03-035-14	UT	Utah Committee for Consumer Services	PacifiCorp	Concerning PacifiCorp's Schedule 38 avoided cost proceeding
12/05	04-035-42	UT	Utah Committee for Consumer Services	PacifiCorp	Net power costs in General Rate Case
04/06	05-035-54	UT	Utah Committee for Consumer Services	PacifiCorp	Certification request to expand Blundell Geothermal Power Station. Related to Mid-American Energy Holding's Acquisition of PacifiCorp
05/06	22403-U	GA	Georgia Public Service Commission Staff	Georgia Power and Savannah Electric	March 2006 fuel cost recovery filing
2006	06-35-01	UT	Utah Committee for Consumer Services	PacifiCorp	2006 rate case, net power costs
08/06	U-21453	LA	Louisiana Public Service Commission Staff	Entergy Gulf States	Jurisdictional separation.
11/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana	Fuel adjustment clause filings
01/07	23540-U	GA	Georgia Public Service Commission Staff	Georgia Power	November 2005 fuel cost recovery filing
04/07	07-035-93	UT	Utah Committee for Consumer Services	PacifiCorp	General Rate Case
06/07	24505-U	GA	Georgia Public Service Commission Staff	Georgia Power	2007 Integrated Resource Planning
10/07	U-30334	LA	Louisiana Public Service Commission Staff	Cleco Power	2008 Short-Term RFP
04/08	26794-U (FCR-20)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing

QUALIFICATIONS OF PHILIP HAYET

Date	Case	Jurisdict	Party	Utility	Subject
2008	6630-CE-299	WI	Wisconsin Industrial Energy Group, Inc.	WEPCO	Certification Proceeding for environmental upgrades at Oak Creek power plant
07/08	ER07-956	FERC	Louisiana Public Service Commission	Entergy	2006 rough production cost equalization compliance filing in the System Agreement case
09/08	6680-CE-180	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light	Certification proceeding concerning Nelson-Dewey coal-fired generating unit
11/08	08-1511-E-GI	WV	West Virginia Energy Users Group	Allegheny Power	Fuel cost recovery filing
12/08	27800-U	GA	Georgia Public Service Commission Staff	Georgia Power	Vogtle 3 and 4 nuclear unit certification proceeding
2008	08-035-35	UT	Utah Committee for Consumer Services	PacifiCorp	Chehalis Combine Cycle Power Plant based on a waiver of the RFP solicitation process certification proceeding
07/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy	2007 rough production cost equalization compliance filing in the System Agreement case
07/09	U-30975	LA	Louisiana Public Service Commission Staff	SWEPCO and Cleco	Application to acquire the Oxbow Mine to supply Dolet Hills Power Station certification proceeding
09/09	E015/PA-09-526	MN	Large Power Intervenors	Minnesota Power	Request for approval to purchase Square Butte's 500 kV DC transmission line, restructure a coal based power purchase agreement
09/09	09-035-23 Direct	UT	Utah Office of Consumer Services	PacifiCorp	2009 rate case, net power costs
10/09	09A-415E	CO	Public Utilities Commission of Colorado	Black Hills/Colorado	CPCN application to construct two LMS 100 natural gas combustion turbine units
10/09	09-035-23 Surrebuttal	UT	Utah Office of Consumer Services	PacifiCorp	2009 rate case, net power costs
12/09	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	First Semi-Annual Vogtle Construction Monitoring Report

QUALIFICATIONS OF PHILIP HAYET

Date	Case	Jurisdict	Party	Utility	Subject
12/09	ER08-1224	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
2009	09-2035-01	UT	Utah Office of Consumer Services	PacifiCorp	2008 IRP
01/10	28945-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
2010	EL09-61	FERC	Louisiana Public Service Commission	Entergy	System Agreement, individual operating company sales
06/10	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Second Semi-Annual Vogtle Construction Monitoring Report
12/10	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Third Semi-Annual Vogtle Construction Monitoring Report
01/11	ER09-1350 Direct	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
02/11	ER09-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
04/11	33302-U (FCR-22)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
06/11	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fourth Semi-Annual Vogtle Construction Monitoring Report
09/11	U-31892	LA	Louisiana Public Service Commission Staff	Cleco Power	Settlement agreement, CPCN to upgrade Madison 3 coal unit to accommodate biomass fuel
11/11	26550-U	GA	Georgia Public Service Commission Staff	Georgia Power	Reacquisition of wholesale block capacity
11/11	34218-U	GA	Georgia Public Service Commission Staff	Georgia Power	Decertification of two aging coal units, acquire PPA resources, approve IRP update

QUALIFICATIONS OF PHILIP HAYET

Date	Case	Jurisdict	Party	Utility	Subject
12/11	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fifth Semi-Annual Vogtle Construction Monitoring Report
03/12	U-32148	LA	Louisiana Public Service Commission Staff	Entergy	Change of Control Proceeding to move to Midwest ISO
2012	20000-EA-400-11	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power	Certification of environmental upgrades at Naughton 3
05/12	35277-U (FCR-23)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
05/12	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Sixth Semi-Annual Vogtle Construction Monitoring Report
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers	Environmental upgrades in compliance with MATS and CSAPR
09/12	U-32275	LA	Louisiana Public Service Commission Staff	Dixie Electric Member Cooperative	Ten year power supply acquisition certification proceeding
12/12	EL09-61-002 Direct	FERC	Louisiana Public Service Commission	Entergy	Harm calculation, violation of System Agreement
12/12	U-32557	LA	Louisiana Public Service Commission Staff	Entergy	Certification of 28 MW PPA for renewable energy capacity (RAIN waste heat) in accordance with LPSC’s Renewable Energy Pilot
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy	Retail proceeding regarding termination of cross-PPAs
12/12	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Seventh Semi-Annual Vogtle Construction Monitoring Report
03/13	EL09-61-002 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy	Harm calculation, violation of System Agreement

QUALIFICATIONS OF PHILIP HAYET

Date	Case	Jurisdict	Party	Utility	Subject
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Mitchell Certificate of Public Convenience and Necessity
05/13	36498-U	GA	Georgia Public Service Commission Staff	Georgia Power	2013 IRP and request to decertify over 2,000 MW of coal-fired capacity
07/13	U-32785	LA	Louisiana Public Service Commission Staff	Entergy	8.5 MW PPA for renewable energy capacity (Agrilectric rice hull) in accordance with LPSC's Renewable Energy Pilot
08/13	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eighth Semi-Annual Vogtle Construction Monitoring Report
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers	Base rate case
05/14	13-035-184	UT	Utah Office of Consumer Services	PacifiCorp	2014 General Rate Case, net power cost
06/14	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Ninth/Tenth Semi-Annual Vogtle Construction Monitoring Report
07/14	20000-446-EA-14	WY	Wyoming Industrial Energy Consumers	PacifiCorp	2014 General Rate Case, net power cost
08/14	2000-447-EA-14	WY	Wyoming Industrial Energy Consumers	PacifiCorp	2014 Energy Cost Adjustment Mechanism application
08/14	14-035-31	UT	Utah Office of Consumer Services	PacifiCorp	2014 Energy Balancing Adjustment application
09/14	ER13-432	FERC	Louisiana Public Service Commission	Entergy	Allocation of Union Pacific Settlement Agreement benefits
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power	Kentucky Power Company's Fuel Adjustment Clause
12/14	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eleventh Semi-Annual Vogtle Construction Monitoring Report

QUALIFICATIONS OF PHILIP HAYET

Date	Case	Jurisdict	Party	Utility	Subject
05/15	14-035-140	UT	Utah Office of Consumer Services	PacifiCorp	Solar and wind capacity contribution avoided cost proceeding.
06/15	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twelfth Semi-Annual Vogtle Construction Monitoring Report
08/15	15-035-03	UT	Utah Office of Consumer Services	PacifiCorp	2015 Energy Balancing Adjustment application
09/15	14-035-114	UT	Utah Office of Consumer Services	PacifiCorp	Cost and Benefits of PacifiCorp's Net Metering Program
11/15	39638-U	GA	Georgia Public Service Commission Staff	Georgia Power	FCR-24 Fuel Cost Recovery Proceeding
11/15	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Thirteenth Semi-Annual Vogtle Construction Monitoring Report
5/16	40161	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power Company's 2016 IRP and Application for Decertification of Plant Mitchell Units 3, 4A, and 4B, Kraft Unit 1 CT, and Intercession City CT
6/16	29849	GA	Georgia Public Service Commission Staff	Georgia Power	Fourteenth Semi-Annual Vogtle Construction Monitoring Report
8/16	16-035-27	UT	Utah Office of Consumer Services	PacifiCorp	Renewable Energy Services Contract between Rocky Mountain Power and Facebook, Inc
8/16	16-035-01	UT	Utah Office of Consumer Services	PacifiCorp	2016 Energy Balancing Adjustment application
9/16	09-035-15	UT	Utah Office of Consumer Services	PacifiCorp	EBA Pilot Evaluation Direct Testimony
11/16	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fifteenth Semi-Annual Vogtle Construction Monitoring Report
11/16	09-035-15	UT	Utah Office of Consumer Services	PacifiCorp	EBA Pilot Evaluation Rebuttal Testimony
11/16	EL09-61-04	FERC	Louisiana Public Service Commission	Entergy	Violation of System Agreement, Phase III, Harm Calculation, Direct

QUALIFICATIONS OF PHILIP HAYET

Date	Case	Jurisdict	Party	Utility	Subject
3/17	EL09-61-04	FERC	Louisiana Public Service Commission	Entergy	Violation of System Agreement, Phase III, Harm Calculation, Rebuttal
6/17	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Sixteenth Semi-Annual Vogtle Construction Monitoring Report
9/17	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Direct
11/17	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Surrebuttal
4/18	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Response
4/18	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Rebuttal to Response
12/17	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Direct
1/18	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Rebuttal
4/18	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Second Rebuttal
6/18	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eighteenth Semi-Annual Vogtle Construction Monitoring Report
8/18	Cause 45052	IN	Indiana Coal Council	Vectren Energy Delivery of Indiana	Request for Approval of an 850 MW CCGT Plant
9/18	U-34836	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC	Authorization to Participate in a 50 MW Solar PPA
11/18	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Nineteenth Semi-Annual Vogtle Construction Monitoring Report
1/19	U-35019	LA	Louisiana Public Service Commission Staff	Entergy Louisiana	Authorization to Make Available Experimental Renewable Option and Rate Schedule RTO

QUALIFICATIONS OF PHILIP HAYET

Date	Case	Jurisdict	Party	Utility	Subject
4/19	42310-U	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power's 2019 IRP Proceeding
11/19	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty/Twenty-First Semi-Annual Vogtle Construction Monitoring Report

ADDITIONAL JUDICIAL PROCEEDINGS AND OTHER PROJECT INFORMATION

- 1995 – 2000 - Modeled the Singapore Power Electricity System and analyzed the benefits of dispatching a new oil-fired unit within the system, BHP Power
- 1995 – 2000 - Modeled the Australian National Energy Market to develop market based energy price forecasts on behalf of an Independent Power Producer in Australia, BHP Power
- 1995 – 2000 - Analyzed the benefit of purchasing existing gas-fired steam turbine units within the Australian market, BHP Power
- 1995 – 2000 Developed market price forecasts for South Australia as part of the evaluation of a new gas fired combined cycle unit, BHP Power
- 1995 – 2000 - Modeled the Vietnam Electricity System as part of a project to develop Least Cost Expansion plans for Vietnam, EVN State Utility
- 1995 – 2000 - Assisted in the evaluation of Phu My CCGT power plant in Vietnam, BHP Power
- 1995 – 2000 - Assisted in the development of Market Price Forecasts in several regions of the US. These forecasts were used as the basis for stranded cost estimates, which were filed in testimony in a number of jurisdictions across the country.
- 1995 – 2000 - Conducted research regarding ISO Tariffs and Operations for the PJM Power Pool, the California ISO, and the Midwest ISO on behalf of a Japanese Research.
- 1995 – 2000 - Performed research on numerous electric utility issues for 3 Japanese research organizations. This was primarily related to deregulation issues in the US in anticipation of deregulation being introduced in Japan.
- 1995 – 2000 - Critiqued the IRP filings of 5 utilities in South Carolina on behalf of the South Carolina State Energy Office
- 1999 - Helped to analyze the rate structure and develop an electricity price forecast for the Metropolitan Atlanta Rapid Transit Authority (MARTA) in Atlanta, Georgia

QUALIFICATIONS OF PHILIP HAYET

- August 2002 – Expert Report, Civil Action No. 1:00-cv-1262 in the United Stated District Court for the Middle District of North Carolina, United States v. Duke Energy Corporation, Department of Justice
- 2002 - Worked on behalf of the Utah Committee of Consumer Services to provide guidance and assist in the analysis of PacifiCorp's 2002 Integrated Resource Plan.
- July 2003 - Worked on behalf of the Oregon Public Utility Commission to Audit PacifiCorp's Net Power Costs per a Settlement Agreement accepted by the Public Utility Commission of Oregon in its Order No. 01-787. Audit report in Docket No. UE-116 filed July 2003.
- 2003 - Regulatory support to the Utah Committee of Consumer Services regarding PacifiCorp's 2003 Utah General Rate Case Docket # 03-2035-02.
- 2004 – Assistance to the Utah Committee of Consumer Services to analyze a series of power purchase agreements and special contracts between PacifiCorp and several of its industrial customers.
- 2005 - Worked on behalf of the Utah Committee of Consumer Services to help analyze PacifiCorp's restructuring proposals.
- 2005 - Assisted the Utah Committee of Consumer Services by evaluating PacifiCorp's 2005 IRP and assisted in writing comments that were filed with the Commission.
- 2007 - Assisted the Utah Committee of Consumer Services to evaluate PacifiCorp's 2007 IRP.
- 2007 - Conducted an investigation of the Southern Company interchange accounting and fuel accounting practices on behalf of the Georgia Public Service Commission Staff (Docket 21162-U).
- 2008 - Assisted the Louisiana Public Service Commission Staff with the review and evaluation of Cleco Power's 2008 Short Term RFP and its 2010 Long-Term RFP.
- 2008 - Assisted the Utah Committee of Consumer Services by participating in a collaborative process to develop an avoided cost tariff for large QFs.
- 2008 - Assisted the Louisiana Public Service Commission Staff with a rulemaking for the opportunity to implement a Renewable Portfolio Standard in Louisiana. (Docket No. R-28271 Sub-Docket B)
- April 2011 – Initial Expert Report, Civil Action No. 2:10-cv-13101-BAF-RSW, on behalf of the Department of Justice in US District Court, United States v.Detroit Edison
- June 2011 – Rebuttal Expert Report, Civil Action No. 2:10-cv-13101-BAF-RSW, on behalf of the Department of Justice in US District Court, United States Detroit Edison

- 2011 - Assisted the Georgia Public Service Commission Staff to investigate the acquisition of additional coal and combustion turbine capacity currently wholesale capacity (Docket 26550).
- 2012 - Assisted the Louisiana Public Service Commission Staff with a rulemaking to design Integrated Resource Planning ("IRP") rules. (Docket No. R-30021)
- December 2013 – Expert Report, Civil action no. 4:11-cv-00077-RWS, on behalf of the Department of Justice in US District Court, United States v. Ameren Missouri.

PUBLICATIONS AND PRESENTATIONS

Co-authored "Review of EPA's Section 111(d) CO_2 Emission Rate Goals for the State of Montana, on behalf of the Montana Large Customer Group, October 2014.

Authored "Singapore's Developing Power Market", which appeared in the July/August 1999 edition of Power Value Magazine

Co-authored "The New Energy Services Industry – Part 1", which appeared in the January/February 1999 edition of Power Value Magazine.

Co-authored and Presented "Evaluation of a Large Number of Demand-Side Measures in the IRP Process: Florida Power Corporation's Experience", Presented at the 3rd International Energy and DSM Conference, Vancouver British Columbia, November 1994

Co-authored "Impact of DSM Program on Delmarva's Integrated Resource Plan", Published in the 4th International Energy and DSM Conference Proceedings, held in Berlin, Germany, 1995

Presentation – Law Seminars International, Electric Utility Rate Cases, Case Study of the Louisiana Public Service Commission's Quick Start Energy Efficiency Program, March 2015.