

**BEFORE THE  
GEORGIA PUBLIC SERVICE COMMISSION**

**IN THE MATTER OF: GEORGIA POWER  
COMPANY'S TWENTIETH/TWENTY-  
FIRST SEMI-ANNUAL VOGTLE  
CONSTRUCTION MONITORING REPORT**

**DOCKET NO. 29849**

**DIRECT TESTIMONY  
AND EXHIBITS  
OF  
TOM NEWSOME, PE, CFA  
PHILIP HAYET**

**ON BEHALF OF THE  
GEORGIA PUBLIC SERVICE COMMISSION  
PUBLIC INTEREST ADVOCACY STAFF**

**NOVEMBER 22, 2019**

## **TABLE OF CONTENTS**

I. INTRODUCTION .....	2
II. COMPANY’S VCM 20/21 FILING .....	5
III. STAFF’S ECONOMIC EVALUATION .....	9
Staff’s Assumptions .....	9
Staff’s Economic Evaluation Results .....	18

---

**I. INTRODUCTION**

**Q. PLEASE STATE YOUR NAMES, TITLES, 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 analysis, 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. PLEASE PROVIDE AN OVERVIEW OF THE PROJECT.**

A. Georgia Power Company's ("the Company" or "Georgia Power") Twentieth/Twenty-First Vogtle Construction Monitoring ("VCM 20/21") Report covers the twelve-month period of July 1, 2018 through June 30, 2019. Consistent with its 17<sup>th</sup> through 19<sup>th</sup> VCM filings, the Company continues to forecast a schedule delay of 68 months, with commercial operation dates ("CODs") for Units 3 and 4 planned for November 2021 and 2022, respectively. The VCM 20/21 filing states that the Company and Southern Nuclear Operating Company ("SNC") continue to project that Georgia Power's share of Vogtle Units 3 and 4 ("Project" or "Units") construction and capital cost will be \$8.4 billion. However, at this time, the Company has only stated that it intends to seek approval of \$7.3 billion in capital costs. Of the approximate \$1.1 billion difference, the Company has stated it will absorb \$694 million and has not decided whether it will seek recovery of the remaining \$366 million contingency from the Commission.<sup>1</sup>

Staff included the \$366 million contingency in its cost to complete economic analysis since the Company expects to incur the cost and may seek recovery of the costs from ratepayers.<sup>2</sup> Therefore, Staff's revised capital cost estimate is \$7.7 billion (\$7.3 billion + \$366 million) with a financing cost of \$3.1 billion, for a Total Project Cost of \$10.8 billion.<sup>3</sup>

Staff reviewed the Company's economic analysis and presents its own independent

---

<sup>1</sup> At Georgia Power's November 12, 2019 Direct Testimony hearing, Company witness Kuczynski discussed that a portion of the \$366 million contingency amount has now been allocated (about \$30 million), and he stated, "...we still expect that the remaining balance of contingency will be allocated by the completion of the project..." The Company also stated in its VCM 20/21 Report at pg. 4, "The Company is not requesting Commission approval of these costs in this filing but may request the Commission to evaluate expenditures allocated to contingency for rate recovery as and when appropriate." The Company also recognized it would incur the \$366 million of contingency in its SEC filings.

<sup>2</sup> Staff's inclusion of the \$366 million for economic modeling does not constitute an agreement by Staff that these costs should be recovered from ratepayers.

<sup>3</sup> The \$10.8 billion Total Project Cost is the net of the Toshiba Parental Guarantee (\$1.492 billion) that was applied as an offset to the construction balance and includes the return on equity ("ROE") reductions provided in the Supplemental Information Review ("SIR") stipulation and the 17<sup>th</sup> VCM Order. The \$10.8 billion Total Project Cost represents about an 80 percent increase from the Company's projection of \$6.1 billion at Certification.

1 economic evaluation of the Project in this testimony. Similar to Staff's analyses in prior  
2 VCM proceedings, Staff performed independent economic studies over a range of  
3 assumptions that in some cases differ from the Company's assumptions and  
4 methodologies.

5 Staff's cost to complete economic analysis indicates it is *economic to continue* the Project  
6 *if* the Company meets its current cost and COD forecasts. However, Staff determined that  
7 a delay beyond 18 months from the current regulatory CODs of November 2021/2022  
8 could result in the Project becoming uneconomic to continue. This is the result of the high  
9 cost being incurred by the Company each month during construction.<sup>4</sup> This cost to  
10 complete economic analysis ignores the over \$5 billion in capital costs already spent on  
11 the Project as well as the \$2 billion in financing costs already recovered from ratepayers  
12 through the Nuclear Construction Cost Recovery ("NCCR") tariff.

13 **Q. WHY DO YOU EXCLUDE THE \$7 BILLION THE COMPANY HAS ALREADY**  
14 **INCURRED IN YOUR COST TO COMPLETE ANALYSIS?**

15 A. The purpose of a cost to complete analysis is to examine whether it is economic to finish  
16 the Project, not to evaluate whether the Project is economic for ratepayers over the entire  
17 lifecycle (construction and operating periods). Therefore, only prospective costs should be  
18 included in the cost to complete economic analysis. However, Staff also performed a  
19 lifecycle economic analysis which included all costs that were excluded from the cost to  
20 complete analysis. The results from lifecycle economic analysis are presented later in this  
21 testimony.

---

<sup>4</sup> For example, the Company incurred approximately \$137 million per month of capital and financing cost during the first nine months of 2019.

---

**II. COMPANY'S VCM 20/21 FILING**

**Q. WHAT CONVENTION DO YOU USE TO REFER TO THE DIFFERENT CASES  
EVALUATED IN THIS PROCEEDING?**

A. Our practice has been to identify the delay cases based on the number of months of delay from the original certified in-service dates for the Units, which were April 2016/2017. Since the Company's latest in-service date estimate is November 2021/2022, Staff refers to this as the 68-month delay case. The Company refers to the same case as its +29-month case in reference to its prior CODs of June 2019/2020, as was reflected in the Company's 15<sup>th</sup> and 16<sup>th</sup> VCM filings.

**Q. PLEASE EXPLAIN HOW THE FINANCING COST INCURRED BY THE  
COMPANY DURING THE CONSTRUCTION OF THE UNITS IS RECOVERED  
FROM RATEPAYERS.**

A. Of the Company's \$3.1 billion financing cost, \$2.8 billion is being recovered during construction through the Nuclear Construction Cost Recovery ("NCCR") tariff. The \$2.8 billion amount consists of \$0.1 billion in financing cost that occurred prior to 2011 when the NCCR tariff began,<sup>5</sup> and an additional \$2.7 billion of financing cost that will be incurred from 2011 through the current CODs. The \$2.7 billion amount consists of \$0.76 billion of interest on debt and \$1.96 billion of return on equity ("ROE" or "profit"). An additional financing cost of \$0.3 billion will be deferred and recovered over the operating life of the Units through Allowance for Funds Used During Construction ("AFUDC") accounting.

**Q. HOW MUCH OF THE NCCR TARIFF REVENUE REQUIREMENT WILL BE**

---

<sup>5</sup> The \$0.1 billion financing cost amount that was incurred prior to 2011 was recovered over the period of 2011 to 2015.

---

**COLLECTED FROM RATEPAYERS DURING THE CONSTRUCTION PERIOD?**

A. Staff estimates the Company will collect approximately \$3.9 billion from ratepayers through the NCCR tariff. The \$3.9 billion is composed of \$2.8 billion in financing cost and \$1.1 billion in income tax expense.<sup>6</sup>

**Q. HOW MUCH HAS ALREADY BEEN SPENT ON THE PROJECT THROUGH THE END OF THE VCM 20/21 PERIOD?**

A. As of June 30, 2019, the Company has incurred \$5.19 billion of capital and construction cost and \$2.03 billion of financing cost for a total cost of \$7.22 billion.<sup>7</sup>

**Q. HOW MUCH REMAINS TO BE SPENT BY THE COMPANY ON THE PROJECT THROUGH THE END OF CONSTRUCTION?**

A. Over the remainder of the construction period, the Company estimates it will incur an additional \$2.11 billion of construction and capital costs and an additional \$1.10 billion of financing cost for total cost of \$3.21 billion.<sup>8</sup>

**Q. DID THE COMPANY CHANGE ANY MODELING ASSUMPTIONS FROM ITS VCM 19 FILING?**

A. Yes, and the changes are discussed on page 40 of the VCM 20/21 Report. The Company notes that it updated all of its major underlying planning assumptions, including fuel forecasts, load forecasts, and new generation technology costs. The changes the Company made are the same as what was included in the recent 2019 Integrated Resource Plan (“IRP”) (Docket No. 42310). However, one difference compared to the IRP is that the

---

<sup>6</sup> Refer to Staff data requests 170-25 and 170-27.

<sup>7</sup> The \$5.19 billion capital cost value is net of the \$1.49 billion Toshiba Parental Guarantee applied as an offset to the construction balance that otherwise would have been \$6.68 billion.

<sup>8</sup> As previously discussed, Staff is including the \$366 million in its capital cost estimate, so based on that the estimate of the remaining capital cost to be incurred is \$2.48 billion rather than the \$2.11 billion value the Company reported.

1 Company included Gulf Power loads and resources in its IRP databases, but it removed the  
2 Gulf Power loads and resources from its VCM 20/21 databases. In addition, the Company  
3 made changes to Pre-in-service O&M, post-in-service O&M, post-in-service ongoing  
4 capital, Ad Valorem taxes, its marginal cost of capital, nuclear fuel costs, and it ignored  
5 cancellation costs in its analysis. Overall, the changes had a small impact on the cost-to-  
6 complete economic analysis results.

7 In addition, with regard to the new Vogtle Units, the Company noted at page 40 of its VCM  
8 20/21 Report that “The average summer net output has been updated based on the results  
9 of the Vogtle 3 & 4 Power Output Assessment, which was filed as an update to STF-132-  
10 19 in the Company’s May 2019 Monthly Status Report.” This amounts to about an 11 MW  
11 increase in Georgia Power’s share of the capacity of the two new Vogtle Units.

12 **Q. WHAT ECONOMIC EVALUATION DID THE COMPANY PERFORM IN THIS**  
13 **PROCEEDING?**

14 A. The Company performed a single cost-to-complete economic analysis study, which it  
15 presented in Table 4.1 of its VCM 20/21 report. The Company’s analysis compared the  
16 remaining cost to complete the Vogtle Project, referred to as the “Completion Case”, to the  
17 cost to cancel Vogtle and construct an equivalent amount of combined cycle capacity,  
18 referred to as the “Cancellation Case”. The Company’s analysis forecasts that there will  
19 be a \$2.8 billion benefit on an expected value basis to continue construction (2021 NPV  
20 dollars).<sup>9</sup>

21 **Q. DOES STAFF HAVE ANY CONCERNS WITH THE COMPANY’S ECONOMIC**  
22 **EVALUATION?**

23 A. Yes. Staff continues to have concerns with the Company’s analysis. First, as Staff

---

<sup>9</sup> This amounts to \$2.2 billion on a 2018 NPV basis.



discussed in prior proceedings, a correct and accurate economic analysis should include all differences between cancelling and continuing the Project, including, among others, accounting for prospective incremental income tax impacts.

Second, the Company omitted the \$366 million contingency in its analysis without agreeing to absorb the cost. The following table summarizes the capital costs included in the Company's Table 1.1 and its economic analysis and compares this to Staff's capital cost assumption.

**Table 1**  
**Comparison of the Company's and Staff's**  
**Capital Cost Assumption in VCM 20/21(\$ Millions)**

	<b>Capital Cost</b>
Capital Cost	9,486
Toshiba Parental Guarantee	(1,492)
Georgia Power to Absorb	(694)
Company's Capital Cost	7,300
Contingency	366
Staff's Capital Cost	7,667

Third, Staff disagrees with the Company's interpretation of the VCM 17 Order, and some of the modeling assumptions that the Company incorporated in its VCM 20/21 analysis. Specifically, Staff disagrees with the Company's interpretation of the amount of capital investment to be placed into the rate base when Unit 3 goes into service, and the recovery of the remaining investment and operations costs until Unit 4 is complete.

Fourth, although Staff determined that the Company lowered its natural gas price forecasts considerably in this VCM proceeding compared to VCM 19, Staff continues to disagree with the Company's approach of deriving its forecasts using only a single source rather than multiple sources of information.

Finally, Staff has concerns with the Company's carbon modeling assumptions. One concern is that the Company has not updated its carbon dioxide emission price forecast even though the Clean Power Plan has been repealed. The second concern, as discussed in Staff's IRP testimony, is that in some scenarios the only type of combined cycle unit the Company allows to be added as new resource additions are combined cycle units with carbon sequestration capability. These units are extremely expensive, not commercially available, and unlikely to ever be added as the Company has modeled them.

**Q. WHAT SCENARIO DID THE COMPANY EVALUATE THAT LED TO THE RESULTS IT PRESENTED IN TABLE 4.1?**

A. The Company evaluated its current base case in-service date assumptions based on the 68-month delay case. The Company performed its usual set of nine analyses evaluating all combinations of three fuel price cases (Low, Mod, High) and three carbon dioxide emission price cases (\$0/Ton, \$10/Ton, \$20/Ton).

### III. STAFF'S ECONOMIC EVALUATION

#### Staff's Assumptions

**Q. WHAT ANALYSES DID STAFF PERFORM IN ITS VCM 20/21 EVALUATION?**

A. Staff conducted cost-to-complete analyses to evaluate the reasonableness of the Company's results using alternative modeling assumptions. Staff performed an evaluation of the Company's 68-month delay scenario with alternative assumptions and conducted a sensitivity case assuming a 24-month delay beyond the Company's current November 2021/2022 CODs (for a total delay of 92 months).

**Q. WHAT CHANGES TO ASSUMPTIONS DID STAFF MAKE TO CREATE**

---

**STAFF'S CASES?**

A. Staff made the following adjustments in its cases:

- Set the net present value date to 2018,
- Included the \$366 million contingency cost,
- Accounted for certain prospective incremental impacts of sunk costs, primarily the income tax benefit of approximately \$1.2 billion if Vogtle 3 & 4 were cancelled,<sup>10</sup>
- Relied on a different interpretation of VCM Order 17 and the Supplemental Information Report ("SIR") Stipulation that does not force ratepayers to pay costs that have not been determined to be prudent,
- Used a revised set of natural gas price forecasts,
- Used a revised set of Carbon Dioxide ("CO<sub>2</sub>") emission price forecasts, and;
- Staff allowed Strategist the option of choosing the most economic combined cycle resource with or without carbon dioxide sequestration. Under certain circumstances, the Company required that any combined cycle resource added after a certain date would need to include carbon sequestration capability.

**Q. DISCUSS THE CHANGE STAFF MADE TO THE COMPANY'S PRESENT VALUE DATE.**

A. Staff used 2018 as the measurement date for present value calculations, rather than 2021. As mentioned earlier, using a common present value year allows for consistency in evaluating past, current, and future economic evaluations.

**Q. PLEASE EXPLAIN STAFF'S CONSIDERATION OF THE \$366 MILLION IN**

---

<sup>10</sup> \$1.2 billion = \$5.9 billion write-off x 21% tax rate

---

**CONTINGENCY AND HOW IT IS MODELED.**

A. As discussed above, Staff believes the \$366 million contingency amount should be included in the economic evaluation. While Staff includes the contingency cost in its economic analysis, this should not be interpreted to mean that Staff believes customers should be responsible for these costs.

**Q. EXPLAIN THE CHANGES STAFF MADE TO ACCOUNT FOR THE PROSPECTIVE INCREMENTAL INCOME TAX IMPACTS OF SUNK COSTS.**

A. Staff accounted for two important incremental impacts of sunk costs in its cost to complete analysis. Staff properly captured the impact of prospective income taxes stemming from sunk costs and modeled the income tax write-off (savings) that Georgia Power would be entitled to if the Project were cancelled. Georgia Power on the other hand incorrectly assumes that this tax benefit can be ignored.<sup>11</sup>

**Q. DOES STAFF AND THE COMPANY DIFFER ON THE INITIAL RATEMAKING TREATMENT FOR UNIT 3 ONCE UNIT 3 IS PLACED INTO COMMERCIAL OPERATION?**

A. Yes. Staff and the Company have different interpretations of the 17<sup>th</sup> VCM Order and Supplemental Information Report (“SIR”) Stipulation.

**Q. PLEASE EXPLAIN STAFF’S INTERPRETATION OF THE 17<sup>th</sup> VCM ORDER.**

A. Both Staff’s and the Company’s economic analyses assume a portion of Unit 3 and common capital costs should be placed in rate base and reflected in rates in the first month

---

<sup>11</sup> The \$1.2 billion income tax benefit from canceling Vogtle would impact the cost to complete analysis by \$255 million on a 2018 net present value (NPV) basis. The underlying assumptions include a sunk cost of \$5.9 billion as of January 2020, a 15-year modified accelerated cost recovery system (“MACRS”) tax depreciation schedule for the \$5.9 billion in the Continuation Case, and a 3-year straight-line tax depreciation schedule (abandonment loss) for the \$5.9 billion in the Cancellation Case.

1 after the Unit 3 COD. But, they differ on the exact amounts. As Staff described in its  
2 VCM 18 and 19 testimonies, the SIR Stipulation provided that capital costs verified and  
3 approved through December 2015 would be deemed prudent except under special  
4 circumstances. The SIR Stipulation also provided that the Vogtle Units 3 and 4 costs would  
5 be placed in retail rate base on the latter of either December 31, 2020, or Unit 4 reaching  
6 commercial operation.

7 The Commission's 17<sup>th</sup> VCM Order modified the treatment of a portion of the Unit 3 and  
8 common costs. Unit 3 and common costs that had been verified and approved through  
9 December 2015 could now go into base rates after Unit 3 goes into commercial operation.  
10 On page 18, the 17<sup>th</sup> VCM Order states:

11 **ORDERED FURTHER**, that effective the first month after Unit 3 is in  
12 Commercial Operation, which is expected to be in November 2021, retail base rates  
13 shall be adjusted to include the costs related to Unit 3 and common facilities  
14 deemed prudent in the January 3, 2017 Stipulation. This rate adjustment will be  
15 effective the first month after Unit 3 is in commercial operation.

16 All the remaining Unit 3 costs (as well as all the Unit 4 costs) would continue to stay out  
17 of base rates until after Unit 4 is in commercial operation. Again, from page 18 of the 17<sup>th</sup>  
18 VCM Order:

19 **ORDERED FURTHER**, that once the fuel load of Unit 4 is reached, the Company  
20 may make a filing with the Commission to determine the adjustment to retail base  
21 rates necessary to include the remaining amounts of Units 3 and 4 into retail base  
22 rates. During this review, the Commission will determine the remaining issues  
23 pertaining to prudence of Unit 3 and 4 costs. Such rate adjustment will be effective  
24 the first month after Unit 4 is Commercially Operational.  
25 (Emphasis added).

26 The 17<sup>th</sup> VCM Order further states that “[t]he balance of the proceeds received from  
27 Toshiba, net of the Company's costs to obtain that payment and net of the costs of  
28 providing ... customer credits, will be applied to the CWIP balance.” The CWIP balance

contains only costs already incurred by the Company. It does not contain any future costs. And only some of the costs in CWIP have been deemed prudent.<sup>12</sup> It is Staff's position that the Toshiba Parental Guarantee ("TPG") funds can only be applied to offset costs that have been deemed prudent by the Commission.<sup>13</sup> Otherwise, ratepayers may be paying costs which the Commission has not yet, and may never, find to be prudent. Therefore, the TPG funds can only be applied to the \$3.5 billion deemed prudent in the SIR stipulation.

**Q. HOW DOES THIS DIFFERENCE IN INTERPRETATION IMPACT THE AMOUNT OF UNIT 3 AND COMMON COSTS THAT GO INTO BASE RATES WHEN UNIT 3 IS COMPLETED?**

A. Based on this interpretation of the SIR stipulation and the VCM 17 Order Staff determined that the Company should be allowed to place \$1.13 billion of Unit 3 Capital and Common capital cost into rate base the month following commercial operation, whereas the Company determined that it should be allowed to place \$2.34 billion into rate base at that time.<sup>14</sup> Additionally, Staff assumed that capital costs placed into rate base the month after Unit 3 is completed should be taken entirely from the capital costs underlying the NCCR tariff to match how these capital costs are financed. This contrasts to the Company's interpretation that assumes Unit 3 costs put into rate base would be partly taken from

<sup>12</sup> When the VCM 17 Order was issued, the CWIP balance was \$3.902 billion, of that \$3.509 billion had been deemed prudent by the SIR Stipulation. The VCM 17 Order also verified another \$542 million, which has not yet been deemed prudent. Reducing the CWIP balance by the \$1.493 net Toshiba payment, resulted in a new CWIP balance of \$2.951 billion ( $\$3.902 + .542 - 1.493$ ). Despite this, the Company apparently contends that ratepayers still owed the Company the entire \$3.509 billion, which was more than the entire CWIP balance.

<sup>13</sup> As Commissioner Echols explained at the December 21, 2017 Special Administrative Session, "The owners ... achieved payment in full for that parent guarantee but they achieved it for the customers' benefit and that's who should benefit." Trans., pg. 7-8 (Emphasis added). Customers don't benefit from the Toshiba payment unless it is applied to a cost that would otherwise be recoverable from customers.

<sup>14</sup> The TPG proceeds of \$1.493 billion were allocated in full against the \$3.509 billion capital costs incurred through December 31, 2015, netting to \$2.016 billion. Staff assumed 56% of this amount, or \$1.129 billion would be placed in-service the month after Unit 3 is completed. The Company assumed no TPG offset and assumed 66.6% of the amount, or \$2.34 billion, would be placed in service the month after Unit 3 is completed. See STF 137-9 part d.

AFUDC instead of exclusively from NCCR, which results in more costs remaining to be recovered through the NCCR Tariff at the same time that base rates are adjusted.

**Q. ARE THERE ANY OTHER DIFFERENCES IN HOW STAFF AND THE COMPANY TREAT COSTS RELATING TO UNIT 3?**

A. Staff has also determined that depreciation on the Unit 3 and Common amounts not placed into rate base upon Unit 3 completion should be assigned to the Company. Likewise, O&M and decommissioning expenses should not be charged to customers until Unit 4 is complete and the Project has been reviewed.<sup>15</sup> Financing costs on the Unit 3 capital balance not put into rate base would continue to be recovered, through either the NCCR tariff or capitalized through AFUDC accounting, at the reduced ROE rates consistent with the SIR stipulation and the 17<sup>th</sup> VCM Order.

It is important to note that Staff's interpretation reduces the Project's revenue requirements and therefore, increases the economic value of the Project to customers.

**Q. WHAT IS THE FINANCIAL IMPACT ON RATEPAYERS OF STAFF'S AND THE COMPANY'S DIFFERENT INTERPRETATIONS OF THE 17<sup>th</sup> VCM AND SIR STIPULATION?**

A. The revenue requirement collected from ratepayers under base rates during the first year

---

<sup>15</sup> The VCM 17 Order provides that when Unit 3 goes into commercial operation, rates are only adjusted to include the portion of the costs deemed prudent in the January 3, 2017 Stipulation that are allocable to Unit 3 and common facilities. VCM 17 Order, p. 14, para. 8. None of these additional costs meet that criteria. Instead, these costs cannot go into rates until Unit 4 goes into commercial operation, VCM 17 Order, p. 14, para. 10 ("*upon reaching fuel load of Unit 4, the Company may make a filing with the Commission to determine the adjustment to retail base rates necessary to include the remaining amounts of Units 3 and 4 into retail base rates. During this review, the Commission will determine the remaining issues pertaining to prudence of Unit 3 and 4 costs. Such rate adjustment will be effective the first month after Unit 4 is Commercially Operational.*"); p. 16, para. 14 ("*All Commission decisions regarding cost recovery will be made after a prudence review at the end of construction of Units 3 and 4.*").

1 of Unit 3 commercial operation would be materially different. Under Staff's interpretation  
2 the base rate revenue requirement would be approximately \$450 million. Under the  
3 Company's interpretation the base rate revenue requirement would be approximately \$700  
4 million.<sup>16</sup> Ratepayer bills would be lower by approximately \$250 million under Staff's  
5 interpretation during the year between the Unit 3 and Unit 4 COD dates. This reduction of  
6 ratepayer bills would increase if Unit 4 COD was extended beyond the planned one year  
7 from Unit 3 COD.

8 **Q. PLEASE DISCUSS YOUR REVIEW OF THE COMPANY'S NATURAL GAS**  
9 **PRICE FORECASTS.**

10 A. As Staff noted in prior VCM proceedings and the recent 2019 IRP proceeding, Staff has  
11 been and continues to be concerned about the Company's reliance on a single source,  
12 Charles River Associates ("CRA"), for developing its natural gas price forecasts. The  
13 Company continued this practice in VCM 20/21. Staff's concern has been that without  
14 adjusting its forecasts based on other information that is available, the Company could end  
15 up with forecasts that are out of line with other industry trends. In fact, Staff has noted on  
16 several occasions that the Company's forecasts have appeared to be too high.

17 **Q. DID STAFF COMPARE THE COMPANY'S NATURAL GAS PRICE FORECAST**  
18 **TO OTHER RECENT PUBLICLY AVAILABLE FORECASTS IN THIS VCM?**

19 A. Yes. The Company's natural gas price forecast in this VCM is essentially the same as what  
20 it used in its 2019 IRP. In this VCM, Staff compared Georgia Power's underlying Henry  
21 Hub natural gas price forecast to projections that are publicly available from other utility

---

<sup>16</sup> The Company assumes a deferral of the Unit 3 depreciation cost not placed in rate base upon Unit 3's completion date. The Company also assumes that after the Unit 4 COD date, it would get to recover the deferred Unit 3 depreciation costs over a five-year period.



1 companies including the Tennessee Valley Authority (“TVA”)<sup>17</sup>, Southwestern Electric  
2 Power Company (“SWEPCO”)<sup>18</sup>, Entergy Louisiana, LLC (“ELL”)<sup>19</sup>, Xcel Minnesota<sup>20</sup>,  
3 as well as the United States Energy Information Administration (“EIA”).<sup>21</sup> As in the IRP,  
4 Staff found that the Company’s High Gas Price forecast appears to be the highest of the  
5 High Gas Price Forecasts reviewed, the Company’s moderate gas price forecast appears to  
6 be slightly above the average consensus forecast that Staff developed, and the Company’s  
7 low gas price forecast appears to be below the average consensus forecast. Staff developed  
8 consensus average Low, Mod, and High gas price forecasts for its analyses using the  
9 publicly available data it collected as it had done in prior VCMs.

10 **Q. PLEASE EXPLAIN STAFF’S CONCERN REGARDING THE COMPANY’S CO<sub>2</sub>**  
11 **EMISSION PRICE FORECAST.**

12 A. Staff noted in its VCM 19 and 2019 IRP testimonies that it no longer seems reasonable for  
13 the Company to use a CO<sub>2</sub> emission price forecast that was originally based on the  
14 Environmental Protection Agency’s (“EPA”) Clean Power Plan rule, given that rule has  
15 been repealed and replaced by the Affordable Clean Energy (“ACE”) rule. Staff believes  
16 that the Company’s CO<sub>2</sub> emission price forecast is overstated based on the high annual  
17 CO<sub>2</sub> emission price escalation rate that the Company relies on for every year of the study  
18 period covering the 60-year life of the new Vogtle Units. Though Staff acknowledges there  
19 is tremendous uncertainty about what CO<sub>2</sub> emission prices may be imposed in the future,

---

<sup>17</sup> “2019 Integrated Resource Plan, Volume I – Draft Resource Plan,”

[https://www.tva.gov/file\\_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/2019%20Documents/TVA%20Draft%20IRP%20Vol%20I-reduced.pdf](https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/2019%20Documents/TVA%20Draft%20IRP%20Vol%20I-reduced.pdf), pgs. E-7 and E-8.

<sup>18</sup> “2019 Draft Integrated Resource Plan,” <http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=c33b4da2-6ac0-459c-ae6d-a0620eed2809>, pg. 152.

<sup>19</sup> “Data Assumptions and Study Description,” [https://www.entergy-louisiana.com/userfiles/content/irp/2019/ELL\\_2019\\_IRP\\_Assumptions.pdf](https://www.entergy-louisiana.com/userfiles/content/irp/2019/ELL_2019_IRP_Assumptions.pdf), pg. 22.

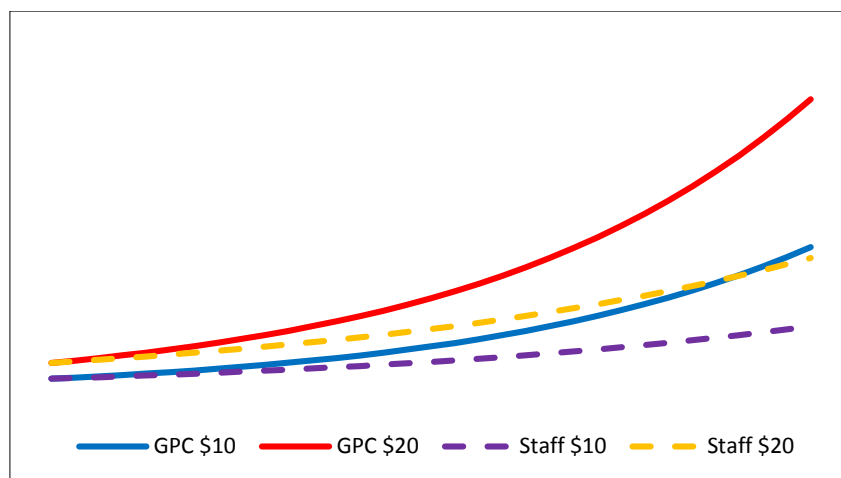
<sup>20</sup> 2019 IRP data request,  
<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bF012F96C-0000-C414-9F8B-072BBCC2B2C9%7d&documentTitle=20199-155648-01>

<sup>21</sup> All projections gathered from utilities companies were from these companies most recent IRPs, in which the data was extracted from the graphs and tables that those companies presented in their public filings.

Staff believes it is appropriate to lower the Company's CO<sub>2</sub> emission price forecast. Staff reduced the Company's significant nominal escalation rate to about 4.5 percent per year.

The following graph provides a comparison of the Company's and Staff's CO<sub>2</sub> price forecasts for the \$10/Ton and the \$20/Ton cases. The graph demonstrates how dramatically the Company's CO<sub>2</sub> prices increase under its Clean Power Plan modeling approach.

**Figure 1**  
**Nominal CO<sub>2</sub> price per Short Ton**



**Q. PLEASE EXPLAIN STAFF'S CONCERN REGARDING THE COMPANY'S REQUIREMENT THAT UNDER CERTAIN CIRCUMSTANCES ANY ADDED COMBINED CYCLE RESOURCE HAD TO HAVE CARBON SEQUESTRATION CAPABILITY.**

**A.** Staff disagrees with this assumption. It has been the Company's practice under certain circumstances to only permit combined cycle resources with carbon sequestration capability to be added in resource planning analyses when combined cycle resources are selected as resource additions. This combined cycle selection requirement is only modeled

1 in cases with \$10/Ton and \$20/Ton CO<sub>2</sub> costs, and is only required after a certain date,  
2 which is different in the two CO<sub>2</sub> cases. Before those dates, the Company permits Strategist  
3 to add combined cycle resources without carbon sequestration technology. Similarly, in  
4 \$0/Ton CO<sub>2</sub> cases, combined cycle resource options are not required to include carbon  
5 sequestration technology either. Combined cycle units modeled with carbon sequestration  
6 technology are substantially more expensive than combined cycle units without that  
7 technology.

8 **Q. WHY DOES STAFF DISAGREE WITH THIS PRACTICE?**

9 A. As Staff mentioned in its 2019 IRP testimony, this technology is extremely expensive and  
10 not yet commercially available, and Staff is not aware of when it could even become  
11 commercially available for use in Georgia. Given that the Company has modeled this  
12 technology for many years, and it still appears no closer to being commercially available,  
13 Staff decided to remove this constraint. Staff still left combined cycle options with  
14 sequestration in the model, however, Staff allowed the model to determine based on  
15 economics whether combined cycle resources with or without this technology should be  
16 added.

17  
18 **Staff's Economic Evaluation Results**

19  
20 **Q. PLEASE PROVIDE A TABLE SIMILAR TO TABLE 4.1 IN THE COMPANY'S**  
21 **VCM 20/21 REPORT, BASED ON STAFF'S PREFERRED ASSUMPTIONS.**

22 A. The following table contains the results based on Staff's assumptions.  
23

**Table 3**  
**Staff's VCM 20/21 Cost To Complete Economic Evaluation**  
**68-Month Delay Case**  
**Economic Benefit of the Project Versus CC**  
**2018 Net Present Value Date**  
**(Billions of dollars, Negative Means Uneconomic)**

Fuel	\$0/Ton CO <sub>2</sub>	\$10/Ton CO <sub>2</sub>	\$20/Ton CO <sub>2</sub>	Expected Value 1.0
High	1.5	2.0	2.6	
Moderate	0.4	0.9	1.5	
Low	(0.4)	0.1	0.7	

This compares to the Company's expected value result of \$2.2 billion (computed as a 2018 NPV amount) from Table 4.1 of its VCM 20/21 Report.<sup>22</sup> Under current market conditions of low natural gas prices and no CO<sub>2</sub> emissions costs, the analysis indicates it would be economic to cancel Vogtle Units 3 and 4 and build combined cycle units. The Vogtle Units are only marginally economic under moderate gas price and no CO<sub>2</sub> emissions costs; and low gas price and low CO<sub>2</sub> emissions costs. These results are primarily driven by the relatively large amount of remaining capital expenditures and associated financing cost necessary to complete the Vogtle units.

**Q. STAFF'S RESULTS INDICATE IT WOULD BE ECONOMIC TO CONTINUE THE PROJECT. WHY WOULD ONE EXPECT THIS RESULT AT THIS STAGE OF THE PROJECT?**

A. Normally, the closer a project is to completion, the more economic it is on a cost-to-complete basis because more and more of the total project costs are ignored in the analysis and presumably there is less remaining cost to be incurred. In this case, where we are ten

<sup>22</sup> Note that Table 4.1 reports the Vogtle weighted average expected benefit as \$2.8 billion on a 2021 NPV basis. Staff converted it to a 2018 NPV result for purposes of comparison.

years into the Project, it should not be surprising that it appears to be more economic on a cost to complete basis to finish the Project than it would be to abandon the Project and construct a combined cycle unit. What should be noted is how small the benefit of completing the Project is compared to the large amount of sunk costs that are being ignored.

**Q. WHAT ARE THE RESULTS OF STAFF'S DELAY SENSITIVITY ANALYSIS?**

A. If the Project is delayed by 24 months beyond the current forecasted in-service dates, the Project would be uneconomic by about \$0.3 billion. The following table contains the matrix of results for all nine combinations of fuel and carbon dioxide cases.

**Table 4**  
**Staff Cost To Complete Economic Evaluation**  
**92-Month Delay Case**  
**Economic Benefit of the Project Versus CC**  
**August 2018 Net Present Value Date**  
**(Billions of dollars, Negative Means Uneconomic)**

Fuel	\$0/Ton CO <sub>2</sub>	\$10/Ton CO <sub>2</sub>	\$20/Ton CO <sub>2</sub>	Expected Value (0.3)
High	0.1	0.6	1.2	
Moderate	(1.0)	(0.4)	0.1	
Low	(1.7)	(1.2)	(0.6)	

**Q. DID STAFF DETERMINE HOW LONG OF A DELAY IT WOULD TAKE FOR THE PROJECT TO BE UNECONOMIC ON AN EXPECTED VALUE BASIS?**

A. Yes, Staff determined that if the Project were delayed by approximately 18 months beyond the current forecasted in-service dates, it would no longer be economic.

**Q. WHAT WOULD BE THE IMPACT ON STAFF'S COST TO COMPLETE**

---

**ECONOMIC ANALYSIS IF THE COMPANY’S RATHER THAN STAFF’S  
INTERPRETATION OF THE 17<sup>th</sup> VCM ORDER AND SIR STIPULATION WAS  
ASSUMED?**

A. The economic benefit to complete the Project would increase from \$1.0 billion to \$1.1 billion, a change of approximately \$100 million.

**Other Issues**

**Q. DOES STAFF HAVE ANY COMMENTS REGARDING THE COMPANY’S  
REPLACEMENT ENERGY COST AND DEFERRED OPERATING COST  
RESULTS IN TABLE 1.2 OF THE COMPANY’S VCM 20/21 REPORT?**

A. Yes. It appears the Company’s Table 1.2 indicates that over the delay period through June 30, 2019, customers have been harmed by \$103 million based on this calculation.

**Q. DOES STAFF AGREE WITH THE COMPANY’S RESULTS IN TABLE 1.2?**

A. No. The premise behind the table is fundamentally flawed as it ignores the significant additional financing revenue requirements being recovered from ratepayers during the 68-month construction delay period that otherwise would not have been incurred had the Project been completed on-time and on-budget. For the entire delay period through November 2022 ratepayers will pay an additional \$1.8 billion in NCCR revenue requirement during the construction period due to the delays and cost overruns.<sup>23</sup> For a typical residential customer the additional amount collected through the NCCR tariff is

---

<sup>23</sup> The \$1.8 billion value reflects the difference in the current estimate of the NCCR revenue requirement that customers will have to pay, which is \$3.9 billion, and the estimate of \$2.1 billion that would have been paid had the Project been completed in 2016/2017 from the original Certification.

1 approximately \$385 during the construction period.<sup>24</sup> The Company will also recover an  
2 additional \$309 million of financing cost that will be deferred and collected from customers  
3 over the operating life of the Units due to the delays and cost overruns. Finally, Staff  
4 estimates that after the Units go into service, the peak base rate impact for a typical  
5 residential customer will be more than double what the Company told the Commission at  
6 certification. Clearly the delays and cost overruns add additional costs to ratepayers that  
7 are much greater than just the \$103 million shown in Table 1.2

8 **Q. YOU MENTIONED ABOVE THAT THE PURPOSE OF A COST TO COMPLETE**  
9 **ANALYSIS IS TO EXAMINE WHETHER IT WOULD BE ECONOMIC TO**  
10 **FINISH A PROJECT, BUT DOES IT PROVIDE AN INDICATION OF THE**  
11 **TOTAL AMOUNT OF REVENUE REQUIREMENTS CUSTOMERS WILL HAVE**  
12 **TO PAY FOR A PROJECT?**

13 A. No, it does not. As Mr. Hayet has testified in prior VCMs,<sup>25</sup> a life-cycle analysis would  
14 provide additional useful information, including an indication of the total amount of  
15 revenue requirements customers would have to pay for the Vogtle Project. Essentially, the  
16 life-cycle analysis would show what ratepayers would have to pay for Vogtle Units 3 and  
17 4 over the life of the Units versus what ratepayers would have to pay for a combined cycle  
18 unit under various scenarios.

19 **Q. HOW DO THE LIFE CYCLE NOMINAL REVENUE REQUIREMENTS**  
20 **COLLECTED FROM RATEPAYERS COMPARE BETWEEN THE CASE WITH**  
21 **VOGTLE UNITS 3 AND 4 AND THE CASE WITH THE COMBINED CYCLE**  
22 **UNIT?**

---

<sup>24</sup> Staff also estimates that the total amount collected from a typical residential customer during the construction period will be approximately \$833 over the life of the NCCR tariff.

<sup>25</sup> Docket 29849, Philip Hayet Direct Testimony, Eighth VCM Proceeding, pages 19 – 22, and Twelfth VCM Proceeding, pages 29-30.

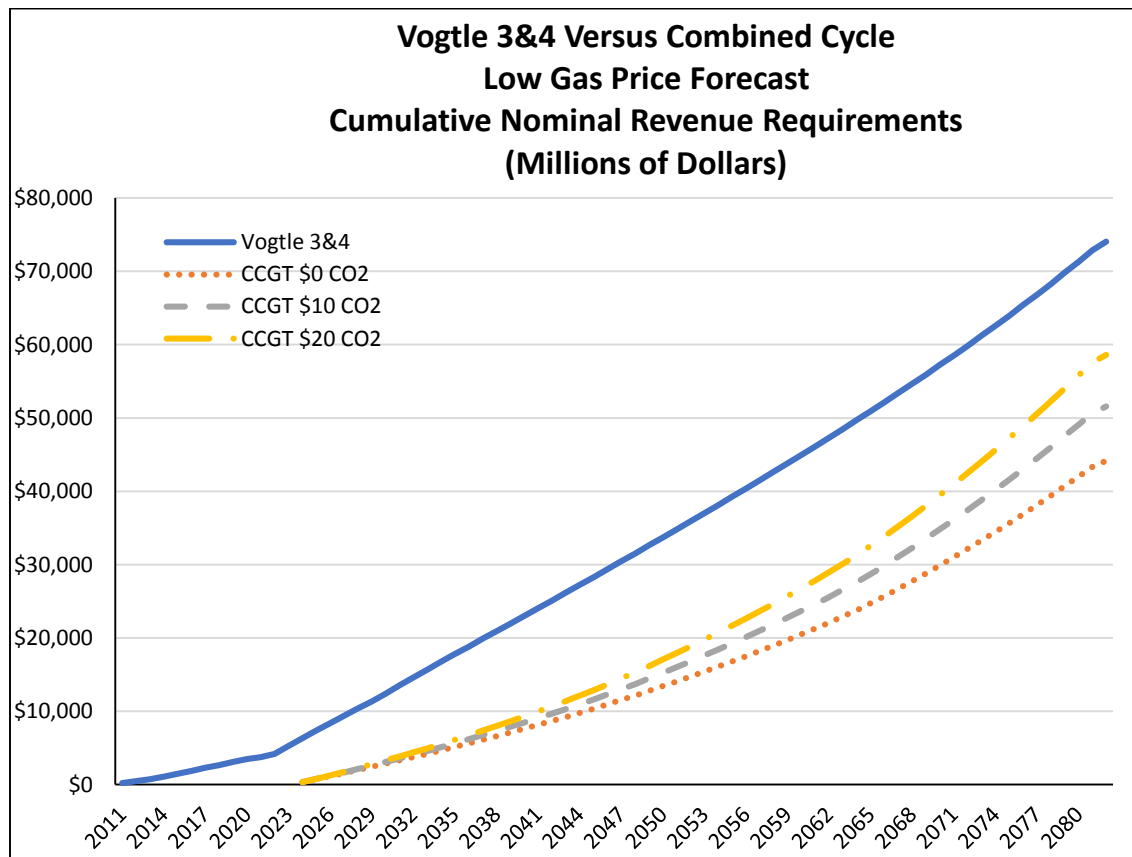
---

1 A. Staff has created a comparison of the projected cumulative nominal revenue requirements  
2 (fuel, O&M, and capital costs) of Vogtle Units 3 and 4 that will be collected from  
3 ratepayers to the replacement combined cycle unit for each of the three natural gas price  
4 forecast scenarios. In the case of the combined cycle unit, Staff added all of the System  
5 replacement fuel and O&M costs to the capital revenue requirements of the replacement  
6 combined cycle unit. Nominal revenue requirements are used in this analysis to indicate  
7 the impact on ratepayer bills.

8 **Q. HOW DOES THE CUMULATIVE NOMINAL REVENUE REQUIREMENT OF**  
9 **VOGTLE 3 & 4 COMPARE TO THE COMBINED CYCLE UNIT ASSUMING A**  
10 **LOW NATURAL GAS PRICE FORECAST UNDER THE THREE CO<sub>2</sub> EMISSION**  
11 **PRICE FORECAST CASES?**

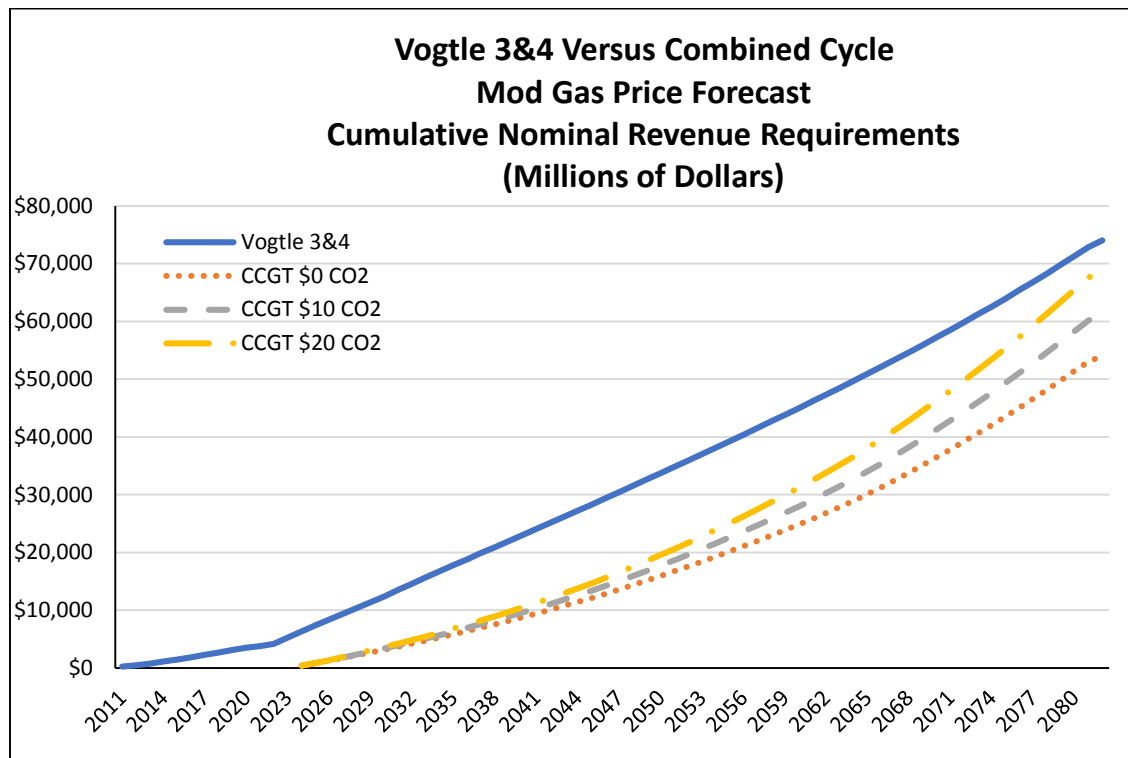
12 A. As indicated in the graph below for the Low Natural Gas price forecast, the Vogtle Units  
13 3 & 4 cumulative nominal revenue requirement exceeds the combined cycle nominal  
14 revenue requirement under all three CO<sub>2</sub> emission price forecasts.





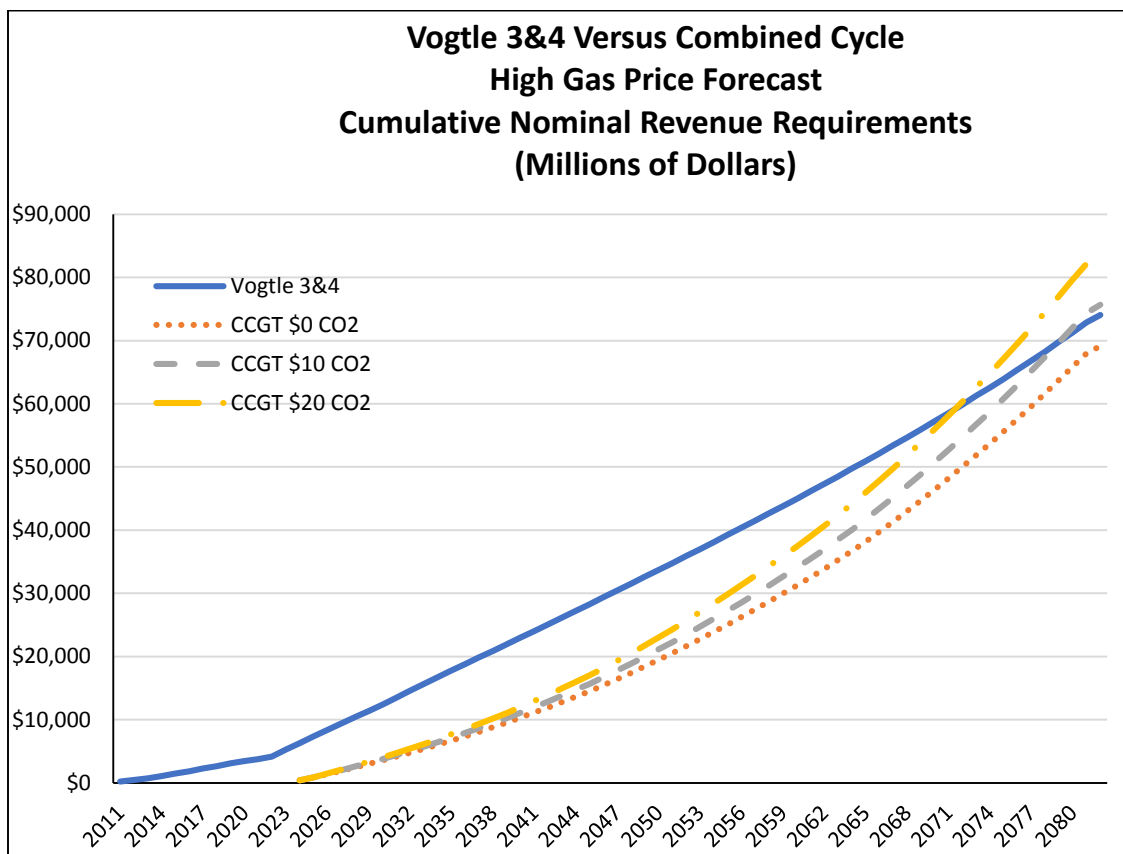
**Q. HOW DOES THE CUMULATIVE NOMINAL REVENUE REQUIREMENT OF VOGTLE 3&4 COMPARE TO THE COMBINED CYCLE UNIT ASSUMING A MODERATE NATURAL GAS PRICE FORECAST UNDER THE THREE CO<sub>2</sub> EMISSION PRICE FORECAST CASES?**

**A.** The Vogtle 3&4 cumulative nominal revenue requirement exceeds the combined cycle nominal revenue requirement under all three CO<sub>2</sub> emission price forecasts.



**Q. HOW DOES THE CUMULATIVE NOMINAL REVENUE REQUIREMENT OF VOGTLE 3&4 COMPARE TO THE COMBINED CYCLE UNIT ASSUMING A HIGH NATURAL GAS PRICE FORECAST UNDER THE THREE CO<sub>2</sub> EMISSION PRICE FORECAST CASES?**

**A.** The Vogtle 3&4 cumulative nominal revenue requirement exceeds the combined cycle nominal revenue requirement under the \$0/Ton case for the entire period, and it exceeds the \$10/Ton CO<sub>2</sub> emission price forecast case almost until the end of the period. Under the \$20/Ton CO<sub>2</sub> emission price forecast, the Vogtle 3&4 cumulative nominal revenue requirement exceeds the combined cycle nominal revenue requirement until 2072.



1  
2  
3 **Q. WHAT WOULD THE RESULTS OF A TRADITIONAL ECONOMIC ANALYSIS**  
4 **USING PRESENT VALUE DOLLAR RESULTS INDICATE?**

5 A. When the life-cycle revenue requirement results are compared on a cumulative present  
6 value basis, the Vogtle Units revenue requirements are greater than the combined cycle  
7 revenue requirements every year in all nine of the natural gas price and CO<sub>2</sub> emission price  
8 cases.

9 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

10 A. Yes, it does.

**BEFORE THE  
GEORGIA PUBLIC SERVICE COMMISSION**

**IN THE MATTER OF: GEORGIA POWER  
COMPANY'S TWENTIETH/TWENTY-  
FIRST SEMI-ANNUAL VOGTLE  
CONSTRUCTION MONITORING REPORT**

**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 Direct 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's 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 thirteen Georgia Power Company ("Company" or "Georgia Power") proceedings before the Commission. Mr. Newsome's most recent testimony was 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 19<sup>th</sup> Vogtle Construction Monitoring ("VCM"), 18<sup>th</sup> VCM and 17<sup>th</sup> 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 17<sup>th</sup> 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 TWENTIETH/TWENTY-  
FIRST SEMI-ANNUAL VOGTLE  
CONSTRUCTION MONITORING REPORT**

**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.

**QUALIFICATIONS OF PHILIP HAYET**

---

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

**1980 to           Energy Management Associates (EMA), Atlanta, GA**  
**1988:           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**

<b>Date</b>	<b>Case</b>	<b>Jurisdict</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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**

---

<b>Date</b>	<b>Case</b>	<b>Jurisdic</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
			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**

<b>Date</b>	<b>Case</b>	<b>Jurisdicit</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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**

---

<b>Date</b>	<b>Case</b>	<b>Jurisdic</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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**

---

<b>Date</b>	<b>Case</b>	<b>Jurisdicit</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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**

<b>Date</b>	<b>Case</b>	<b>Jurisdicit</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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**

<b>Date</b>	<b>Case</b>	<b>Jurisdic</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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**

<b>Date</b>	<b>Case</b>	<b>Jurisdicit</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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**

---

<b>Date</b>	<b>Case</b>	<b>Jurisdicit</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
4/19	42310-U	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power's 2019 IRP Proceeding

**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
- August 2002 – Expert Report, Civil Action No. 1:00-cv-1262 in the United States District Court for the Middle District of North Carolina, United States v. Duke Energy Corporation, Department of Justice

**QUALIFICATIONS OF PHILIP HAYET**

---

- 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 v. 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).

#### **QUALIFICATIONS OF PHILIP HAYET**

---

- 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<sub>2</sub> 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.