**REDACTED**

**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

**In Re:**

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| **GEORGIA POWER COMPANY'S 2025 INTEGRATED RESOURCE PLAN** | ) ) | **DOCKET NO. 56002** |
| **GEORGIA POWER COMPANY'S 2025 APPLICATION FOR THE CERTIFICATION, DECERTIFICATION, AND AMENDED DEMAND-SIDE MANAGEMENT PLAN** | ) ) ) ) | **DOCKET NO. 56003** |

**DIRECT TESTIMONY AND EXHIBITS**

**OF**

**TOM NEWSOME, PE, CFA**

**PHILIP HAYET**

**ANTHONY SANDONATO**

**LEAH WELLBORN**

**ON BEHALF OF THE**

**GEORGIA PUBLIC SERVICE COMMISSION**
**PUBLIC INTEREST ADVOCACY STAFF**

**May 5, 2025**

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## I. BACKGROUND AND QUALIFICATIONS

**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.

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

A. My name is Anthony Sandonato. I am an outside Consultant to Kennedy and Associates. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

A. My name is Leah J. Wellborn. I am Manager of Consulting at 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-NHSW-1, STF-NHSW-2, STF-NHSW-3, and STF-NHSW-4 for Mr. Newsome, Mr. Hayet, Mr. Sandonato, and Ms. Wellborn, respectively.

**Q. HAVE YOU ALL PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. Mr. Newsome, Mr. Hayet, and Ms. Wellborn all previously testified before this Commission, including in the 2022 IRP and the 2023 IRP Update proceedings. This will be Mr. Sandonato's first appearance before the Commission; however, he has testified in other jurisdictions, which are listed in his Exhibit STF-NHSW-3.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

A. We are testifying on behalf of the Commission's Public Interest Advocacy Staff ("Staff").

## II. SUMMARY AND RECOMMENDATIONS

**Q. WHAT ARE THE SPECIFIC ISSUES THAT YOU ADDRESS IN YOUR TESTIMONY?**

A. The issues we address, which are identified in the Conclusion Section of Georgia Power's 2025 IRP Main Document, Executive Summary, beginning at page 4, include:

> *1. The Reserve Margin Study, as provided in Technical Appendix Volume 1, and the Company's recommended System long-term winter Target Reserve Margin value of 26%, long-term summer Target Reserve Margin value of 20%, and the short-term Target Reserve Margins associated with each season.*

> 7. *Extended operation of Plant Scherer Unit 3 and Plant Gaston Units 1-4 and A beyond December 31, 2028, as described in Chapter 8.*
>
> 8. *Certification of wholesale capacity from Plant Scherer Unit 3 to be placed in retail rate base, as specified in Attachment A.*
>
> 9. *Amendment to the certificate at Plant McIntosh Units 10-11 and 1A-8A for incremental capacity, as specified in Attachment B.*
>
> 10. *Approval of incremental capacity at Plant Hatch Units 1-2 and Plant Vogtle Units 1-2, as specified in Chapter 8.*
>
> 11. *The capital and operations and maintenance ("O&M") costs (but not yet the recovery of such costs) the Company will incur for the modernization of Plants Tallulah, Yonah, Lloyd Shoals, Wallace, Bartletts Ferry Units 5-6, Goat Rock, North Highlands, Morgan Falls, and Flint River hydro facilities, as specified in the Hydro Modernization section of Technical Appendix Volume 1.*
>
> 12. *Authority to develop, own, and operate incremental capacity at Plant Goat Rock Units 3-6, as specified in Chapter 8 and the Hydro Modernization section of Technical Appendix Volume 1.*
>
> 14. *The authority to pursue the natural gas co-firing compliance pathway as the 111 GHG Rule strategy for Plant Bowen and Plant Scherer.*

**Q. WHAT RESOURCE PROCUREMENT ACTIONS ARE BEING TAKEN BY THE COMPANY CURRENTLY?**

A. The Company explained its current actions as follows:

> The Company is evaluating the results of the Winter 2027/2028 BESS RFP and the All-Source Capacity RFP for 2029-2031 as well as investigating additional resource options to meet customer needs should these RFPs be insufficient to fill all capacity needs for this period. The Company plans to issue an All-Source Capacity RFP in the third quarter of 2025 to meet its capacity need through 2032 and 2033. The target capacity to be procured through this RFP will be determined based on the Company's capacity needs at the time of RFP issuance, which will be informed by the outcome of this 2025 IRP and the results of the Company's active capacity RFPs.[1]

[1] Main Document, page 77.

**Q. WHAT IS THE POTENTIAL IMPACT OF THE COMMISSION'S DECISION IN THE 2025 IRP ON RATEPAYER REVENUE REQUIREMENTS?**

A. The Company's capital expenditure plan for 2025 – 2029 is quite large and does not include the Company's 2025 IRP requests. The revenue requirement from these capital expenditures is shown in the first column in the table below.[2] The second column provides the revenue requirements from the Company's requests in the 2025 IRP.[3] The third column is Staff's estimate of the revenue requirement of resources selected from the 2029- 2031 All Source RFP based on Staff's load forecast. Together these new additional revenue requirements represent a substantial increase in the Company's 2024 base rate revenue requirement of $7.5 billion. It is important for the Commission to understand the magnitude of the Company's request when reaching a decision in this proceeding.

[2] Capital expenditures are based on Southern Company's 4Q2024 earning call presentation. https://s27.q4cdn.com/273397814/files/doc_financials/2024/q4/SO-2024-Q4-Earnings-Call-Slides-Final.pdf. Staff assumed 70% of State-regulated Electrics investment was for Georgia Power.

[3] Exhibit NHSW-7

**Table 1: Demonstrative Increase in Revenue Requirement 2026-2035** [4]

| | **Revenue Requirement of Company 2025-2029 Expenditures** | **Revenue Requirement of Company 2025 IRP Requests** | **Revenue Requirement From 2029 - 2031 RFP** | **Total** |
|---|---|---|---|---|
| | **(A)** | **(B)** | **(C)** | **A + B + C** |
| Year | ($ million) | ($ million) | ($ million) | ($ million) |
| 2026 | 1,080 | 917 | 0 | 1,997 |
| 2027 | 1,878 | 1,088 | 0 | 2,966 |
| 2028 | 2,582 | 1,245 | 0 | 3,827 |
| 2029 | 3,340 | 1,358 | 0 | 4,698 |
| 2030 | 4,090 | 1,796 | 186 | 6,072 |
| 2031 | 3,980 | 1,917 | 438 | 6,335 |
| 2032 | 3,871 | 1,972 | 999 | 6,842 |
| 2033 | 3,762 | 2,084 | 1,055 | 6,901 |
| 2034 | 3,653 | 2,068 | 1,094 | 6,814 |
| 2035 | 3,543 | 2,045 | 1,064 | 6,653 |

The additional capacity needs and additional costs are being driven primarily by new large load customers. In the 2022 IRP, the Company anticipated retiring significant amounts of coal and oil capacity over the near term, but is now having to make significant investments in existing and new resources to meet projected load. The Company has argued additional revenues will put downward pressure on rates. However, this will only occur if the load materializes, and the load is priced appropriately to fully recover the cost to serve those customers. The Company has not provided any type of guarantee that there will be year-

[4] Revenue Requirements are estimates based on simulations that make certain simplifying assumptions and do not represent the precise revenue requirements ratepayers would pay. These estimates are conservative as O&M and recurring capital investment is not taken into account

over-year downward pressure on rates, and has been vague about whether this will be specifically addressed in the 2025 rate case:

> **Q. So, specifically, does that mean that Georgia Power's customers will start seeing lower power bills in the 2026 to 2028 rate case period?**
>
> A. (Witness Grubb) So, as we mentioned earlier, there's a lot of moving pieces in a rate case. But what we're saying is there is downward pressure from getting more revenues than those costs.[5]

**Q. PLEASE SUMMARIZE THIS PANEL'S FINDINGS AND RECOMMENDATIONS.**

A. Our findings and recommendations are:

1. Staff recommends the Commission direct GPC to perform a revised reserve margin and reliability analysis ahead of the certification of new resources identified in the ongoing 2029-2031 All Source RFP ("AS RFP"),[6] to ensure an appropriate amount of new resources are identified for certification. In the interim Staff recommends use of a winter 24.5% Target Reserve Margin, to account for potential overstatement due to factors such as large load sensitivity to weather, load forecast error, and other issues.

2. Staff recommends the Commission approve the Company's request for continued operations of Plant Gaston 1-4 and A, and Scherer 3 beyond 2028.

3. Due to the changing regulatory environment and the need to mitigate future risk, Staff finds the co-firing pathway for Plant Bowen and Scherer is a reasonable approach to continued operation under 111 GHG Rule regulations at this time. However, Staff recommends the Company minimize entering into new firm natural gas transportation ("FT") commitments, procurements, and construction expenditures related to the co-firing strategy until there is greater clarity on the 111 GHG Rule litigation and the Company's load growth situation.

[5] Georgia Power Direct Testimony Hearing Transcript, Vol. 1, March 25, 2025, p. 571.
[6] https://gpc2029-2031all-sourcerfp.accionpower.com/_gpc_2301/home.asp

4. Staff's analysis indicated the Scherer 3 Wholesale Blocks 1 – 3 were a close call. If the Commission determines to take more capacity than Staff is recommending, then these three blocks should be the first additional resources procured.[7]

5. Staff recommends the Commission approve the Company's request to amend the Certificate of Capacity for the Plant McIntosh Units 10-11 combined cycle ("CC") units, and Plant McIntosh Units 1A - 8A combustion turbine ("CT") units to perform upgrades at the units. Staff further recommends the Commission require the Company to limit cost recovery for these projects to the projected cost estimates presented in this filing. Staff is concerned that these upgrades were not bid in and selected in an RFP process, and recommends the Company be allowed to recover costs on an approved $/kW basis, to ensure the economics are maintained and benefits are passed back to the customers.

6. Staff recommends the Commission approve the Company's request for incremental capacity upgrades at Plant Vogtle Units 1-2, but delay the upgrades at Plant Hatch Units 1-2 to be completed two years after the Vogtle 1-2 upgrades are completed. Staff also recommends the Commission require the Company to limit cost recovery for these projects to the projected cost estimates on an approved $/kW basis, as presented in this filing.

7. Staff finds the generic resource pricing assumptions used in the Company's Resource Mix Study and other evaluations were understated based on current market data and the ongoing RFP results. Staff also finds the Company's Carbon Capture and Storage ("CCS") deployment assumption, and the 20% capacity factor limit applied to CTs were not appropriately justified by the Company in the no 111 GHG price-policy case.

8. The Company performed separate economic evaluations using different data assumptions and models to evaluate resource acquisitions. Staff conducted resource evaluations using consistent data and modeling approach. Staff recommends in the future the Company should adopt an optimal portfolio selection approach in future RFPs.

9. Staff recommends the Commission reject the Company's proposed hydro modernization request, as it is too broad in both cost and scope. Staff recommends the Company be allowed to spend up to $100 million on preliminary investigation and engineering through 2027 on the most economic hydro units remaining to be modernized. With the results of the Company's preliminary investigation and

[7] The Company's MDA adjustment resulted in Block 4 being offered at [redacted]. If the MDA adjustment [redacted] then Block 4 would be a candidate for additional capacity beyond Staff's recommendation.

engineering the Commission would be in a better position in the 2028 IRP to decide how to proceed with hydro modernization.

10. The Company issued the 2029-2031 All-Source Capacity RFP stating, "up to 8,500 MW of Capacity Resources are necessary to satisfy GPC's capacity needs."[8] Based on Staff's evaluation of existing and planned resources, incremental resource additions, an alternative Target Reserve Margin ("TRM"), and an alternative load forecast projection, Staff recommends the Company's 2029-2031 RFP capacity acquisition target be limited to 5,989 MW. By acquiring 5,989 MW as early as 2031, the Company could defer its plan to issue another All-Source Capacity RFP in the Fall of 2025 to a later point in time.[9]

## III. RESOURCE NEED AND RFP TIMELINE

**Q. HOW DID THE COMPANY'S LOAD FORECAST CHANGE BETWEEN THE 2022 IRP, 2023 IRP UPDATE, AND 2025 IRP?**

A. When the 2022 IRP was filed on January 31, 2022, the Company did not anticipate that a significant amount of data center load would be added to the system in future years. One year later the Company's load forecast changed dramatically based on a surge in the number of large-load data centers considering locating in Georgia. As a result of the revised load forecast, the Company filed an updated IRP, the 2023 IRP Update, on October 27, 2023. The Company's load forecast increased even more in the 2025 IRP, again primarily due to data center loads, but also due to increases in some industrial manufacturing. Most of the increase is expected to occur after 2028, as indicated in the following table.

[8] https://psc.ga.gov/search/facts-document/?documentId=219760 Estimated Capacity Need from 2023 IRP for winter 2030/2031 (as noted on page 16).

[9] Table 4b below shows Staff determined that by 2033 the Company's capacity need will be 5,989 MW. Staff recognizes there are significant uncertainties regarding the Company's capacity needs, and also that the Company will continue to have additional capacity needs after 2031. Therefore, Staff recommends using the 2029-2031 All-Source RFP as an opportunity to acquire additional capacity early (up to 5,989 MW by 2031) and defer the Company's next RFP until a later time.

**Table 2: Georgia Power Winter Peak Demand (MW) Forecast Comparison**[10, 11, 12]

| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2022 IRP** | 15,636 | 15,657 | 15,673 | 15,657 | 15,757 | 15,796 | 15,957 | 16,056 | 16,246 | 16,397 | 16,562 |
| **2023 IRP Update** | 15,947 | 17,256 | 18,928 | 19,751 | 20,551 | 21,326 | 21,880 | 22,141 | 22,353 | 22,515 | 22,630 |
| **2025 IRP** | 16,264 | 16,892 | 18,334 | 20,320 | 22,168 | 23,612 | 24,469 | 24,900 | 25,213 | 25,451 | 25,653 |

**Q. WITHOUT CONSIDERING NEW RESOURCES, WHAT IS THE CAPACITY NEED BASED ON THE COMPANY'S 2025 IRP LOAD FORECAST?**

A. The following table presents the Company's view of its 2025 IRP load forecast, and capacity need considering only the resources that were approved prior to the start of the 2025 IRP. The "Total Capacity" column contains all of Georgia Power firm capacity resources, including PPAs with third parties and Demand Side Options ("DSO"), and accounts for resources on an equivalent capacity basis.

[10] STF-JKA-1-3 Attachment A.xlsx.
[11] DKT 44160 2022 IRP Filing, PD B2022 Load and Energy Forecast.pdf, Section 2, p. 14.
[12] DKT 55378 2023 IRP Update Filing, PD Load and Energy Forecast.docx, p.5.

**Table 3: Georgia Power's Winter Load and Resource Balance without Proposed Resources**[13]

| Year | Peak Demand (MW) | Total Capacity (MW) | Capacity Required to Meet GPC Target (MW) | GPC Reserve Margin (%) |
|---|---|---|---|---|
| **2025** | 16,264 | 20,868 | (602) | 28.3% |
| **2026** | 16,892 | 21,829 | (781) | 29.2% |
| **2027** | 18,334 | 23,443 | (598) | 27.9% |
| **2028** | 20,320 | 23,960 | 1,467 | 17.9% |
| **2029** | 22,168 | 22,647 | 5,093 | 2.2% |
| **2030** | 23,612 | 22,757 | 6,790 | -3.6% |
| **2031** | 24,469 | 20,719 | 9,900 | -15.3% |
| **2032** | 24,900 | 20,721 | 10,438 | -16.8% |
| **2033** | 25,213 | 20,668 | 10,881 | -18.0% |
| **2034** | 25,451 | 20,668 | 11,180 | -18.8% |
| **2035** | 25,653 | 19,353 | 12,747 | -24.6% |

The table indicates that as of the start of the 2025 IRP, Georgia Power expected that it would have a need for almost 1,500 MW of additional resources by 2028, and that its need would grow dramatically over time. The table shows that by 2029 its need would increase significantly to over 5,000 MW on a cumulative basis, by 2031 its need would about double to almost 10,000 MW on a cumulative basis, and by 2035 its need would grow to nearly 13,000 MW on a cumulative basis.

In addition to the Company's capacity need being driven by economic development loads, a significant amount of power purchase agreements will expire in the near term,

[13] STF-JKA-1-3 Attachment A.xlsx. Note Georgia Power did account for the assumed 500 MW of resources that it expects to acquire based on the 2022 ESS RFP, which is starting to get underway; however, the Company did not account for the 500 MW of BESS resources that it expects to acquire based on the 2023 BESS RFP that is already underway. Winter months include December-February, and the winter peak 2025 occurred in January 2025

which will exacerbate the Company's need for resources. For example, between 2029-2031, 12 contracts amounting to 3,259 MW will expire, though it is possible those PPAs could be extended through RFP processes.[14]

**Q. BASED ON THE COMPANY'S CAPACITY NEEDS ASSUMPTIONS, WHAT ARE THE COMPANY'S PLANS FOR ACQUIRING NEW RESOURCES IN THE NEAR TERM?**

A. In the 2025 IRP, the Company identified several means of acquiring resources, including actions approved by the Commission in the 2022 IRP and 2023 IRP Update, as well as new actions for which the Company is requesting approval in this IRP. The 2022 IRP and 2023 IRP Update identified actions that the Company is currently working to implement:

> For example, current activities include the addition of more than 2,065 MW of battery energy storage systems ("BESS") and combustion turbine ("CT") resources by the end of 2027, plus the Company's active RFPs for up to 9,500 MW of capacity and more than 3,500 MW of renewable energy resources by the end of 2030.[15]

The Company is currently conducting the 2029-2031 All-Source Capacity RFP that was approved in the 2022 IRP to identify capacity resources. Actions the Company proposes in the 2025 IRP, include upgrading the McIntosh CC and CT units, upgrading the Vogtle 1-2 and Hatch 1-2 nuclear units, continuing to operate the Scherer 3 and Gaston 1-4, and A units beyond 2028,[16] transferring additional Scherer 3 wholesale blocks from wholesale to

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[14] STF-JKA-1-3 Attachment A.
[15] 2025 IRP Main Document, pp. 2-3.
[16] Note that the Company assumed it would continue to operate Scherer and Bowen units through 2035 in its Resource Mix Study and in its Load and Resource Balance tables; however, in the MG0 case in the retirement study, the Company assumed the coal units would operate through 2043.

retail, and modernizing hydro units that will result in adding a small amount of additional capacity. Beyond 2031, the Company proposes to initiate another All-Source Capacity Request for Proposals ("RFP"). That RFP would be issued in the third quarter of 2025 for capacity needs in 2032 and 2033, and it would seek to add up to 4,000 MW of incremental renewable resources to the system by 2035.[17]

**Q. DOES STAFF AGREE WITH THE COMPANY'S LOAD FORECAST?**

A. No. Staff has significant concerns with the Company's load forecast.

**Q. HAS STAFF CONSIDERED ALTERNATIVES FOR THE COMPANY'S LOAD FORECAST, RESERVE MARGIN STUDY AND RESOURCE PLANS?**

A. Yes. Staff's load forecast panel evaluated Georgia Power's load forecast and identified concerns that it addressed by developing alternative Staff load forecasts that were used in Staff's modeling. Our panel reviewed Georgia Power's Reserve Margin Study and identified issues that led to our recommendation for a lower TRM. In our modeling, we used Staff's load forecasts, Staff's TRM, and other changes to assumptions to develop alternative recommendations of how much additional capacity the Company will need to satisfy load requirements, which will be discussed at greater length below.

**Q. HAS STAFF DEVELOPED ALTERNATIVE LOAD AND RESOURCE BALANCE TABLES?**

A. Yes, Exhibit STF-NHSW-5 contains a set of load and resource balance tables, including ones that rely on Staff's preferred alternative load forecast, referred to as the Uniform Load

[17] 2025 IRP Main Document, p. 3.

Realization Model ("Uniform LRM") forecast. Staff's proposed plan reflects the Uniform LRM load forecast and other alternative assumptions Staff has identified, including a revised TRM, alternative assumptions for existing resources, and Staff's recommendation for resources that the Company could acquire to satisfy its resource needs. In addition to these differences in loads and resources, Staff's Energy Efficiency panel also identified approximately 98 MW of thermostat demand response capacity contribution that GPC requested that was not included in the Company's load and resource balance table.[18]

Tables 4a and 4b below show a portion of the information found in Exhibit STF-NHSW-5. Table 4a shows Georgia Power's view of its capacity need position and Table 4b shows Staff's view of Georgia Power's capacity need position for the period 2028 - 2033. The first row in each table shows Georgia Power and Staff's view of Georgia Power's starting position capacity need in the 2025 IRP. The starting positions vary depending on the load forecast, TRM, and resource assumptions assumed in the Company's resource ledger at the start of the 2025 IRP. Georgia Power did not account for the 500 MW BESS RFP that was approved in the 2023 IRP, which is currently underway, while Staff accounted for it in its starting position.

The second row in each table shows Georgia Power's and Staff's view of the near-term incremental resources each party recommends being added to the system. Staff's assumptions differ from the Company's assumptions as indicated in the tables. Specifically, Staff does not include the WTR resources, or the capacity increase associated

[18] STF-JKA-1-3 Attachment A.

with Goat Rock Hydro Modernization project. Also, Staff delayed the timeline for the Hatch 1 and 2 upgrades, by assuming the Hatch 1-2 upgrades should follow completion of the Vogtle 1-2 upgrades by two years. Staff also include an additional 98 MW of Demand Response related to the expanded Thermostat program starting in 2026. Additional discussion of these resources differences is provided below.

The third row in each table shows Georgia Power and Staff's view of Georgia Power's total capacity need after accounting for the incremental resource additions each party recommends being added to the system. Staff's alternative resource decisions are discussed in greater detail below.

**Table 4a: Georgia Power View of Its Capacity Need (MW)**

| Cases | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|
| **Starting Position Capacity Need (MW)** MG0 Load Forecast, 26% TRM, w/o 500 MW BESS[19] | 1,467 | 5,093 | 6,790 | 9,900 | 10,438 | 10,881 |
| **Incremental Additions (MW)** Scherer 3 and Gaston Extended, WTR (blocks 1-4), Upgrades (CT, CCs, Vogtle 1-2, Hatch 1-2, Goat Rock)[20] | 52 | 1,292 | 1,401 | 1,469 | 1,503 | 1,512 |
| **Total Capacity Need Accounting for Near Term Additions (MW)[21]** | 1,415 | 3,801 | 5,389 | 8,431 | 8,936 | 9,369 |

[19] In STF-JKA-1-3 Attachment A. xlsx, the Company did not include the 500 MW BESS RFP resources approved in the 2023 IRP Update Order in its Starting Position.
[20] STF-JKA-1-3 B refers to Georgia Power Territorial Base Case Load vs. Existing Capability Table with 2025 IRP Requests 2-14-25.xlsx. Note, the Company did not account for incremental thermostat demand response as part of the incremental resource additions.
[21] *Id.*

The GPC starting position at the beginning of the 2025 IRP indicates that Georgia Power will need between 9,900 and about 11,000 MWs of capacity resources between 2031 and 2033; however, that requirement is reduced by between about 1,470 MW and 1,500 MW over that period if Georgia Power's proposed requests in the 2025 IRP are approved.

**Table 4b: Staff View of Georgia Power's Resource Need (MW)**

| Cases | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|
| **Starting Position Capacity Need (MW)** Staff Load Forecast, 24.5% TRM, with 500 MW BESS[22] | (773) | 2,292 | 3,628 | 6,551 | 7,004 | 7,386 |
| **Incremental Additions (MW)** Scherer 3 and Gaston Extend, Upgrades (CT, CCs, Vogtle 1-2, Hatch 1-2 delayed), additional Demand Response | 98 | 1,334 | 1,350 | 1,325 | 1,358 | 1,397 |
| **Total Capacity Need Accounting for Near Term Additions (MW)** | (871) | 958 | 2,278 | 5,226 | 5,646 | 5,989 |

The first row of Staff's table (Table 4b) supports Staff's position that the Company's starting position capacity need is much lower than what the Company has determined. Besides a different load forecast assumption, Uniform LRM, and a lower TRM (24.5%), Staff also accounted for 500 MW of additional BESS resources the Company was authorized to acquire in the 2023 IRP Update, based on an RFP the Company is currently conducting. Furthermore, Staff's recommendation for the addition of incremental resources differs from the Company's proposal as follows:

- Staff has left WTR resources out of its load and resource balance tables.
- Staff assumes the Company will upgrade Hatch; however, Staff recommends a two-

[22] STF-JKA-1-3 Attachment A. xlsx, although Staff included the 500 MW BESS RFP resources approved in the 2023 IRP Update Order in its Starting Position.

year delay in the schedule the Company has proposed.

- Staff accounts for an additional 98 MW of demand response on the system.
- Staff does not recommend the Goat Rock capacity upgrade be performed at this time.

Staff's total capacity need accounting for near-term additions (last row) shown in Table 4b indicates the Company will need 5,989 MW of capacity resource by 2033, which is approximately 3,400 MW less than what the Company determined (9,369 MW). Though the Company has stated it plans to issue an All-Source Capacity RFP in the third quarter of 2025, the results in Staff's table above show that if the Company were to acquire as much as 5,989 MW in the currently ongoing 2029-2031 All-Source Capacity RFP, the Company could defer the need for its next RFP until a later point in time.

## IV. STAFF'S REVIEW OF GEORGIA POWER ASSUMPTIONS AND ANALYSES

### Reserve Margin Study

**Q. WHAT IS A RESERVE MARGIN AND HOW DOES IT IMPACT CUSTOMER BILLS?**

A. A reserve margin is the amount of generation capacity, in excess of expected utility peak load, that is required to ensure that a utility can provide reliable service in the event of a loss or disruption of resources or higher than expected loads due to weather events or other factors. From a planning perspective, the higher the TRM the more generation capacity the utility must acquire. While this additional reserve capacity provides reliability to the system, it also has a cost, which will increase customer bills.

As in prior IRPs, Georgia Power performed a study to derive the TRM for the Southern Company System that is both economic and meets the System's reliability targets.

After establishing the System TRM, Southern Company derived the corresponding TRM values that applied to Georgia Power, which were determined by accounting for the diversity of Georgia Power's peak demand compared to the System's peak demand.

**Q. HOW IS THE AMOUNT OF RESERVE CAPACITY DERIVED FROM A RESERVE MARGIN?**

A. As a simple example, assume a utility forecasts it will have a maximum peak demand of 20,000 MW in a given year. If the TRM is set at 20%, then the utility would need a reserve margin of 4,000 MW (20,000 MW x 20%), and its total capacity requirement would be 24,000 MW (20,000 MW + 4,000 MW).

**Q. PLEASE SUMMARIZE STAFF'S FINDINGS AND RECOMMENDATIONS REGARDING THE COMPANY'S 2025 RESERVE MARGIN STUDY?[23]**

A. Staff identified four issues with the Company's 2025 Reserve Margin study that determined the Southern Company winter TRM should be 26% and its summer TRM should be 20%. Staff contends the System's winter TRM is overstated and should be lowered to 24.5%. While these problems focus on the winter TRM, some of the problems would apply equally to the Company's calculation of the summer TRM. However, since the increase of the summer TRM from the current 16.5% level to 20% in this 2025 analysis does not have any material impact on the resource plans of the Company, Staff does not address the Company's proposed 20% summer TRM at this time.

[23] "An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System," January 2025.

Staff believes its recommendation for a winter System TRM of 24.5% is reasonable for use in this IRP.[24] However, Staff's issues, which are discussed further below, should be corrected by the Company by revising its inputs to the SERVM, which was used to perform the Reserve Margin Study.

**Q. DID THE COMPANY RELY ON THE SAME GENERAL METHODOLOGY TO DERIVE SUMMER AND WINTER SEASONAL TARGET RESERVE MARGINS USED IN PRIOR IRPS?**

A. Yes, the Company's recommended winter System TRM of 26% and summer TRM of 20% were based on the same general methodology that has been used in prior IRPs, although certain critical inputs were revised in this study.

In the 2019 IRP, Staff criticized the Company's Load Forecast Error ("LFE") analysis, which produced results that were inconsistent with history, and the Company's Value at Risk ("VaR) calculation, which was developed using a statistical regression analysis. Staff concluded in that IRP that the Company's recommended System 26% TRM in the winter was too high. In the 2022 IRP, Staff again took issue with the Company's LFE probability distribution, and argued that the Company's proposed System's winter 26% TRM was too high. As will be discussed below, the Company modified its LFE distribution methodology another time in this IRP; however, the Company once again

[24] Staff's 24.5% assumption was not developed based on a rerun of the Strategic Energy and Risk Valuation Model ("SERVM") model, as Staff does not have access to the model.

determined 26% should be used as its System TRM, which Staff continues to contend is too high.

**Q. DOES SERVM HAVE THE ABILITY TO CALCULATE THE TRM IN DIFFERENT WAYS?**

A. Yes. SERVM can calculate a TRM based on three different approaches. First, it can calculate a TRM based on an economically optimal reserve margin ("EORM") where it can find the optimal TRM by trading off customer outage, capital addition, and production costs. The EORM is then the reserve margin that produces the minimum value of these components collectively. Second, since SERVM operates using a Monte Carlo probabilistic method and evaluates numerous iterations in determining the expected value result, it can also be used to find the TRM at a higher level of reliability for marginal increases in cost, which the Company refers to as its Value at Risk ("VaR") approach. Third, SERVM can calculate a TRM that meets the requirement that a loss of load event ("LOLE") will not occur more than so many times in a 10-year period, such as one day in 10-years, which is generally recognized as being the industry standard.

In both the 2019 and 2022 IRPs, the Company calculated TRM results based on the EORM and VaR methods, and it also tested to determine if those results would satisfy the 1 day in 10-year LOLE industry standard. The Company found that they would, and therefore, in those IRPs it relied on the EORM and VaR results. However, in this 2025 IRP, the LOLE criterion was not met using either the EORM or VaR methodologies. Therefore, in this IRP, the Company used the TRM that satisfied the 1 day in 10-year LOLE requirement, which resulted in a higher TRM than what was determined based on the EORM or VaR methodologies.

**Q. WHY DOES THE COMPANY AND STAFF FOCUS ON THE WINTER TRM?**

A. As has been the case for a number of years, the winter peak drives the need for generating resources on the Southern Company and Georgia Power Company systems combined. If the system has sufficient capacity resources to meet the requirements of the winter TRM, there will be sufficient, and very likely excess, capacity during the summer months. In the 2025 IRP, the Company has increased the summer TRM to 20% from the previous 16.25%. However, in this IRP, the winter TRM and capacity need still drive the Company's overall system resource requirement.

**Q. WHAT CHANGED IN THE 2025 IRP, WITH REGARD TO THE COMPANY'S DEVELOPMENT OF THE WINTER TRM?**

A. While the Company's 2025 IRP Reserve Margin Study used different data assumptions and some different methodologies compared to prior Reserve Margin Studies, the latest study resulted in the same recommendation for a winter TRM of 26% as the Company recommended in prior IRPs. The most important change in this study, as mentioned above, is that the 26% System winter TRM has now been determined based on the goal of meeting the 1 day in 10-year industry standard LOLE requirement. The SERVM analysis showed that a winter TRM of 25.75% would be required to meet the 1 day in 10-year LOLE criterion. The Company rounded this up to 26%. Table 5 below shows the Company's proposed winter TRMs calculated for each of the three methodologies. The LOLE numbers represent the number of years that are expected to occur between loss of load events. Any value less than 10 years does not satisfy the 1 day in 10-year reliability standard.

**Table 5: Georgia Power Company's Proposed Winter Target Reserve Margins**

| TRM Derivation Methodology | RM | LOLE |
|---|---|---|
| EORM | 22.75% | 6.9490 |
| VaR | 25.00% | 9.3197 |
| LOLE (1 day in 10 Years) | 25.75% | 10.3369 |

**Q. WHAT EXPLANATION DID THE COMPANY GIVE FOR THE FACT THAT THE EORM AND VAR APPROACHES NOW PRODUCE LOWER TRM RESULTS THAN THE 1 DAY IN 10-YEAR LOLE METHODOLOGY?**

A. The Company explained that the load troughs in the Company's load forecast have narrowed. Since there are more hours during cold weather periods of higher loads, the potential for loss of load increases and the winter TRM based on the EORM/VaR calculation is now lower than the TRM based on the LOLE calculation.

**Q. HAS STAFF IDENTIFIED ANY PROBLEMS WITH THE COMPANY'S 2025 RESERVE MARGIN ANALYSIS?**

A. Yes. As mentioned above, SERVM uses a Monte Carlo simulation approach to develop a probabilistic analysis of the impact of a number of factors that affect both the EORM and LOLE.[25] Georgia Power included the following key inputs in the simulation:

- 50 years of weather history in the Southern Company system, covering 1973 to 2022.
- A load forecast for the Southern Company system for the SERVM base year of

[25] The VaR result are derived from EORM results, so SERVM only produces alternative values in the EORM and LOLE calculations.

2028.[26]

- Generating unit forced outage rates.
- The cost of customer outages.
- The availability of emergency imports from neighboring utility systems.
- The effect of low temperatures on forced outages and,
- A distribution of load forecast error assumptions ("LFE").

The Staff has identified four issues of concern with the Company's analysis that impact both the EORM/VaR and the LOLE calculations and resulted in an overstatement of the Company's TRM. These issues are briefly described here and discussed in greater detail below:

1. ***Load Forecast Error ("LFE") Distribution:*** This issue can be summarized by the fact that the Company's LFE methodology significantly increased the LFE adjustment factors, which in turn increased the TRM under both the EORM calculation and the LOLE calculation. The LFE distribution is a probability distribution that was developed by the Company to adjust the 2028 load forecast for assumed forecast errors, either understatement or overstatement of the forecast.[27] The Company's determination of the LFE distribution was overstated because the 2025 Reserve Margin Study included both statistical model errors produced by its load forecasting equations and economic driver forecast errors (for example, Gross Domestic Product ("GDP")). In addition, the Company did not adjust the economic uncertainty values to reflect the fact that there is not a one-

[26] The SERVM analysis is performed on a total Southern Company basis, not on a Georgia Power Company basis.

[27] See page 15 of the Company's 2025 Reserve Margin Study for the LFE distribution that adjust the weather adjusted 2028 load forecast. SERVM simulates this LFE distribution by multiplying the weather year adjusted hourly loads for 2028 by factors that both increase and decrease the forecast.

for-one relationship between load and macro-economic drivers, such as Gross Domestic Product ("GDP"). The Company's LFE methodology significantly increased the LFE adjustment factors, which in turn increased the TRM under both the EORM calculation and the LOLE calculation.

2. ***Data Center Load Sensitivity to Weather and Forecasted Load Growth:*** The Company's data center load assumptions contributed to an overstatement of the Company's winter TRM. The overstatement stemmed from the weather modeling approach the Company used to adjust the base year load forecast. The same weather adjustments were applied to the entirety of the load forecast even though large data center loads are much less weather sensitive and should have received a different (lower) adjustment to accurately reflect their impact on the system in the winter.

3. ***Cold Weather Data Training Model:*** As mentioned, the Company's SERVM modeling approach adjusted the 2028 base-year weather normalized load forecast for each of the 50 weather year histories. As part of the modeling process, the Company developed statistical regression models (so-called "training models") using recent system load and weather data to derive a relationship between load and weather. The estimated statistical coefficients from these training models were then used to adjust the 2028 load forecast, which is based on normal weather, to a corresponding 2028 load forecast reflecting weather conditions in each of the 50-year history. In order to develop the coefficients, it was necessary to estimate the

regression models using recent data.[28] The Company used 2018 – 2022 data for this purpose.

Staff's concern is that there was little history of extremely low temperatures in the 2018 – 2022 period that was used to develop the training models. For example, the training model database consisted of over 35,040 hours of weather data for the period 2018 to 2022.[29] During that period, there were only 47 hours in which the temperature fell below 20 degrees and no hours when the temperature was below 10 degrees. Yet, the regression equations that were derived in the training model development process were applied to the 50 weather years data that included years with historically low temperatures that occurred in the 1980's (the low temperature in January 1985 was -3 degrees). As a result, Staff is concerned that the weather adjusted loads for certain extremely low temperature conditions were overstated, and therefore, the LOLE and winter TRM were both overstated.

4. ***Model Sensitivity and Single Cold Weather Month:*** Staff is concerned by the magnitude of the impact that just a couple of months of extremely low temperatures had on the overall LOLE and winter TRM, which reinforced Staff's concern that the system 26% winter TRM was overstated. As will be discussed more below, simply removing the effects of the weather that occurred in the single month of

[28] Estimating the relationship between a change in temperature and a change in load requires that the data set reflect relationships consistent with the 2028 base year. In order to properly adjust the 2028 forecast for alternative weather histories, the statistical model must be estimated using a more recent set of data, not data for the entire 50-year period, to accurately reflect the mix of customers (residential, commercial, industrial), appliance saturation, appliance energy efficiency (e.g., heat pump efficiency), and weatherization in 2028.

[29] Four years of hourly data (4 x 8760 = 35,040). The Company eliminated 2020 to exclude COVID impacts.

January 1985 (one month out of a total of 50 years of weather – 600 months) reduces the winter TRM to less than 24% from the Company's 26%. This result is indicative of the sensitivity of the SERVM results to extreme winter weather.

<u>Load Forecast Error Distribution</u>

**Q. WOULD YOU EXPLAIN FURTHER STAFF'S CONCERN REGARDING THE LFE DISTRIBUTION IN THE COMPANY'S 2025 RESERVE MARGIN STUDY?**

A. As discussed above, the SERVM analysis relied on a Monte Carlo simulation that incorporated probability distributions in the determination of system loads, generating unit forced outage rates, the effect of 50 years of weather history (1973 to 2022), the effect of extreme cold weather on generating unit forced outages, and uncertainty associated with the ability of neighboring utilities to transmit emergency power to the Southern Company system across tie lines.

The Company developed the LFE probability distribution based on an ad hoc approach to reflect uncertainty in the 2028 weather normalized Southern Company load forecast. As mentioned earlier, the Company has repeatedly changed its methodology to calculate the LFE distribution. In this 2025 Reserve Margin study, the Company once again revised its LFE methodology.

**Q. PLEASE DESCRIBE THE LFE METHODOLOGY THE COMPANY DEVELOPED FOR THIS CURRENT RESERVE MARGIN STUDY.**

A. In this 2025 IRP, the Company combined two sources of potential error to determine the LFE distribution, which are: 1) load forecast model statistical error and 2) a measure of economic uncertainty based on the high and low macroeconomic forecast produced by the

Energy Information Administration ("EIA") in its Annual Energy Outlook ("AEO") forecast. The LFE distribution used by the Company in this current analysis is shown below.

**Table 6: Georgia Power Company Proposed Load Forecast Error Distribution**

| | | Low | Med | High |
|---|---|---|---|---|
| **Economic Scenarios from EIA** | Error % | -2.38% | 0.00% | 1.42% |
| | Probability | 33.33% | 33.33% | 33.33% |
| **Model Error** | Error % | -3.74% | 0.00% | 3.74% |
| | Probability | 33.33% | 33.63% | 33.04% |

Table 7 shows the LFE distribution (combined Economic and model uncertainty) that is used in SERVM.

**Table 7: Final Consolidated Load Forecast Error Distribution**

| **LFE** | -6.12% | -3.06% | -0.32% | 2.58% | 5.16% |
|---|---|---|---|---|---|
| **Probability** | 11.11% | 22.32% | 33.33% | 33.33% | 11.01% |
| **SERVM Load Multiplier** | 0.9388 | 0.9694 | 0.9968 | 1.0258 | 1.0516 |

Based on the LFE distribution used by the Company, some of the Monte Carlo simulations reflected an increase in the 2028 weather normalized peak load forecast of 5.2%.[30] Under these simulations, the LOLE increased significantly because the calculated peak load increased by 5.2%. In addition, for years, such as 1985, this load forecast

[30] The Company's SERVM analysis was based on simulations that were performed considering 50 weather years, two alternative start days (Tuesday or Saturday), 11 winter reserve margins, and 5 LFE factors that formed the LFE distribution. The total number of simulations produced was 5,500 for each month, yielding a total of 66,000 monthly outputs (50 X 2 X 11 X 5 = 5,500. 5,500 X 12 = 66,000). Therefore, 13,200 monthly results were based on the 5.2% LFE factor.

adjustment is further exacerbated by the extreme low temperature adjustment using the training models.

**Q. DOES THE STAFF AGREE WITH THE COMPANY'S NEW LFE METHODOLOGY?**

A. No. Staff disagrees with the calculation of the Company's LFE distribution. The LFE distribution should be limited to the effect of the uncertainty associated with the economic drivers of the forecast (i.e., the uncertainty associated with the economy in general) and should not include an additional model error component. The Company developed a model error component based on a regression analysis that derived a statistical error residual distribution, in which load was the independent variable. Since the load forecast was the independent variable used in the derivation of the LFE distribution and given that the load forecast depends on many variables such as economic activity or GDP, weather, number of customers/population, etc., the potential for error in the load forecast can be very large. The fact the Company included forecast model statistical error simply expanded the LFE distribution and overstated the TRM calculation.

**Q. OTHER THAN THE PROBLEM WITH THE MODEL ERROR COMPONENT, DID STAFF IDENTIFY ANY OTHER PROBLEMS WITH THE COMPANY'S LFE DISTRIBUTION?**

A. Yes. In the 2019 IRP reserve margin analysis, in which the Company only used an LFE distribution based on economic uncertainty, the economic errors were adjusted by a factor of [redacted] to reflect the fact that there is not a one-for-one relationship between Southern

Company' load growth and economic growth. In this IRP, the Company did not include a similar adjustment, which Staff is concerned about.

**Q. HAVE YOU SEEN OTHER RESERVE MARGIN STUDIES THAT INCLUDED A SIMILAR ADJUSTMENT.**

A. Yes. We have reviewed reserve margin studies for four different utilities as part of consulting work performed on behalf of the South Carolina Office of Regulatory Staff ("ORS"). These included Duke Energy Carolinas, Duke Energy Progress, Dominion South Carolina and Sante Cooper reserve margin studies. All of these studies were performed by Astrapé on behalf of the utilities using its SERVM model.

**Q. HOW DID ASTRAPÉ CALCULATE ITS LFE DISTRIBUTION?**

A. Like the Company in its 2019 IRP Reserve Margin Study, Astrapé calculated the LFE distribution using an estimate of the potential forecast error caused solely by the impact of economic activity (GDP). In other words, Astrapé did not also include a forecast model error component in addition to the economic activity component that it used to calculate the LFE Distribution. Also, Astrapé recognized that an error in economic activity would not result in one-to-one error in the peak load forecast itself. In other words, a 1% change in the economic input factor would not generally result in a corresponding 1% change in the peak load forecast. Astrapé estimated that only 40% of the economic forecast error would impact the utility's peak load forecast. While this is higher than the [redacted] adjustment factor used by the Company in its 2019 Reserve Margin Study, Astrapé's 40% LFE distribution adjustment is much lower than what the Company is assuming by applying no adjustment in the 2025 IRP. Staff believes a 40% adjustment factor is a reasonable basis to adjust the economic uncertainty percentages in this 2025 Reserve Margin Study.

**Q. HAVE YOU ESTIMATED THE IMPACT OF USING AN LFE DISTRIBUTION THAT ADDRESSES STAFF'S TWO LFE DISTRIBUTION CONCERNS?**

A. Yes. The Staff revised the Company's LFE distribution by eliminating the model error component and adjusting the remaining economic components that were calculated by the Company using a factor of 40% to reduce the economic uncertainty factors developed by the Company, consistent with the Astrapé approach. The resulting LFE is shown in Table 8 below.

**Table 8**
**Staff Recommended Load Forecast Error Distribution**

| | | Low | Med | High |
|---|---|---|---|---|
| **Economic Scenarios from EIA** | Error % | -0.95% | 0.00% | 0.57% |
| | Probability | 33.3% | 33.3% | 33.3% |

| | | | | |
|---|---|---|---|---|
| **Model Error** | Error % | 0.00% | 0.00% | 0.00% |
| | Probability | 33.3% | 33.6% | 33.0% |

**Q. DID THE STAFF ATTEMPT TO ESTIMATE THE IMPACT ON THE WINTER TRM USING THE STAFF ADJUSTED LFE DISTRIBUTION SHOWN IN TABLE 8?**

A. Yes. While Staff does not have access to SERVM, we were able to develop an approximation of the SERVM results by using the Company's LFE distribution and interpolating the LOLE results for each reserve margin case to reflect the revised LFE factors. Applying these alternative LFE multiplier weights to the Company's SERVM output produced a winter TRM of 24.6%.

Data Center Load Impact Issue

**Q. PLEASE DISCUSS THE SECOND ISSUE THAT YOU HAVE IDENTIFIED REGARDING THE COMPANY'S 2025 RESERVE MARGIN STUDY?**

A. The Company's SERVM TRM analysis was based on a single base year, 2028. The analysis started with a weather normalized hourly load forecast for 2028 (B2024 forecast), and, using Monte Carlo simulation, adjustments were applied to the 2028 load forecast to reflect load changes that were estimated to occur under each of the alternative weather year conditions. In the 2025 study, 50 weather years for the period 1973 to 2022 were simulated by adjusting the 2028 normalized load forecast. Each of the 50 weather years was simulated to determine the impact on production costs, emergency imports, forced outage rates due to low temperatures and system loads. However, since the 2028 base year load forecast contained thousands of MWs of large customer load additions (primarily data center loads) that are not very sensitive to winter temperatures, the SERVM Monte Carlo analysis overstated the impact on estimated system loads under low temperature weather conditions during the winter months.

As an example, in January 1985, winter temperatures reached minus 3 degrees in the Southern Company service area. In SERVM, this resulted in an increase in the otherwise applicable 2028 weather normalized load forecast as heating load substantially increased on the system. However, to the extent that data center load is included in the 2028 forecast, this load was also adjusted upwards to reflect the extreme low winter temperatures. While data center load may be impacted by extreme hot temperatures in the summer, it is less impacted by low temperatures in the winter. This upwards adjustment in the winter resulted in an increase in the system load that was simulated and impacted the resulting LOLE. This had the effect of overstating the SERVM calculated winter TRM.

Cold Weather Data Training Model

**Q. PLEASE DISCUSS THE PROBLEM WITH THE COMPANY'S LOAD/WEATHER REGRESSION "TRAINING MODELS" THAT STAFF IDENTIFIED.**

A. This issue concerns the so-called training models developed by the Company for the 2025 Reserve Margin Study that were used to adjust the weather normalized base case (B2024) load forecast for the effects of alternative weather year data. In the Company's study it chose 2028 as the base year load forecast for the training model derivation. As discussed previously, the Company's SERVM model adjusted the base case load forecast for 50 different years of actual weather experience in the Southern Company service area. To make adjustments to the 2028 weather normalized load forecast, SERVM relied on regression models that developed relationships between load and weather. These models were estimated using data for the period 2018 through 2022, though 2020 was excluded to minimize impacts related to the COVID-19 pandemic.[31] Separate linear regression models were created for different temperature ranges. One of the statistical models was estimated

[31] Georgia Power response to STF-JKA-5-1.

using data for hours when the weighted average of five weather stations across the Southern Company territory was below 36 degrees. This model was used to adjust the 2028 load forecast for weather conditions on extremely cold days, such as occurred in 1985.

**Q. WHAT WAS THE SPECIFIC PROBLEM THAT STAFF IDENTIFIED WITH THIS LINEAR REGRESSION MODEL USED IN THE TRAINING DATA?**

A. This low temperature training model had 1,225 observations in which the temperature was less than 36 degrees during the period 2018 to 2022. The problem is that of these 1,225 observations from the 2018 to 2022 period used to estimate the statistical model, there were only 47 hours in which the temperature was less than 20 degrees, and no hours in which the temperature was less than 10 degrees.[32]

The issue is whether a model that relates load to weather (the training model) that is estimated using a period that does not include very low temperatures can produce adjustment factors (coefficients) that can accurately be used to adjust the 2028 load forecast for weather conditions that did not exist in the time period used to estimate the model. In particular, as winter temperatures approach 10 to 15 degrees, it would be reasonable to assume that space heating load would be fully operational. Further drops in temperature may not change the space heating load on the system significantly. In fact, at extremely low temperatures, some commercial or industrial load may not be operational (perhaps schools, for example). The regression equations derived from the training model would not lead to accurate calculations of load when weather year data, which includes much colder

[32] See response to Staff -JKA-5-1, Attachment C Trade Secret.

temperatures, are applied to the regression equations. Particularly, the weather year data from weather profiles that occurred in the 1980s that had very low temperatures would result in an overstatement of the calculated load, LOLE, and in turn the ultimate winter TRM.

Model Sensitivity and Cold Weather Months

**Q. WHAT IS THE STAFF'S CONCERN REGARDING THE IMPACT OF A FEW VERY LOW TEMPERATURES IN THE CALCULATION OF THE WINTER TRM?**

A. This issue concerns the impact of just a very few cold weather months on the SERVM calculation. A review of the weighted average Southern Company weather data for the 50-years history used in the 2025 Reserve Margin Study (1973 to 2022) shows that there were only 3 years when the minimum temperature fell below 5 degrees, and all of these years were in the 1980's (1982, 1983 and 1985). These years had a disproportionately large impact on the resulting winter TRM produced by the SERVM analysis.

**Q. WHAT IS THE BASIS FOR THE CONCLUSION THAT JUST A FEW YEARS (ACTUALLY ONE COLD WEATHER MONTH) OF VERY LOW TEMPERATURE DATA IN THE WEATHER HISTORY HAS A SIGNIFICANT IMPACT ON THE WINTER TRM RESULTS?**

A. To measure the impact on the calculation of the winter TRM, the Staff recalculated the winter TRM using the Company's monthly base case SERVM output file. This file contained monthly Monte Carlo simulation results for 50 years, two different annual start days (Tuesday and Saturday start days), 11 different reserve margin scenarios and each of the 5 LFE distribution factors. This SERVM output file reflected 600 months of weather history (50 years X 12 months). The Staff then eliminated the effect of a single month of weather history (January 1985) from the SERVM output file and re-weighted the remaining scenarios that included 599 months of weather history (600 months less the month of January 1985).

**Q. WHAT ARE THE RESULTS OF THE ANALYSIS?**

A. Table 9 below shows the resulting winter TRM using all of the Company's assumptions except for the elimination of January 1985 weather from the calculation of the winter TRM. The winter TRM was calculated for each of the Company's methodologies (EORM, VaR and LOLE).

**Table 9: Winter Target Reserve Margins Excluding January 1985 Weather**

| TRM Derivation Methodology | RM | LOLE |
|---|---|---|
| EORM | 22.25% | 8.9 |
| VaR | 24.75% | 13.3 |
| LOLE (1 day in 10 Years) | 23.25% | 10.4 |

As Table 9 shows, simply removing a single month of weather history (January 1985) from the 50-year data set (600 months of weather data) resulted in the winter TRM dropping to 23.25% from the Company's 25.75%, based on LOLE. However, as shown in the table, the winter TRM using the Company's VaR construct now becomes greater than the LOLE based result. As such, following the Company's protocol, the winter TRM would be 24.75%, if the January 1985 weather history was excluded.

**Q. WHY DID THIS SIGNIFICANT REDUCTION IN THE WINTER TRM OCCUR?**

A. Based on a review of the monthly SERVM outputs, a substantial portion of the loss of load in the winter season occurs when temperatures are at the extreme lows. The surprising thing is how sensitive the SERVM based TRM results are to a single month out of 600. To help put this into perspective, Staff did a simple comparison of the January 1985 load calculated by SERVM versus the January 2022 load (a much milder winter temperature month) calculated by SERVM. The calculation for both months (January 1985 and January 2022) was based on using the smallest LFE multiplier simulated by the Company (an adjustment of -0.32%) and assuming a Tuesday start day. The SERVM output using the January 1985 weather month versus January 2022 is summarized in the table below.

**Table 10**
**January 1985 Weather vs. January 2022 Weather Impact on Load**

| | MWH Load | Monthly Unweighted LOLE |
|---|---|---|
| **Jan 2022 Weather, -0.32 LFE, 26% RM** | 19,527,374 | 0 |
| **Jan 1985 Weather, -0.32 LFE, 26% RM** | 21,122,329 | 2 |
| **Percent Difference** | 8.2% | |

The results indicate that the energy difference for the two January months amounts to an 8.2% difference. This increase in energy for January 1985 resulted in a significant LOLE for the month of 2.0, compared to a LOLE calculation for January 2022 of 0.0.

**Q. WOULDN'T YOU EXPECT THIS OVERSTATEMENT OF LOLE DUE TO LOW TEMPERATURE WEATHER YEARS TO BE OFFSET BY LOLE'S COMPUTED USING WARMER THAN NORMAL WINTER TEMPERATURE WEATHER YEARS?**

A. No. In the case of a "warmer than normal" winter temperature weather year, the LOLE would be limited to reaching 0.0 but could never be driven below zero in the calculations. So, in the case of simulations with a high LFE forecast adjustment factor, and comparing a case with a normal winter weather year to a case with a very cold winter weather year (e.g. 1985), the case with the very cold winter weather would result in a much higher LOLE value than the other case. However, the opposite could not occur when a warm winter weather year is simulated. In other words, in the case of simulations with a low LFE forecast adjustment factor, and comparing a case with a normal winter weather year that results in 0.0 LOLE to a case with a very warm winter weather year, the case with the very warm winter weather year could not result in an even lower LOLE value given that the normal winter weather year case already was at an LOLE value of 0.0 and could not go any lower. As a result, the effect of warmer than normal winter weather years would not offset the problems with the colder than normal winter weather years. Therefore, the results are biased in one direction.

**Q. IS STAFF SUGGESTING THAT THE LOW TEMPERATURES THAT OCCURRED IN THE SOUTHERN COMPANY SERVICE AREA IN JANUARY 1985 COULD NEVER HAPPEN AGAIN?**

A. No. It simply shows that the SERVM analysis is significantly dependent on the impact of a single month of weather history, if it includes extreme temperatures. For example, if the SERVM analysis was performed using 30 of the more recent years of weather data instead of the 50 weather years, which is actually the number of years the National Oceanic and Atmospheric Administration ("NOAA") uses in weather normalization calculations it performs,[33] the LOLE methodology would derive a TRM of less than 20%.[34] However, in this case, using 30-year weather history, the VaR based winter TRM methodology would produce a higher result, a TRM of 24%. The TRM results for this case are summarized as follows:

**Table 11: Winter TRMs Using 30 Years of Weather Data**

| TRM Derivation Methodology | RM |
|---|---|
| EORM | 22.75% |
| VaR | 24.00% |
| LOLE (1 day in 10 Years) | <20% |

Staff's recommended 24.5% TRM is higher than the VaR based TRM derived in this analysis.

**Q. BASED ON THE STAFF'S ANALYSIS, WHAT IS THE STAFF'S RECOMMENDATION FOR A WINTER TRM?**

A. Staff recommends that the Commission authorize the Company to use a winter TRM of 24.5% for resource planning purposes. Staff has shown that in numerous ways, the Company has overstated its TRM, and Staff believes that a 24.5% TRM is conservative and would provide necessary reliability for the Southern Company system and would not burden customers with excess costs. Staff also recommends the Commission direct the Company to perform a revised reserve margin analysis using the adjustments Staff identified ahead of the certification of new resources identified in the ongoing 2029-2031

[33] https://www.ncei.noaa.gov/products/land-based-station/us-climate-normals

[34] The Company's SERVM analysis does not evaluate reserve margins below 20% in the winter TRM calculation. However, performing this analysis based on the most recent 30 years of weather would derive an LOLE based RM that would be less than 20%.

All Source RFP to ensure an appropriate amount of new resources are identified for certification.

**Resource Mix Study**

**Q. WHAT WAS THE PURPOSE OF GEORGIA POWER'S RESOURCE MIX STUDY?**

A. The Company performed its Resource Mix Study to develop a long-term resource addition schedule to provide "an informative roadmap for long-term decisions."[35] The Company performed the study using its Aurora optimization model that considered the status of its existing system, forecasts of peak demand and energy, and estimates of fuel prices and carbon dioxide ("$CO_2$") emissions costs. Based on the System's 26% TRM, Aurora determined when new resources were needed, and it considered generic resource alternatives, including conventional resources, renewable resources, and demand-side options.[36] The Company stated that the scenarios considered in the Resource Mix study do not "represent commitments but instead provide generic expansion plans used for planning and to support analyses."[37] Staff has certain concerns with the Company's Resource Mix Study discussed below.

**Q. WHAT ASPECTS OF THE RESOURCE MIX STUDY DID YOU EXAMINE?**

A. Primarily, we evaluated Georgia Power's input assumptions and output results.

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[35] 2025 IRP Resource Mix Study TRADE SECRET.docx, pg. 1.

[36] The Company performed a "supply-side case" in Aurora that considered incremental energy efficiency and demand response programs as resource options in the context of the DSM evaluation. The Company's mix study did not include incremental Demand side options, but did include existing demand response in the system modeling.

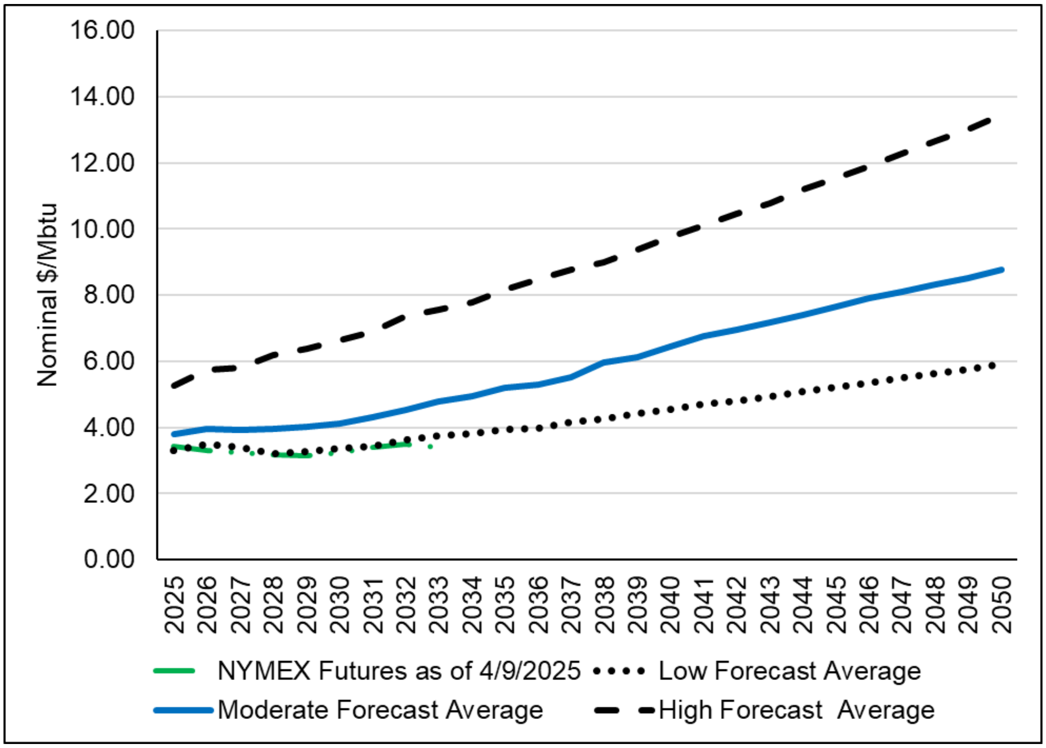
[37] I*d.* at pg. 1.

<u>Fuel and Carbon Forecast</u>

**Q. PLEASE DISCUSS YOUR EVALUATION OF THE COMPANY'S NATURAL GAS PRICE FORECAST?**

A. Staff reviewed the Company's latest natural gas price forecasts, B2025, used in various studies in the IRP, including the Resource Mix Study, and compared them to other publicly available, recently published gas price forecasts. Staff developed Low, Moderate, and High gas price forecasts by averaging the publicly available data. The following graphs show Staff's Low, Moderate, and High Henry Hub forecasts, plus the April 9, 2025 NYMEX forecast.

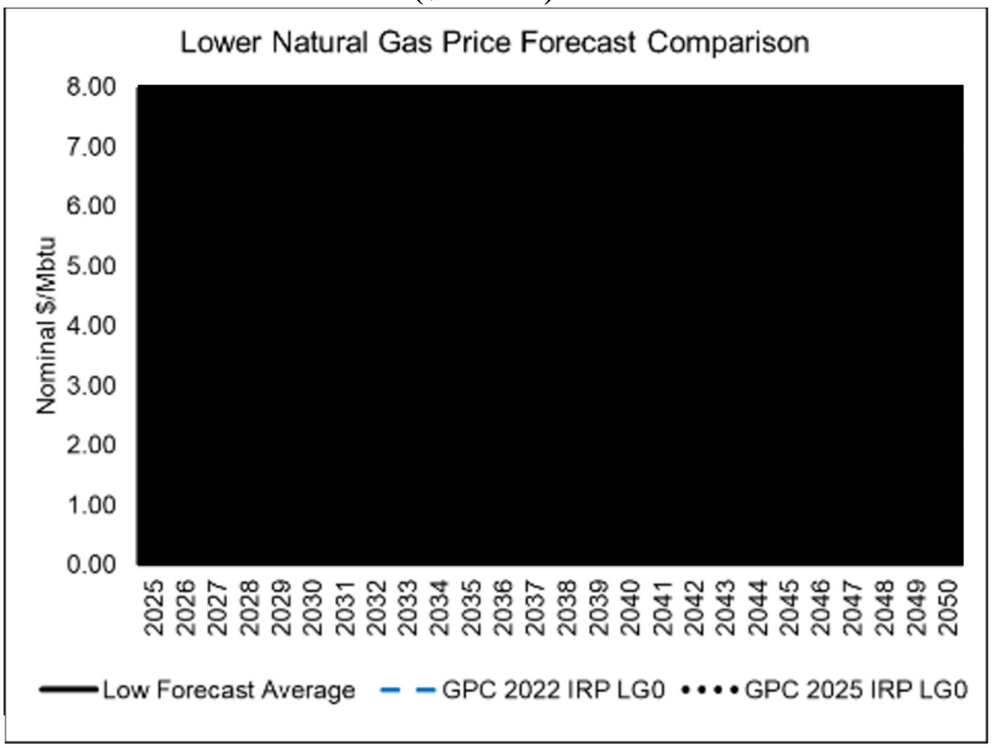
**Figure 1: Staff Average Gas Price Forecasts ($/MBTU)[38]**




The following graphs compare the Company's natural gas price forecasts to the average forecasts Staff derived from publicly available forecasts. Separate graphs are shown for the Low, Moderate, and High Henry Hub forecasts.

[38] Publicly Available sources include Duke Indiana 2024 IRP, Dominion Energy South Carolina 2025 IRP Update, Santee Cooper 2024 IRP Update, PacifiCorp 2025 IRP, Tennessee Valley Authority Draft 2025 IRP, AVISTA 2025 IRP, NYMEX Futures, Entergy NOLA 2024 IRP, and Indiana Michigan Power Company 2024 IRP.

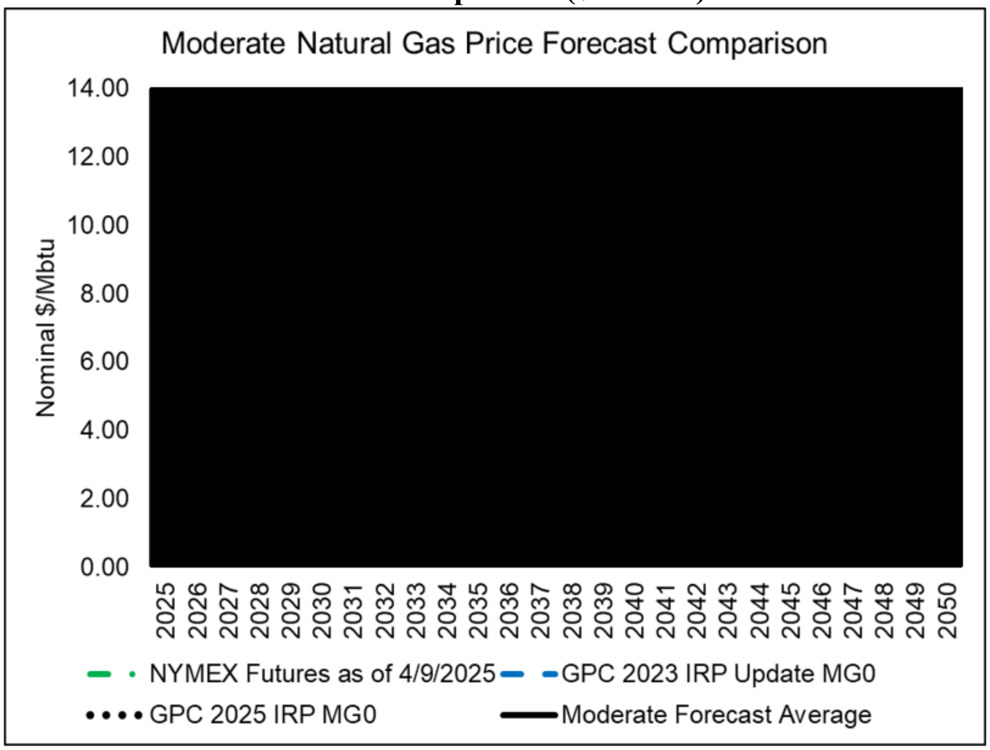
**Figure 2: Low Henry Hub Gas Price Forecast**
**($/MBTU)[39]**




The Company's Low Henry Hub forecast in the 2025 IRP is within the range of the other publicly available forecasts and very close to the average of the other forecasts Staff derived. Compared to the low gas forecast in the 2022 IRP ("LG0"), the 2025 IRP low natural gas price forecast is higher in the short-term then closely follows the 2022 IRP Update forecast in the long term.

[39] Publicly Available sources include Duke Indiana 2024 IRP, Dominion Energy South Carolina 2025 IRP Update, Santee Cooper 2024 IRP Update, PacifiCorp 2025 IRP, Tennessee Valley Authority Draft 2025 IRP, and Indiana Michigan Power Company 2024 IRP.

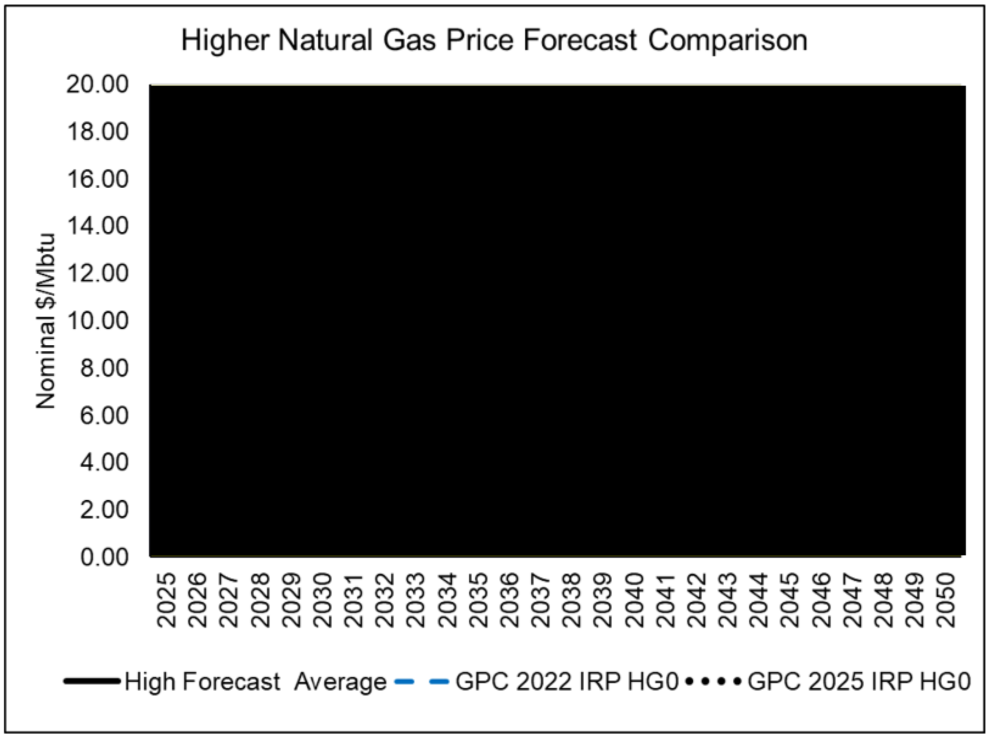
**Figure 3: Moderate Henry Hub Gas Price Forecast Comparison ($/MBTU)[40]**




Staff included a NYMEX futures projection from April 9, 2025 in the Moderate Henry Hub comparison. The Company's Moderate 2025 IRP forecast was above the NYMEX futures projection; however, the Company's 2025 IRP Moderate forecast was lower than but still within the range of the other publicly available forecasts compared. The Company's 2023 and 2025 IRP Moderate gas price forecasts were close to each other.

[40] Publicly Available sources include Duke Indiana 2024 IRP, Entergy NOLA 2024 IRP, Dominion Energy South Carolina 2025 IRP Update, Santee Cooper 2024 IRP Update, PacifiCorp 2025 IRP, Tennessee Valley Authority Draft 2025 IRP, EIA AEO 2025 Reference Case, AVISTA 2025 IRP, NYMEX Futures, and Indiana Michigan Power Company 2024 IRP.

**Figure 4: High Henry Hub Gas Price Forecast Comparison ($/MBTU)[41]**




The Company's High Henry Hub forecast is mostly within the range of the other publicly available forecasts and very close to the average of the other forecasts Staff derived. Compared to the 2022 IRP High natural gas price forecast (HG0), the 2025 IRP High natural gas price forecast is lower in the short-term, but then closely follows the 2022 IRP forecast over the long-term.

[41] Publicly Available sources include Duke Indiana 2024 IRP, Dominion Energy South Carolina 2025 IRP Update, Santee Cooper 2024 IRP Update, PacifiCorp 2025 IRP, Entergy NOLA 2024 IRP, Tennessee Valley Authority Draft 2025 IRP, and Indiana Michigan Power Company 2024 IRP.

Based on the Low, Moderate and High gas price forecasts Staff developed, Staff concluded our forecasts were similar to the Company's forecasts and adopted the Company's forecasts for our modeling analyses.

**Q. HAS STAFF EVALUATED THE COMPANY'S $CO_2$ EMISSION PRICE FORECAST?**

A. Yes. The Company modeled three $CO_2$ futures, Lower, Moderate, and Higher. Each of these futures reflected an approximate price and start date for $CO_2$ emissions costs. Lower assumed a $0/ton, Moderate $20/ton, and Higher $50/ton starting price. The Company's Moderate and Higher carbon pricing scenarios begin in 2030, and the Company's 111 + Higher scenario begins in 2035. The $20/Ton Moderate scenario escalates at 5% per year, while the $50 Higher and 111 + Higher scenarios escalate at 7% per year on a constant nominal basis. Staff reviewed the moderate and higher forecasts against peers, and though the Company's forecasts are on the higher side, they are within the peer range.

The Company put forward the MG0 and MG0-111 scenarios as primary cases in various analysis, and as such, Staff's review and analysis considered these two cases the primary views for expansion planning as they most closely reflect a future with carbon pressure (111 GHG rule) and one without, which provides important context for decision making.[42]

Planning Scenarios

[42] Main Document, p. 61 Projected Seasonal Capacity Needs, Tables 8.1A and 8.1B.

**Q. WHAT SCENARIOS DID THE COMPANY EVALUATE IN ITS RESOURCE MIX STUDY?**

A. The Company provided a summary of the scenarios it evaluated on page 4 of the Resource Mix Report. Ultimately, the Company presented nine scenarios and the Company's Planning Scenarios table is reproduced below as Table 12. The table indicates that depending on the scenario, the Company relied on different assumptions for four key areas of uncertainty, including $CO_2$ (111 GHG pressure), technology costs (Tech), fuel, and load growth. The Company described these cases as both plausible and meaningfully different views of the future.[43]

**Table 12: GPC Planning Scenarios**

| Scenario | GHG pressure view | Tech view | Load view | Fuel view | Label |
|---|---|---|---|---|---|
| 1 | 111 | Tech Portfolio | Standard | Moderate | 111-MG0 |
| 2 | 111 | Tech Portfolio | Standard + HG0 delta | Higher | 111-HG0 |
| 3 | 111 + Higher | IRA 2035 | Standard | Moderate | 111-MG50 |

| Scenario | GHG pressure view | Tech view | Load view | Fuel view | Label |
|---|---|---|---|---|---|
| 4 | Lower | Tech Portfolio | Standard | Lower | LG0 |
| 5 | Lower | Tech Portfolio | Standard | Moderate | MG0 |
| 6 | Lower | Tech Portfolio | Standard + HG0 delta | Higher | HG0 |
| 7 | Moderate | IRA 2045 | Standard | Moderate | MG20 |
| 8 | Higher | IRA 2035 | Standard | Moderate | MG50 |
| 9 | Emissions Limit | IRA 2045 | Standard | Moderate | EL |

The scenarios were divided into two sets. The first set of three cases complies with the 111 GHG rules that have been finalized, as described on page 5 of the Company's 2025 IRP Resource Mix Study, and the second set of six cases assume the EPA 111 rules will

[43] 2025 IRP Resource Mix Study Report, p. 4.

not remain in effect. In addition to complying with the EPA 111 rules, the Company considered the inclusion of $CO_2$ taxes ($CO_2$ pressure) in different cases. The Lower case assumed zero $CO_2$ taxes would be in effect but assumed all new NGCC units operational in 2040 and later would require use of $CO_2$ carbon sequestration.[44] The Moderate and Higher views both included the NGCC carbon sequestration requirement, but beginning in 2037. The Emissions Limit case imposed the requirement that $CO_2$ emissions would be reduced 95% by 2050 compared to 2007 emissions levels.

The Tech view considered three cost uncertainty views reflecting the timing when phase-out of the Inflation Reduction Act ("IRA") production tax credits ("PTCs") and investment tax credits ("ITCs") will occur. The Tech Portfolio view assumed PTCs and ITCs would exist all through the study horizon, the IRA 2035 Tech view assumed phase out would begin in 2035, and the IRA 2045 Tech view assumed phase out would begin in 2045.[45] Staff's review and analysis considered the MG0 and 111-MG0 cases as described in Table 12 above.

<u>Load Forecast</u>

**Q. WHAT LOAD FORECASTS WERE EVALUATED IN THE RESOURCE MIX STUDY?**

[44] Staff believes the carbon sequestration modeling requirement is unrealistic given CCS commercial performance to date and included it as an option and not a mandatory requirement in its Aurora modeling runs. The Company noted at p. 8 of the 2025 IRP Resource Mix Study Report that the availability date and costs of NGCC with sequestration are highly uncertain.

[45] 2025 Resource Mix Study Report, pp. 7-9.

A. The Company only produced two load views, Standard and Standard + HG0 Delta, which were nearly identical.[46] On behalf of Staff, the Load Forecast Panel developed alternative load forecasts, which mainly differ in assumptions regarding the economic development load. The table below shows two alternative load forecast sensitivity cases the Load Forecast Panel developed compared to the Company's Base Case load forecast. The case referred to as Staff 1 reflects an adjustment Staff made to rely on uniform load realization model ("LRM") assumptions for all large loads. Staff 2 is a sensitivity load forecast that only includes large loads that have made commitments to the Company by signing either Request for Service ("RFS") or Contract for Service ("CFS") agreements.[47]

[46] GPC's response to STF-JKA-2-37 explains that the Standard + HG0 Delta case includes a higher forecast of load, plus an assumption of higher natural gas prices. The Company explained that while the higher forecast of load increases load forecast, the higher natural gas prices dampens load growth, and therefore, the two load forecasts are not dramatically different.

[47] This case aligns with the "Committed Large Load, Announced Load" LRM results presented in Staff's Load Forecast Panel's testimony.

**Table 13: Staff Load Forecast Alternative Scenarios**
**Winter Peak MW**

| | Base | Staff 1 | Staff 2 | Staff 1 | Staff 2 |
|---|---|---|---|---|---|
| | GPC B2025 Standard | LRM Uniform Assumptions | Base+ Committed Large Loads | Delta | Delta |
| 2028 | 20,320 | 19,157 | 18,332 | (1,163) | (1,988) |
| 2029 | 22,168 | 20,574 | 19,483 | (1,594) | (2,685) |
| 2030 | 23,612 | 21,743 | 20,489 | (1,869) | (3,123) |
| 2031 | 24,469 | 22,459 | 21,018 | (2,010) | (3,451) |
| 2032 | 24,900 | 22,826 | 21,338 | (2,074) | (3,562) |
| 2033 | 25,213 | 23,093 | 21,579 | (2,120) | (3,634) |
| 2034 | 25,451 | 23,297 | 21,771 | (2,154) | (3,680) |
| 2035 | 25,653 | 23,474 | 21,925 | (2,179) | (3,728) |
| 2036 | 25,768 | 23,585 | 22,025 | (2,183) | (3,743) |
| 2037 | 25,987 | 23,799 | 22,228 | (2,188) | (3,759) |
| 2038 | 26,216 | 24,024 | 22,441 | (2,192) | (3,775) |
| 2039 | 26,605 | 24,406 | 22,813 | (2,199) | (3,792) |
| 2040 | 26,917 | 24,718 | 23,117 | (2,199) | (3,800) |
| 2041 | 27,295 | 25,134 | 23,552 | (2,161) | (3,743) |
| 2042 | 27,687 | 25,522 | 23,931 | (2,165) | (3,756) |
| 2043 | 28,118 | 25,948 | 24,347 | (2,170) | (3,771) |
| 2044 | 28,544 | 26,368 | 24,755 | (2,176) | (3,789) |

The Load Forecast Panel produced the Staff 1 and Staff 2 load forecasts. Of those, the Load Forecast Panel has relied on Staff 1, the LRM Uniform Assumptions case, as its preferred forecast in this IRP. Staff considers its load forecast alternative scenarios to be a conservative assumption, as other utilities, like Dominion Energy South Carolina, require customers to have contracts for service before including them in their load forecast.[48]

[48] In Dominion Energy's South Carolina ("DESC") 2024 IRP Report, South Carolina Public Service Commission Docket No. 2024-9-E, DESC stated at p. 115, "The difference in modeling results between the Updated 2023 Reference Build Plan and the 2024 Reference Plan is due primarily to the recent addition to the forecast of 256 MW of contractually committed load from creditworthy parties." https://dms.psc.sc.gov/Attachments/Matter/3a27d786-346f-45cd-8a5a-05471ee1cedb

<u>Generic Resources</u>

**Q. WHAT RESOURCES DID THE COMPANY IDENTIFY FOR USE IN ITS EXPANSION PLAN OPTIMIZATION ANALYSES?**

A. The table below contains the list of resources that were evaluated in the predominant number of expansion plan studies the Company performed. The data was taken mainly from tables in the Company's Resource Mix Study, unless otherwise noted.[49]

**Table 14: Summary of Company Modeled Generic Resources**

| Resource Name | Short Name | Overnight Cost (2030 $/kW)[50] | Capacity Equivalence (%) | Build Time (Yr) [51] | Asset Life (Yr) | MG0 Date Available |
|---|---|---|---|---|---|---|
| Combined Cycle | CC | [redacted] | 100% | [redacted] | [redacted] | 2029 |
| Combined Cycle with CCS (Local) | CC w Local CCS | [redacted] | 100% | [redacted] | [redacted] | 2037 |
| Combined Cycle with CCS (Distant) | CC w Distant CCS | [redacted] | 100% | [redacted] | [redacted] | 2037 |
| Combustion Turbine with Future Emission Controls | CT w SCR | [redacted] | 100% | [redacted] | [redacted] | 2029 |
| Solar Photovoltaic - Single Axis Tracker | Solar | [redacted][52] | 0% | [redacted] | [redacted] | 2028 |
| Onshore Wind Power | Wind | [redacted] | 35% | [redacted] | [redacted] | 2033 |
| Lithium-ion Battery Energy Storage System (BESS) - 4 Hour | BESS | [redacted] | Declining Tranches [53] | [redacted] | [redacted] | 2028 |
| Medium Duration Energy Storage System | MDESS | [redacted] | 100% | [redacted] | [redacted] | 2033 |
| Nuclear (AP-1000) | Nuclear | [redacted] | 100% | [redacted] | [redacted] | 2037 |

[49] 2025 IRP, Resource Mix Study Report, Table 4: Candidate Technology Assumptions, pg. 21 and Table 5: B2025 Technology Cost and Performance Summary, pg. 25.
[50] Staff escalated to 2030$ using a [redacted] escalation rate. Includes EPC, Owners Cost, Land, excludes AFUDC.
[51] From SAM files, spending curves provided in confidential workpapers.
[52] Approximately a levelized $[redacted]/MWh after accounting for PTC, Maintenance Capital, FOM.
[53] In the Resource Mix Study tranches were modeled as follows: 0-3,000 MW: 95%; 3001-6000 MW : 75%; 6001-9000 MW : 50%; 9001+ MW : 25%. Staff notes that the Company's BESS modeling has improved to consider impacts to accredited capacity as new BESS resources are added and retired over the study horizon, See Company response to STF-JKA-3-25 describing the modeling change.

**Q. DID STAFF EVALUATE THE REASONABLENESS OF THE GENERIC RESOURCE COSTS AND OPERATIONAL CHARACTERISTICS?**

A. Yes. Staff compared the costs to other sources, including the National Renewable Energy Laboratory ("NREL"), Lazard, and a selection of utilities to assess the reasonableness of assumptions. Staff provides this assessment as Generic Resource Comparison Exhibit NHSW-6. Also, as part of the evaluation, Staff considered confidential information based on bid information from the Company's 2029-2031 All-Source RFP, which is currently underway, and recent Certificate of Public Convenience and Necessity ("CPCN") proceedings.[54]

**Q. DID STAFF IDENTIFY ANY CONCERNS ABOUT THE COMPANY'S CAPITAL COST ASSUMPTIONS USED IN THE RESOURCE MIX STUDY?**

A. Yes. Staff determined that some of the generic resources included in the expansion plan optimization analysis reflected lower capital cost assumptions than should reasonably be expected today. Specifically, Staff is concerned that there has been significant market pressure on the cost of constructing new CT and CC resources given the demand many utilities are experiencing to satisfy large economic development load requirements. Furthermore, supply chain issues and other drivers have led to significantly inflated capital costs over the past one to two years, particularly with CTs and CCs, but also with other technologies, as well. The issue associated with increased CT and CC capital costs is well

[54] Docket No. 55378 Georgia Power Company's 2023 Integrated Resource Plan Update for Robins, Moody, Hammond, and McGrau Ford PI & PII BESS and Yates 8-10 Units

documented in industry articles.[55] A recent New York Times article made the following points regarding gas turbine capital costs:

- About this time last year, interest in natural gas to power data centers picked up, catching much of the energy industry off guard.
- By some estimates, it now costs two or three times as much to build a gas-fired power plant as it did a few years ago.
- These days, the backlog is so severe as to be reminiscent of the snarled supply chains of the pandemic, which constrained production of cars, medical devices and much more.
- Between those delays and the time it takes to build a power plant, a company starting from scratch today would probably not have a new gas plant running before 2030. Other critical electrical equipment like transformers is also harder to get.[56]

The Company's Resource Mix Study reflected a generic CC price of approximately [redacted]/kW ($2030).[57] Staff has reviewed the underlying cost components and determined the Company's B2025 generic pricing is much lower than current market expectations. As described above, Staff produced a comparison of generic cost pricing from various industry sources in Exhibit NHSW-6. The Combined Cycle comparison includes data points demonstrating increasing trends in the Company's own forecasts between the 2022 IRP, 2023 IRP Update, and 2025 IRP. The comparison also includes data points for the Duke

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[55] Examples include, heatmap.news/ideas/natural-gas-turbine-crisis, www.powermag.com/gas-powers-boom-sparks-a-turbine-supply-crunch, www.bloomberg.com/news/articles/2025-03-11/ge-vernova-ceo-sees-order-backlog-stretching-into-2028.

[56] "Why a Plane-Size Machine Could Foil a Race to Build Gas Power Plants," New York Times, https://www.nytimes.com/2025/04/08/business/energy-environment/gas-turbines-power-plants.html, Rebecca Elliot, April 8, 2025.

[57] Total Overnight Cost includes EPC Cost, Land and External Infrastructure Cost, and Owner's Cost.

Indiana Cayuga proposed NGCC,[58] the KU/LGE Brown and Mill Creek proposed NGCCs,[59] which indicate the Company's generic pricing may be understated by [redacted]%.[60]

Similarly for the Company's generic CTs, Staff is concerned that the Company's CT capital cost assumption was not modeled high enough, accounting for the increased demand for CTs that has recently occurred, which in turn has been caused by the significant load growth in the US. Staff estimates the generic CT prices modeled by the Company may have been understated by approximately [redacted]%.[61]

**Q. WHAT OTHER CONCERNS DOES STAFF HAVE RELATED TO THE COMPANY'S ASSUMPTIONS REGARDING CC AND CT CAPITAL COSTS?**

A. Though this is not an issue for this IRP, Staff is concerned that given the rapid increase in costs to construct CTs and CCs, bids received in the 2029-2031 All Source RFP will need to be scrutinized very carefully to ensure they are in line with current market expectations. For example, if the Company were to underbid capital costs for Company owned resources, and its resources were to win the RFP, it would likely need to seek an increase in the certified cost from the Commission at a later time. This is an issue Staff will have to monitor closely in the RFP proceeding.

58 https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/0940df1c-4aea-ef11-be20-001dd80ad83d/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=NEW%20CAUSE_Duke%20Energy%20Indiana_Petition_021325.pdf

59 https://psc.ky.gov/pscecf/2025-00045/rick.lovekamp%40lge-ku.com/02282025010202/16-Tummonds_Direct_Testimony_2025-00045.pdf

60 [redacted]

61 [redacted]

In addition, Staff is concerned about the Company's cost of debt assumption and the Company's Weighted Average Cost of Capital ("WACC") calculation that the Company has relied on in various Company analyses. Though for purposes of IRPs, new units are generally evaluated using a marginal cost of capital (rather than embedded), it should be noted that the cost of capital and the capital structure in the 2025 IRP do not reflect the latest Commission approved rates from the 2022 Rate Case.[62] Additionally, the debt rates assumed in this IRP ([redacted]) appear high compared to embedded rates. Financing assumptions used in future IRP and RFP evaluations should be as accurate as possible.

**Q. DOES STAFF HAVE ANY CONCERNS ABOUT THE COMPANY'S ASSUMPTIONS THAT WERE USED TO MODEL BESS AND RENEWABLE RESOURCES IN THE RESOURCE MIX STUDY?**

A. Yes. Staff is concerned about the Company's assumption regarding the rate at which BESS project capital costs decline over time, as can be seen in Figure 12 of the Company's Resource Mix Study Report. Staff acknowledges that, like solar and wind resources, BESS capital costs may drop over time; however, the prices the Company modeled in the Resource Mix Study are lower than the BESS prices the Company assumed in the 2023 IRP Update and bid prices in the Company's BESS RFP procurements. Staff determined that the Company's assumed generic BESS prices are too low by approximately [redacted]%. Similarly, based on Staff's review of recent solar pricing and industry trends, Staff

[62] The Commission's approved capital structure includes a 56% equity/ 44% debt, and a 10.5% ROE. The Company's various IRP models deviated slightly. For example, the Hydro Modernization and Generic Resource Cost derivations included an [redacted]% ROE assumption with a 55% equity /45% debt capital structure.

estimates approximately a [redacted]% cost increase would be appropriate for renewable energy resources (solar and wind resources).[63] As discussed further below, Staff increased capital cost for CCs and CCs w CCS by [redacted]%, CTs by [redacted]%, BESS and MDESS by [redacted]%, and Solar and Wind by [redacted]% in its Aurora Optimization analyses. [64]

Other Modeling Considerations

**Q. DID STAFF REVIEW THE RENEWABLE INTEGRATION STUDY AND ELCC STUDIES?**

A. Yes. The Company's Renewable Integration Study was performed to derive the cost of maintaining additional operating reserves required to reliably operate the system with increasing penetration of solar resources. Staff's EERE Renewables panel concluded it was appropriate to capture some level of integration cost in modeling solar resources in our Aurora expansion plan modeling process. The Company assumed $[redacted]/MWh ($2023 escalating), and Staff adopted that for use in its Aurora modeling. Staff's EERE Renewables panel also reviewed the Company's Effective Load Carrying Capability ("ELCC") assessment for solar and determined an initial tranche of solar should have a capacity accreditation value in the Resource Mix Study. Staff's study reflects the results of the Company's ELCC analysis.[65]

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[63] Staff also reviewed highly confidential bids submitted to the 2029-2031 AS RFP in its evaluation.

[64] These adjustments were made by applying the percentage increase each year across the study horizon for simplicity and is considered a conservative adjustment by Staff.

[65] STF-JKA-1-10. STF-JKA-1-10 Attachment A includes results for BESS and STF-JKA-1-10 Attachment D includes results for Solar, which includes 5% for winter, and 25% for summer for the first 3,000 MW of incremental additions.

**Q. DID THE COMPANY CONSTRAIN RESOURCE ADDITIONS IN ITS MODELING RUNS?**

A. Yes. The Company included nine selectable generic resource types for expansion planning, identified in Table 4 of the Resource Mix Study, titled "Candidate Technology Assumptions." Table 4 shows the constraints the Company accounted for in its Aurora modeling, including dates when resources would first become available for selection, the last year resources could be selected, CT capacity factor constraints, Fixed Transportation ("FT") fuel constraints, and restrictions on the availability of subsidies available from the Inflation Reduction Act ("IRA").

**Q. PLEASE DISCUSS THE CT CAPACITY FACTOR CONSTRAINTS.**

A. The Company modeled a 20% capacity factor constraint, though it does not appear the Company has a well-defined reason for the constraint, as the Company explained it "is intended to broadly represent limitations on combustion turbine operation that could be attributed to permit limitations and performance standards under the Clean Air Act."[66] The Company explained this constraint was not binding in some of the cases, including the MG0, LG0, HG0, and MG20 cases.[67] This implies it was binding in various 111 GHG Rule cases, in which CC capacity factors were also limited by virtue of the 111 GHG Rule requirements. Staff is concerned that the specific application of CT capacity factor model

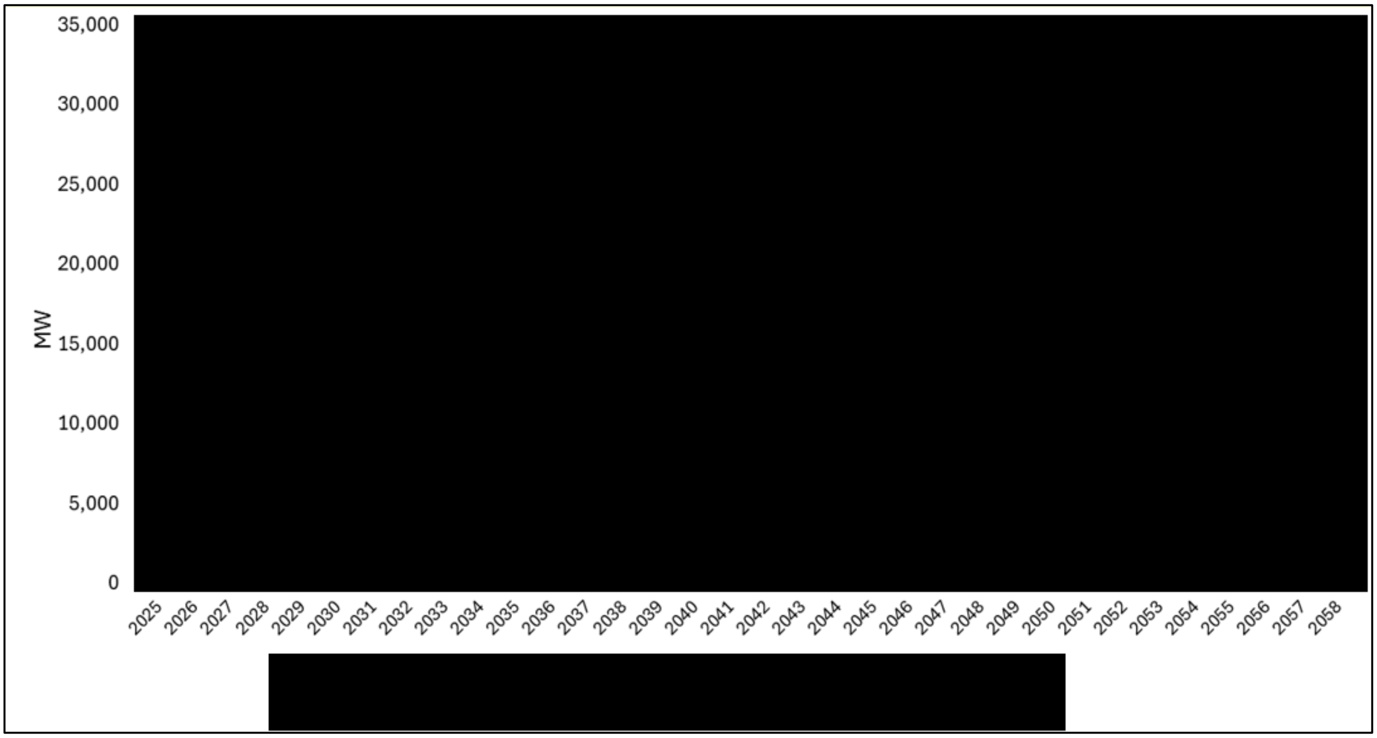
[66] STF-JKA-3-16-d.
[67] *Id.* at g.

limitations may impact the derivation of the expansion plan and should be more well defined in the future.

**Q. DID YOU REVIEW THE COMPANY'S PROPOSED CC BUILD LIMIT AND FT ASSUMPTIONS?**

A. Yes. The Company limited the number of CCs that could be built over a given period of time based on the assumption that there is a limited amount of pipeline capacity and FT availability. The Company developed its estimated amount of FT availability for new CCs considering that some amount would be needed for existing units and PPAs, though it did consider that an amount would be recovered when units retire or PPAs expire. The Company assumed some additional FT availability would become available during the planning horizon based on [redacted] and it earmarked [redacted]. The Company provided the following figure in the Resource Mix Study Report to explain the amount of CC capacity that could be built over time as FT availability increases. The figure contains results for 2025 EPA 111 cases, 2025 non-EPA 111 cases, the 2050 Emissions Limit case ("EL"), and the FT availability assumption that the Company relied on for the 2023 IRP Update for all scenarios.

**Figure 5: NGCC Build Limits in the Resource Mix Study (MW)[68]**




The table indicates that compared to the 2023 IRP, the Company assumed in this IRP that more FT capacity would be available and therefore, more CC resources could be built over time. All the cases in the 2025 IRP included the same assumption regarding pipeline availability through 2038, though different assumptions were made for the different cases after that.

In response to discovery, the Company indicated it is in the process of acquiring [redacted] MMBTU/day of additional FT capacity by [redacted] through new pipeline expansion projects and [redacted] MMBTU/day by [redacted] as a result of unit retirements and expiration

[68] STF-JKA-1-11-b

of PPAs.[69] Based on the Company's assumption that a CC unit requires approximately [redacted] MMBTU/day, this equates to approximately [redacted] MW CC units ([redacted] MW) based on the pipeline expansion projects being available in 2028.[70] In total, this amounts to [redacted] MW available for selection in [redacted] due to rounding assumptions for modeling purposes. The Company also modeled [redacted] MWs of CC capacity based on retiring units and expiring PPAs in [redacted][71] [redacted]

At this point, Staff is unaware whether the Company has a line of sight to FT availability that may be needed to comply with the 111 GHG rule by 2030, which would require at least another [redacted] MMBTU/day[72] for 40% co-firing at Bowen and Scherer, or to serve load after 2035.

Staff finds the Company's analysis does not appropriately address the substantial uncertainty regarding the achievability of the Company proposed FT limit assumptions and

[69] STF-JKA-1-11-a and STF-JKA-5-19
[70] STF-JKA-1-11 Attachment A [redacted] STF-JKA-1-13 Attachment A [redacted] It is unclear if the expected additional pipeline capacity will be in-service on the current projected schedule.
[71] Georgia Power response to STF-JKA-1-13.
[72] STF-PIA-4-9 Attachment TRADE SECRET

the trajectory of possible load growth futures and the impacts these assumptions have on the resource needs contemplated in this IRP. Staff found the Company's discovery responses incomplete on this matter and recommends that the Company provide clarity on the FT assumptions used to justify the inclusion of the [redacted] MW of CCs in the Company's MG0 case in rebuttal testimony.

**Q. DID THE COMPANY MODEL CCS AS A RESOURCE OPTION?**

A. Yes. The Company included two CC with CCS selectable resource options in its resource optimization modeling, with separate resources modeled for local $CO_2$ disposal versus disposal at a longer distance. Depending on the GHG Pressure View that the Company modeled (See Figure 5, above) the Company assumed that any new NGCC unit would need to be a CCS unit (by 2037 for the Lower view, and 2040 for the Moderate and Higher views).[73] Staff is concerned about this assumption for two reasons; 1) it appears to be an arbitrary constraint, if the Company wanted to offer a CCS option for $CO_2$ reduction optionality it could have included an additional CC option, not the only CC option available; 2) the commercial viability of CCS for electric generators is unproven and high risk.[74] The Company acknowledges this concern as well stating, "While this trajectory and ultimate costs remain highly uncertain, the inclusion of NGCC with CCS allows the Company to evaluate scenarios for this potential future resource option."[75] Staff allowed for both options to be selectable in its modeling.

[73] 2025 IRP Resource Mix Study, p. 6.
[74] Mississippi Power Company Plant Kemper.
[75] 2025 IRP Resource Mix Study p. 8.

Scenarios, Resource Need, and Expansion Plan Development

**Q. PLEASE DISCUSS THE CAPACITY NEED SITUATION FOR SOUTHERN COMPANY AND GEORGIA POWER.**

A. As discussed above in the Reserve Margin section, after establishing the System TRM, Southern Company derived the corresponding TRM values that applied to Georgia Power, which were determined by accounting for the diversity of Georgia Power's peak demand compared to the System's peak demand. The following table compares Georgia Power and Staff's TRM assumptions for both the System and Georgia Power based on the winter.

**Table 15: Target Reserve Margin - Winter**

| | **Derived by Company (%)** | **Derived by Staff (%)** |
|---|---|---|
| System TRM | 26.0 | 24.5 |
| Georgia Power TRM | 25.13 | 23.7 |

While the winter season is of primary importance in this IRP, the seasonal dynamics between the system and individual operating companies do change over time with increased demands that are weather insensitive. The Company explained:

> While the Georgia Power capacity need in the summer exceeds that of the preceding winter until the summer of 2031, that is not the case with the System needs. This indicates Georgia Power may not need to add resources to fully address its own incremental summer capacity needs but rather could leverage other resources on the System.[76]

**Q. WHEN DOES STAFF EXPECT THE COMPANY'S NEXT NEED FOR CAPACITY WOULD BE?**

[76] 2025 IRP Main document, p. 60.

A. Using the Company's load forecast and TRM assumptions, the next need for capacity is Winter 2027/2028; however, under Staff's load forecast and TRM assumptions, the next need for capacity is pushed out one year until Winter 2028/2029. The starting position assumptions for both the Company and Staff appear in Exhibit NHSW-5 Case 1 and Case 4 (Load and Resource Balance Tables), respectively, as well as in Tables 4a and 4b above. The Company's intention is to satisfy its next resource need by adding the incremental resources it has identified (capacity upgrades and WTR options) and by selecting bids from the 2029-2031 All Source RFP. In addition to the load forecast and TRM assumptions differences, another difference between the Company and Staff was that the Company only accounted for one of two 500 MW BESS RFPs in its Starting Position load and resource balance table (STF-JKA-1-3, Attachment A). In other words, the Company only accounted for the 2022 500 MW ESS RFP, but not the 2023 500 MW BESS RFP. Staff accounted for both in its Starting Position load and resource balance table.

**Q. WHAT ADDITIONAL GENERATION RESOURCES IS THE COMPANY PROCURING TO MEET LOAD IN 2029 – 2031 THAT WILL ADD TO THE COMPANY'S TOTAL CAPACITY RESOURCES?**

A. The following table shows a set of RFPs not currently completed that are expected to provide additional capacity.[77]

[77] Staff did however, account for ~98 MW related to Company's proposed demand response program

**Table 16: Pending RFPs [78]**

| RFP | Status | Years Sought | Certification Expected | Target MW |
|---|---|---|---|---|
| **All-Source Capacity RFP** | Active | 2029-2031 | November 2025 [79] | 8,500 MW[80] |
| **CARES 2023 US RFP** | Active | 2026-2028 | December 2024 [81] | 2,875 MW [82] |
| **CARES 2025 US RFP** | Active | IE retained, expect to issue June 2025 [83] | | |
| **2023 DG RFP** | Completed | 2024 | July 2024 [84] | 42 MW |
| **2024 DG RFP** | Active | 2025 | Sept. 2025 | 251[85] |
| **Future DG RFP [86]** | | 2027-2029 | | 100 MW |
| **Winter 2027/2028 BESS RFP** | Active (2023 IRP) | 2025-2027 | Aug. 2025 | 500 MW [87] |
| **ESS RFP** | Active (2022 IRP) | IE retained, expect to issue Q4 2025 [88] | September 2027[89] | 500 MW |

[78] See Company response to STF-JKA 1-24 and also Main Document at p. 11 describing 2023 IRP Update status (#3) and pg. 13 describing 2022 RFP and incremental capacity addition approvals (#11, 12, 13, 14, 15, 16, 17, and 30)

[79] Main Document, p. 13. The Company expects to submit a certification application for the winning submissions in July 2025, with an order expected from the Commission by November 2025.

[80] https://psc.ga.gov/search/facts-document/?documentId=219760 Estimated Capacity Need from 2023 IRP for winter 2030/2031 (as noted on page 16).

[81] Main Document, p. 13, "12. Issued the CARES 2023 US RFP for Renewable Generation on December 22, 2023. Determination of the Short List is slated to be announced in Q1 2025. The Company expects to issue the CARES 2025 US RFP for Renewable Generation by June 2025."

[82] STF-JKA-1-24 Attachment B.pdf, p. 16.

[83] *Id.*

[84] Main Document, p. 13, "13. Issued the 2023 RFP for Solar Photovoltaic Distributed Generation ("2023 DG RFP") on August 28, 2023. Executed 12 PPAs for a total of approximately 42 MW, each of which were deemed certified by the Commission throughout the fall of 2024."

[85] Main Document, p. 80, "In the 2022 IRP, the Commission approved two distributed generation renewable RFPs, the 2023 DG RFP and the 2024 DG RFP, which sought to procure energy from 293 MW of solar resources (which included 93 MW rolled over from the 2020 DG RFP)"

[86] Main Document p. 60, "Issue the 2026 and 2027 Distributed Generation RFPs, each for 50 MW, for a total of 100 MW of distributed generation resources to reach commercial operation in 2027, 2028 and 2029."

[87] Main Document, p. 11, "3. Issued the Winter 2027/2028 BESS RFP to the market on August 9, 2024, for the additional BESS resources that are needed during the winter of 2027/2028 based on the 2025 IRP Load Forecast. Bids were due on September 16, 2024, and the competitive tier was identified on October 10, 2024. Capacity needs are currently expected to exceed the 500 MW projected during the 2023 IRP Update. The Company is evaluating the results of the Winter 2027/2028 BESS RFP as well as investigating additional resource options to meet customer needs should the RFP be insufficient to fill all capacity needs."

[88] Main Document, p. 13, "16. The Company expects to issue the 500 MW ESS RFP in Q4 2025 with expected certification from the Commission in Q3 2027."

[89] *Id.*

Company Resource Mix Study Results

**Q. HAVE YOU REVIEWED THE COMPANY'S RESOURCE MIX STUDY RESULTS?**

A. Yes. After evaluating the Company's input assumptions, Staff reviewed the outputs of the Company's Resource Mix Study. The following table presents the Company's results on both a Georgia Power basis and a Southern Company basis, for both the MG0 and the 111 MG0 cases. The results generally indicate that the Company's expansion plan through 2034 is likely to include a balance of new CT, CC, BESS, Solar and some wind resources. Under a 111 GHG Rule future, considerably more solar capacity is anticipated to meet energy requirements.

**Table 17: Company Resource Mix Study Result (Nameplate) [90]**

| Cumulative Adds Through 2034 | | | | | | |
|---|---|---|---|---|---|---|
| CASE | | CT w/ SCR | CC | Solar | Wind | Battery 4-hr [91] |
| GPC | MG0 | 3,540 | 3,930 | 1,980 | 330 | 3,360 |
| SYSTEM | MG0 | 3,900 | 5,400 | 3,000 | 600 | 3,900 |
| GPC | 111 MG0 | 3,330 | 4,140 | 6,320 | 120 | 4,140 |
| SYSTEM | 111 MG0 | 3,600 | 5,700 | 8,400 | 600 | 4,800 |

While these results provide guidance about the type of resources that may be added to the Company's system over time, RFPs will play a critical role in identifying the specific resources that should be added. Staff's EERE Renewables panel discusses the Company's request for additional solar procurements

[90] Capacity Expansion Plans - 2025 IRP.xlsx
[91] Tranche 1 and Tranche 2.

**Wholesale to Retail Acquisition**

**Q. PLEASE DISCUSS THE OFFER THE COMPANY HAS MADE TO SELL WHOLESALE CAPACITY TO RETAIL CUSTOMERS ("WTR") IN THIS IRP?**

A. In this IRP, the Company has offered four blocks of Scherer 3 capacity totaling 187 MW to retail customers available between 2026 and 2031. The following table provides details of the Scherer 3 Wholesale Block ("WB") offer.

**Table 18: Wholesale to Retail Offer Summary – Scherer Unit 3**

| Wholesale Capacity Block | | Capacity (MW) | Date Placed in Retail Service |
|---|---|---|---|
| B1 | EnergyUnited Coal Block | 52.0 | 1/1/2026 |
| B2 | Flint EMC Steam Block | 55.3 | 1/1/2030 |
| B3 | Retail – FPL | 54.8 | 1/1/2031 |
| B4 | Retail – DEF | 24.5 | 6/1/2031 |

**Q. PLEASE DESCRIBE THE COMPANY'S METHODOLOGY FOR DERIVING THE OFFER PRICE.**

A. The Company's methodology was intended to determine the value of the WBs if the capacity were sold in the current wholesale market. The Company's goal was to charge customers the book value of the WB capacity based on normal regulatory ratemaking requirements but then apply a market differential adjustment ("MDA") to either reduce or increase the book value so that ratepayers would ultimately pay the Company the same amount the Company would have received had it sold the capacity in the market.

The Company derived separate MDAs depending on whether the 111 GHG Rule future was assumed to be in effect or not, as the expected revenue requirements, operating life, and market value of Scherer 3 would depend on the outcome of the 111 GHG Rule.

Under the 111 GHG Rule future, the Company assumed Scherer 3 would co-fire on natural gas, and Scherer 3 was assumed to operate through 2038. Under the no 111 GHG Rule future, the Company assumed Scherer 3 would operate through 2035.

**Q. DID THE COMPANY PROVIDE AN ANALYSIS IN SUPPORT OF THE 2025 IRP WTR OFFER?**

A. Yes. The Company determined that for most of the blocks in both the 111 GHG Rule future and the no 111 GHG Rule future, the market value of the Scherer resources was [redacted] the revenue requirement to equal the market value in all, but one block as seen in the table below. In the following table the 111 GHG Rule future is referred to as the MG0-111 case, and the no 111 GHG Rule future is referred to as the MG0 case.

**Table 19: Wholesale to Retail MDA Proposals $/kW-mo**

| Wholesale Capacity Block | | MG0 (thru 2035) | MG0-111 (cofire, thru 2038) |
|---|---|---|---|
| B1 | EnergyUnited Coal Block | [redacted] | |
| B2 | Flint EMC Steam Block | | |
| B3 | Retail – FPL | | |
| B4 | Retail – DEF | | |

**Q. HAS THE COMPANY'S METHODOLOGY FOR DERIVING THE MDA CHANGED SINCE THE 2022 IRP?**

A. Yes. In the 2022 IRP, the MDA was set based on the results of the 2022-2028 Capacity RFP and the Company's methodology did not reflect the actual year of capacity need. In this IRP, the Company updated its methodology to calculate the capacity value of the market proxy based on the ECC of a CT beginning in the Company's first year of capacity need. Though the Company's new methodology aligned with Staff's 2022 IRP recommendation related to the market proxy, Staff is concerned in this IRP about potential changes to the offered price based on uncertain regulatory conditions and retirement assumptions. The use of a market proxy price based on a CT resource was inconsistent with the Company's valuation of Scherer 3 in the URS, which assumed a CC resource as the market replacement for Scherer 3. Furthermore, the Company's 2035 retirement assumption used in the no 111 GHG Rule case was different than the retirement assumption the Company used in the URS, which was 2043.

**Q. WHAT IS STAFF'S OPINION OF THE COMPANY'S APPROACH TO EVALUATING THE SCHERER 3 WHOLESALE TO RETAIL BLOCKS?**

A. The Company's market proxy analysis was not the best approach that could have been used to determine the market value of the WBs. The best test would have been to bid the WBs in to the 2029-2031 All Source RFP to determine the market value compared to the other RFP resources. Additionally, acquiring the WBs through the RFP would have reduced uncertainty related to future cost and term conditions.

**Q. WHAT WAS STAFF'S APPROACH TO EVALUATING SCHERER 3 WHOLESALE TO RETAIL BLOCKS?**

A. Staff did compare the WBs to market alternatives (2029-2031 All Source RFP bids); however, the results indicated the WBs were economically marginal and not compelling enough to make a recommendation to the Commission in favor of taking the blocks.

**Q. WHAT IS STAFF'S RECOMMENDATION?**

A. If the Commission determines to take more capacity than Staff is recommending in this IRP, then Blocks 1 - 3 should be the first additional resources procured. Should the Commission seek even more capacity, then Staff recommends that Block 4 only be considered if the Company were to agree to [redacted] (MDA adjustment).

**Unit Retirement Study**

**Q. PLEASE DESCRIBE GEORGIA POWER'S UNIT RETIREMENT STUDY ("URS').**

A. Georgia Power's URS evaluated the economic feasibility of various environmental compliance options for its coal and select natural gas steam units. The Company evaluated Scherer, Gaston, and Bowen which are summarized in the Table below. Staff includes a 75-year life column to demonstrate an outer range of possible retirement dates (absent environmental compliance requirements) the Company could consider rather than the fixed retirement dates used by the Company in its study.[92] An optimal retirement date analysis would be most appropriate.

[92] 2025 IRP Unit Retirement Study p. 9 "The Company did not complete a study evaluating the extension of Gaston 1-4 beyond 2035 given the age of the units." Gaston would be approximately 75 years old by 2035.

**Table 20 – Candidate Retirement Units Summary [93]**

| Unit | Fuel | GPC % | Summer MW | Winter MW | In-Service Date | Current Age | Retirement Year at 75 |
|---|---|---|---|---|---|---|---|
| **Bowen 1** | Coal | 100% | 714 | 740 | 1971 | 54 | 2046 |
| **Bowen 2** | Coal | 100% | 705 | 760 | 1972 | 53 | 2047 |
| **Bowen 3** | Coal | 100% | 910 | 950 | 1974 | 51 | 2049 |
| **Bowen 4** | Coal | 100% | 910 | 910 | 1975 | 50 | 2050 |
| **Scherer 1** | Coal | 8.4% | 75.2 | 75.2 | 1982 | 43 | 2057 |
| **Scherer 2** | Coal | 8.4% | 75.2 | 72.2 | 1984 | 41 | 2059 |
| **Scherer 3** | Coal | 75% | 537.4 | 537.4 | 1987 | 38 | 2062 |
| **Gaston 1** | Coal/Gas | 50% | 127 | 127 | 1960 | 65 | 2035 |
| **Gaston 2** | Coal/Gas | 50% | 128 | 128 | 1960 | 65 | 2035 |
| **Gaston 3** | Coal/Gas | 50% | 102 | 102 | 1961 | 64 | 2036 |
| **Gaston 4** | Coal/Gas | 50% | 102.6 | 102.6 | 1962 | 63 | 2037 |
| **Gaston A** | Oil | 50% | 7.7 | 9.7 | 1970 | 55 | 2045 |

The Company performed stand-alone, unit-specific analysis that compared the total cost of each compliance pathway and continued operation of the candidate unit to the immediate replacement cost of a generic natural gas CC plant. The study's objective was to determine whether continued operation under various environmental regulations would be economically justified compared to retiring the units and replacing them with CCs. Staff is concerned about the assumed replacement with a CC resource, and recommends the Company perform retirement studies using an optimization modeling analysis, which would consider all possible types of resources.

The Company used a separate spreadsheet analysis to evaluate each of the retirement candidate units. Georgia Power assumed immediate replacement of the existing

[93] Georgia Power Company's 2025 Integrated Resource Plan Table C.1 – Company-Owned Resources – Conventional. The MW values represent Georgia Power share of the capacity (MW) of each unit.

units would occur in 2029, following retirement, given several of the resources under consideration were previously assumed to retire by December 31, 2028. The study period extended through 2073 to align with the proposed NGCC's useful life. Since the study period extended through 2073, well beyond the expected life of the candidate units, the Company utilized a term equalization adjustment to align the study cases. The term equalization adjustment replaced the retiring resource with a modeled new CC plant for the period after its retirement. This ensured the comparison incorporated the costs and benefits associated with delayed investment in that replacement CC and its related transmission infrastructure

**Q. PLEASE EXPLAIN THE COMPANY'S EVALUATION METHODOLOGY.**

A. The Company evaluated the economics of extending the existing units' operation in two phases. First, the Company focused on the economics of extending the units by comparing the costs and benefits of the EPA Effluent Limitations Guidelines ("ELG")-Compliant pathways (Phase 1). Second, the Company incorporated the implications of the ELG rule while capturing the 111 GHG rules (Phase 2). The Company included the option of a NGCC replacement unit coming online by 1/1/2029 in all of these individual analysis cases.

The Supplemental ELG (Phase 1) analysis included three compliance pathways for Plant Bowen and Scherer rule compliance. These compliance pathways are summarized as follows:

- **2028 Retirement:** Immediate retirement of the units by 12/31/2028.
- **Continued Operation:** Installation of environmental controls.

  - Plant Bowen - Zero Liquid Discharge ("ZLD") system by 12/31/2029 and Combustion Residual Leachate ("CRL") for a capital cost of $[redacted] million.[94]
  - Plant Scherer – Satisfied by compliance with the 2020 ELG rule. Supplemental ELG capital costs of approximately $[redacted] million for the GPC ownership share.[95]
  - Additionally, the extended operation case for both Scherer and Bowen includes costs associated with Combustion Residual Leachate ("CRL") by 12/31/2029 as well as Coal Combustion Residual ("CCR") Landfill and Waste Water Management Capital and O&M expenses. The Company modeled the retirement date in this case as 12/31/2043, though it is not specifically tied to ELG compliance regulation sunset date.
- **Imminent Retirement 2034:** Permanent Cessation of Coal Combusiton ("PCCC") and commitment to retire the units by 12/31/2034 without further ELG upgrades.

The Phase 1/Phase 2 approach was designed to determine first if ELG was economic, and if so, whether it was also economic to take action to be able to continue to operate to meet the 111 Rule requirements. Phase 2 included four options for both ELG and 111 GHG Rule that had to be evaluated. The Company describes the 4 pathways on page 6 of the unit retirement study, which are summarized as follows:

- **2028 Retirement:** Immediate retirement of the units by 12/31/2028 to avoid ELG costs, as well as coal unit operating costs.
- **Imminent Retirement 2031**: Retire by 1/1/2032 to avoid ELG costs (ZLD Bowen) and having to take actions to comply with EPA 111 regulations.

[94] 2025 IRP Unit Retirement Study Section 5 Pg 9 TRADE SECRET Errata 4-23-25.docx, $[redacted] million is associated with ZLD capital, and $[redacted] million with CRL capital in 2030.
[95] *Id.*

- **Co-Fire Gas 40% by 2030:** Incur ELG costs (ZLD Bowen) by 12/31/2029, co-fire 40% on natural gas by 1/1/2030, and retire by 12/31/2039. This pathway will require additional amounts of FT to get enough natural gas to the unit to co-fire.
- **100% gas Conversion by 2030:** Full conversion to natural gas by 1/1/2030 and retire by 12/31/2043. This pathway avoids the ELG costs (ZLD Bowen), but requires a greater amount of FT as discussed further below;
- **CCS by 2032**: Incur ELG costs (ZLD Bowen) to continue coal operation but install CCS to operate 90% $CO_2$ capture by 1/1/2032.

The following table provides a summary comparison of the compliance options considered for the Scherer and Bowen candidate retirement studies, with differences related to supplemental ELG compliance provided in the footnotes.

**Table 21: Candidate Retirement Cases (Bowen and Scherer)**

| Stage | Case Description | ELG | ZLD/ CRL | Gas Conv. | CCS | Retire Date |
|---|---|---|---|---|---|---|
| **ELG (Phase 1)** | 2028 Retirement, build CC | N | N | N | N | Dec 31, 2028 |
| | Extended Operation[96] | Y | Y | N | N | ~Dec 31, 2043 |
| | Imminent Retirement 2034 | Y | N | N | N | Dec 31, 2034 [97] |
| | | | | | | |
| **ELG + 111 GHG Rule (Phase 2)** | 2028 Retirement, build CC | N | N | N | N | Dec 31, 2028 |
| | Imminent Retirement 2031 | Y | N | N | N | Jan 1, 2032 |
| | Co-Fire Gas 40% by 2030 | Y | Y | Y | N | Jan 1, 2039 |
| | 100% gas Conversion by 2030 | N | N | Y | N | ~Dec 31, 2043 |
| | CCS by 2032 | Y | Y | N | Y | ~Dec 31, 2043 |

[96] Current Scherer ELG compliance plans expected to meet both 2020 and 2024 Supplemental ELG rule standards with only small incremental costs related to wastewater captured in the two forward cases.

[97] "2025 IRP Unit Retirement Study PUBLIC DISCLOSURE.docx," p. 3 describes, "the Permanent Cessation of Coal Combustion ("PCCC") pathway, which involves committing to the discontinuation of coal operation by December 31, 2034. This option allows facilities to avoid the incremental costs associated with installing new additional ELG controls. Instead, facilities must submit a Notice of Planned Participation ("NOPP") to the Georgia Environmental Protection Division ("EPD") by December 31, 2025, and comply with the 2020 Rule's generally applicable limits."

In each phase of the analysis the Company performed a series of economic evaluations to compare the continued unit operation options versus a replacement NGCC. The Company modeled production cost savings for seven planning scenarios: MG0, MG20, MG50, LG0, HG0, 111-MG0, and 111-MG50 as part of its analysis. These scenarios considered multiple views of future pressure on the Company's $CO_2$, future cost and performance of generating technologies, future electricity consumption, and the future price of fuels.

For Plant Gaston the Company's environmental compliance strategy reflected full gas operations. The Company evaluated retiring the Gaston units in 2034, and an alternative case that captured incremental investments related to full gas operations, which would comply with both ELG and 111 GHG Rule futures. The incremental costs captured included Maintenance Capital, 316B Intake Screens, Gas Yard Upgrades, Ash Controls Transfer, Fixed O&M, Gas Compression O&M, and Summer Release FT.

**Q. WHAT COSTS AND BENEFITS WERE INCLUDED IN THE COMPANY'S URS STUDY?**

A. The Company's analysis captured energy benefits, and 45Q tax credits under the IRA with the energy benefits quantified through the production cost savings in the Aurora model.[98] The analysis included fuel costs, fixed and variable O&M expenses, transmission expenses, and incremental capital expenditures and was structured to derive the on-going costs and

[98] To calculate the energy benefits in Aurora the Company established a base case for the applicable scenario and pathway, which replaced the candidate retirement unit with peaking units (CTs) and then reintroduced the candidate retirement units in a change case. In order to maintain reliability, the Company replaced the coal capacity with generic CT capacity in the modeling to attempt to isolate the energy value of the resources.

benefits of continued operation of the candidate retirement units. The customer benefits presented by the Company were derived through a comparison of the NPV of the continued operation of the candidate units to the NPV of retiring the candidate units and acquiring replacement NGCC capacity. The net benefit calculation scaled the existing unit capacity to the replacement unit capacity to compare the NPV of the cases on an even capacity basis.

**Q. WHAT WERE THE COMPANY'S URS RESULTS FOR BOWEN?**

A. The Company's analysis determined that it was economic under both the MG0 and MG0-111 scenarios to continue operation of the Bowen units as the estimated PVRR for that case was less than the PVRR for the replacement NGCC case.[99] Staff presents the Company's PVRR results in the following table, for the MG0 and MG0-111 scenarios only.

**Table 22: Georgia Power's Bowen Compliance Assessment (PVRR $M)[100]**

| Stage | Case Description | Retire Date | RR[101] | Trans. | Term Equi | Benefits[102] | Net Costs (Benefits) |
|---|---|---|---|---|---|---|---|
| **ELG (Phase 1) MG0** | Retire, build CC | Dec 2028 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Extended Operation | Dec 2043 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Imminent Retirement[103] | Dec 2034 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | | | | | | |
| **ELG + 111 GHG Rule (Phase 2) MG0-111** | Retire, build CC | Dec 2028 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Imminent Retirement | Jan 2032 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Co-Fire Gas 40% | Jan 2039 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | 100% gas Conversion | Dec 2043 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | CCS | Dec 2043 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

99 Tables 5 through 9 in Section 6 of the 2025 IRP Unit Retirement Study Report (Technical Appendix Volume 2) contains the Company's results with additional detail of the study results provided in Appendix A and B of the same document.
100 2025IRP_AV_ BowenU1-4 TRADE SECRET.xlsx
101 Includes FT assumptions provided by Georgia Power
102 Includes 45Q tax credits for CCS
103 Permanent Cessation to Coal Combustion ("PCCC")

The Company's results show that if the 111 GHG Rule legislation is stayed, then the only evaluation that matters is Supplemental ELG Compliance (Phase 1, MG0), and the Extended Operation option is the most economic choice, as the Net Costs are the lowest for that option. However, if the Company has to comply with the 111 Rule (Phase 2 – current legislation), then for the MG0-111 case, the Imminent Retirement plan (by January 2032) is the least cost option.

Other factors should also be considered. Due to the Company's capacity needs and the uncertainty of the 111 GHG Rule, the Company's proposal to move forward with the co-fire pathway is reasonable and offers a risk mitigation position. This position is helpful in two ways, first if EPA 111 remains the law of the land it reduces the Company's need to procure additional FT capacity which is already constrained, and it maintains more fuel diversity in the generation portfolio. Second, if the EPA 111 Rule is stayed, then the Company has the option to revert to the least cost option of ZLD coal operation until 2043. It is important for the Company to consider the timing of the required investments for the co-firing option. The Company should delay the procurement of FT, construction of the needed lateral and boiler upgrades until the uncertainty of the current regulatory environment is decided. The Company acknowledges this flexibility as well.

***Q. Sure. But in addition to the FT side, would you also agree that there are going to be costs that are going to stem from negotiations that Georgia Power needs to make with pipeline companies in getting the FT -getting the firm transportation of the natural gas to the sites?***

*A. (Witness Grubb) Yeah. We haven't -- we're not actively going and getting the FT right now, because we don't want to commit to it until the*

> *latest moment we need to based on the status of 111. But it would be discussions with the pipelines, correct.*[104]

Staff highlights the difference in efficiency between co-firing Bowen compared to operating a new CC resource. The co-fire option assumes consumption of [redacted] MMBTU per day of natural gas for 40% co-fire operation, which equates to 1,248 MW of the Bowen Units capacity (40% * 3,120 MW).[105] This same amount of FT could alternatively be used at a new [redacted] MW CC resource, which would provide more capacity and energy for the same amount of MMBTUs/day.[106] This inefficiency issue is highlighted even more by the full conversion to 100% natural gas operation at Bowen, which would require [redacted] MMBTU per day at an estimated cost of approximately $[redacted] Million per year. Alternatively, the Company could construct an additional [redacted] MW of new CC capacity that would use about [redacted] MMBTUs/day, which would provide more capacity for the system.[107] The purpose of pointing this out is to indicate the challenges the Company will have to deal with in meeting the EPA regulations, which may lead to significant inefficiencies in operations. These considerations were factored into the economic analysis, which shows that the decision between retirement, co-firing, and full gas conversion is a close call. Another factor that complicates matters is that load growth is driving the Company to make commitments for FT capacity, yet ultimately the load growth may not materialize as quickly as the Company expects.

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[104] Transcript, Vol. 1, Tuesday March 25, 2025, p. 0382.

[105] STF-PIA-4-9 Attachment TRADE SECRET

[106] STF-JKA-1-11 Attachment A, assumes [redacted] Equivalent CC capacity derived by [redacted]

[107] *Id.*

**Q. PLEASE DISCUSS THE COMPANY'S RESULTS FOR SCHERER 3.**

A. The following table demonstrates the Company's analysis following the same methodology as described for Bowen.

**Table 23: Georgia Power's Scherer 3 Compliance Assessment (PVRR $M)[108]**

| Stage | Case Description | Retire Date | RR | Trans. | Term Equi | Benefits[109] | Net Costs (Benefits) |
|---|---|---|---|---|---|---|---|
| ELG (Phase 1) MG0 | Retire, build CC | Dec 2028 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Extended Operation | Dec 2043 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Imminent Retirement | Dec 2034 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | | | | | | |
| ELG + 111 GHG Rule (Phase 2) MG0-111 | Retire, build CC | Dec 2028 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Imminent Retirement | Jan 2032 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Co-Fire Gas 40% | Jan 2039 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | 100% gas Conversion | Dec 2043 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | CCS | Dec 2043 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

Like Bowen, the Phase 1 results indicate that if the 111 GHG Rule is stayed (under an MG0 future), the Continued Operation is the most economic choice for Scherer 3. This option would allow the Company to continue to operate an existing resource and to maintain fuel diversity for its generation fleet. The Company's modeling shows that CCS operation would be the most economic option for the Company under the current 111 GHG rule (Phase 2). However, as discussed above, Staff is concerned with the commercial viability of CCS. It is also important to point out most of the benefits of the CCS option come from the Company utilizing the 45Q tax credits. After eliminating the CCS option, the Co-Fire Gas 40% case is the least cost for the Company under the MG0-111 scenario. Similar to

[108] 2025IRP_AV_SchererU1-3_TRADE SECRET.xlsm
[109] Includes 45Q tax credits for CCS

concerns raised regarding Bowen, Staff questions the Company's ability to procure the additional [redacted] MMBTU/day of FT needed for the co-firing option, given its concurrent proposals to build more CC units. This option would equate to approximately 232 MW in 2031 (580*0.40) and cost approximately [redacted] million annually.[110] This amount of FT would allow an additional [redacted] MW of new CC capacity to be built on the system.[111]

**Q. PLEASE DISCUSS THE COMPANY'S RESULTS FOR GASTON**

A. For Plant Gaston, the Company evaluated the continued operation through 2035 to the construction of a new NGCC.[112] The Company's analysis showed the continued operation though 2035 was the least cost. Staff agrees with the Company's results, and in modeling Staff performed, continued operation of Gaston was assumed in every case.

**Q. DO YOU HAVE ANY CONCERNS REGARDING THE COMPANY'S MODELING APPROACH FOR THE UNIT RETIREMENT STUDY?**

A. Yes. Staff's primary concern is the Company's decision not to use an economic optimization modeling process to evaluate replacement resources in a comprehensive manner. Staff also had concerns about the Company's use of a transmission cost penalty, and the term equalization assumptions used in their economic evaluations. Staff is also concerned that the Company's compliance costs assumed in the study were preliminary and possibly understated. Specifically, Staff is concerned that the ZLD costs and CCS cost estimates provided may be unreliable.

[110] STF-PIA-4-9 Attachment TRADE SECRET
[111] STF-JKA-1-11 Attachment A
[112] "2025 IRP Unit Retirement Study PUBLIC DISCLOSURE.docx" p. 9 "The Company did not complete a study evaluating the extension of Gaston 1-4 beyond 2035 given the age of the units."

The Company assumed new CC resources would have a transmission cost, and that continued operation of existing facilities would defer that cost until retirement occurs. This may be one possible outcome, though another is that replacement generation could be sited at the retiring facility and therefore transmission investment would be minimized. If transmission costs were excluded from the Company's Unit Retirement Study for Bowen's 3,360 MW, the benefits of retirement would decrease approximately $[redacted] million for a 9-year deferral (2035 to 2043) and $[redacted] billion for a 13-year deferral (2029 to 2043) on a NPV basis. The following table shows the results of the Company's economic analysis. In a non-EPA 111 compliance case, the retirement in 2043 is not tied to any specific outcome or threshold requirement, and continued operation could be contemplated to an earlier or later date. [113] The analysis shows that with transmission costs removed, Imminent Retirement would be the most economic option in both the MG0 Phase 1 (ELG) Study and MG0-111 GHG Rule Phase 2 analyses for Bowen as shown below.

**Table 24: Staff Adjusted Bowen Results without Transmission (PVRR $M)**

| Stage | Case Description | Retire Date | RR | Trans. | Term Equi | Benefits[114] | Net Costs (Benefits) |
|---|---|---|---|---|---|---|---|
| ELG (Phase 1) MG0 | Retire, build CC | Dec 2028 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | Extended Operation | Dec 2043 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | Imminent Retirement | Dec 2034 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | | | | | | | |
| ELG + 111 GHG Rule (Phase 2) MG0-111 | Retire, build CC | Dec 2028 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | Imminent Retirement | Jan 2032 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | Co-Fire Gas 40% | Jan 2039 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | 100% gas Conversion | Dec 2043 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | CCS | Dec 2043 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |

[113] STF-JKA-2-19
[114] Includes 45Q tax credits for CCS

The following table shows the same analysis for Scherer 3 with transmission costs removed. Based on the Supplemental ELG (Phase 1) analysis results, continued operation would be the most economic option, and based on the ELG + 111 GHG Rule (Phase 2) analysis, aside from the CCS results, co-firing would be the most economic option, though cofiring would also be a close call with retirement by January 2032.

**Table 25: Staff Adjusted Scherer 3 Results without Transmission (PVRR $M)** [115]

| Stage | Case Description | Retire Date | RR | Trans. | Term Equi | Benefits[116] | Net Costs (Benefits) |
|---|---|---|---|---|---|---|---|
| **ELG (Phase 1) MG0** | Retire, build CC | Dec 2028 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | Extended Operation | Dec 2043 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | Imminent Retirement | Dec 2034 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | | | | | | | |
| **ELG + 111 GHG Rule (Phase 2) MG0-111** | Retire, build CC | Dec 2028 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | Imminent Retirement | Jan 2032 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | Co-Fire Gas 40% | Jan 2039 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | 100% gas Conversion | Dec 2043 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |
| | CCS | Dec 2043 | [redacted] | 0 | [redacted] | [redacted] | [redacted] |

**Q. PLEASE EXPLAIN THE COMPANY'S USE OF A TERM EQUILIZATION ADJUSTMENT.**

A. The Company uses a "Term Equalization" adjustment to address the problem of evaluating resources having different lives. The candidate resources are assumed to be replaced at the end of their useful lives with CC resources that have longer operating lives. It was not unreasonable for the Company to address the issue of unequal lives; however, Staff believes that a better approach would be to perform the analysis relying on an optimization

115 2025IRP_AV_SchererU1-3_TRADE SECRET.xlsm
116 Includes 45Q tax credits for CCS

analysis, in which resources are optimally selected when resources retire. Staff used this approach for its analysis using the Company's Aurora model.

**Q. WHAT IS STAFF'S CONCLUSION REGARDING THE UNIT RETIREMENT STUDY.**

A. Staff found that the Company's coal retirement analysis and proposed 111 GHG Rule compliance study results were significantly influenced by the impacts of transmission costs and term equalization adjustment costs. However, Staff acknowledges that uncertainties regarding the amount of load the Company will have to serve, the availability of natural gas FT capacity, and the need to ensure an adequate and reliable supply of resources led Staff to agree that the co-firing pathway is a reasonable approach if the Company will have to comply with the EPA 111 Rule requirements. Nevertheless, while Staff agrees the Company should plan for the co-firing pathway, Staff recommends the Company defer as long as possible incurring significant expenses related to the Plant Bowen co-firing strategy until there is greater clarity on the 111 GHG Rule. See below for additional discussion of Staff's coal retirement analysis using its modeling approach.

**<u>Nuclear and McIntosh Upgrade Evaluations</u>**

**Q. PLEASE DESCRIBE GEORGIA POWER'S EVALUATION OF UPGRADES AT VOGTLE 1&2 AND HATCH 1&2 NUCLEAR UNITS, AND THE MCINTOSH 10 AND 11 CC AND THE MCINTOSH 1A-8A CT UNITS.**

A. The Company performed evaluations of upgrade opportunities at these units by comparing incremental costs to incremental benefits of the upgrades. The benefits consisted of a capacity benefit (based on the economic carrying charge of a CT) and an energy benefit that was derived using Aurora. The Company's analysis compared the capital and operating costs that would be incurred by upgrading the units, to the benefits that would be derived by increasing the amount of capacity produced by the units. The Company conducted evaluations between 2026 and the end of the useful lives of the associated units.

The Company's results are summarized below for the MG0 and MG0-111 cases. The additional amount of capacity that will result from the upgrades is listed in the first row of the table.

**Confidential Table 26: Company Upgrade Analysis Summary (MG0, MG0-111)**

| | **Hatch 1-2** | **Vogtle 1-2** | **McIntosh CC [117]** | **McIntosh CT** |
|---|---|---|---|---|
| Incremental MW (Winter) | 58 | 54 | 194 | 72 |
| Incremental MW (Online Year) | 2030-2031 | 2029-2032 | 2029 | 2027-3034 |
| | | | | |
| **$Millions** | | | | |
| Incr Capital (Cost)/Benefit PVRR (MG0) | [redacted] | [redacted] | [redacted] | [redacted] [118] |
| Incr Energy/Capacity Benefit PVRR (MG0) | [redacted] | [redacted] | [redacted] | [redacted] |
| **Net Benefit (Cost) NPV (MG0)** | [redacted] | [redacted] | [redacted] | [redacted] |
| Breakeven Year | [redacted] | [redacted] | [redacted] | [redacted] |
| | | | | |
| Incr Capital (Cost)/Benefit PVRR (MG0-111) | [redacted] | [redacted] | [redacted] | [redacted] |
| Incr Energy/Capacity Benefit PVRR (MG0-111) | [redacted] | [redacted] | [redacted] | [redacted] |
| **Net Benefit (Cost) NPV (MG0-111)** | [redacted] | [redacted] | [redacted] | [redacted] |
| Breakeven Year | [redacted] | [redacted] | [redacted] | [redacted] |

[117] The Companies filed supplemental information May 1, 2025 describing impacts to the economic analysis relating to the transmission stability analysis performed for the Plant McIntosh upgrades. The results shown in Table 26 above reflect the filed information.

[118] The McIntosh CT Incremental (Cost)/Benefit appears as a positive value because the Company expects there to be a reduction in future recurring capital costs associated with the upgraded CTs, and on a NPV basis, the reduction in future recurring capacity costs is expected to be greater than increase in capital costs to upgrade the CTs.

The Breakeven Year shown in the table indicates how long it will take for each project to become cost effective. The CT projects are almost immediately cost-effective. Additional discussion of the Breakeven Year is included below.

While the McIntosh CC project will be relatively expensive to upgrade, the benefits are that the upgrade will yield an increase in capacity, can be implemented relatively quickly, and will offer additional dispatch energy benefits based on efficient CC resources. Overall, the project results in a net benefit to customers starting in 2046 through the remaining life of the plant (2050). Staff is concerned that the upgrades may not be achieved in full and recommends the Company only be approved for costs associated with achieved MW on a pro-rata basis, as presented in this filing.

Even though the nuclear units were found to be economic, the projects are capital intensive, will require significant lead time to perform the upgrades, and will take a relatively long time to break even. Staff recommends the Commission approve the Company's request for incremental capacity upgrades at Plant Vogtle Units 1-2, which are more economic, but delay the upgrades at Plant Hatch Units 1-2 to be completed two years after Vogtle 1-2 are completed. This delay will allow the Company to incorporate its experience with Vogtle 1 – 2 upgrade in its execution of the Hatch 1 – 2 upgrade. Staff also recommends the Commission require the Company to limit cost recovery for these projects to the projected cost estimates on an approved $/kW basis, as presented in this filing.

**Q. EARLIER, YOU MENTIONED STAFF PERFORMED BREAKEVEN ANALYSES BASED ON THE COMPANY'S RESULTS. PLEASE DESCRIBE THOSE ANALYSES.**

A. Staff performed a cumulative PVRR analysis that determined the point in time when the cumulative PVRR benefits of the upgrade projects are expected to exceed the cumulative PVRR costs. The point at which the lines cross the horizontal axis denotes when the project is assumed to breakeven.

**Figure 6: Cumulative PVRR Net Benefits of the Nuclear and McIntosh CC Upgrades** [119]

[redacted]

The Vogtle and Hatch Units are expected to breakeven by [redacted], respectively.[120]

**Q. HAS THE COMPANY EXPRESSED AN OPINION OF WHETHER FACTORS SUCH AS THE BREAKEVEN POINT AND RATE IMPACTS SHOULD BE CONSIDERED IN DECIDING WHETHER TO MAKE THE CAPITAL INVESTMENT AT THIS TIME?**

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[119] "2025IRP_AV_McIntoshCC_TRADE-SECRET 5-1-25.xlsm" and "2025IRP_AV_Nuclear TRADE SECRET.xlsm"

[120] Staff's analysis uses the company's assumption for remaining operating life. Extended operations of nuclear units require Nuclear Regulatory Commission ("NRC") approval.

A. Yes, during the Company's hearing on its Direct Testimony, the question of rate impacts was raised, and the Company noted that project economics should be measured on a Net Present Value basis, rather than a rate impact basis:

> So this is not a rate case proceeding, and we're looking at 30-year decisions. And so the process has always been the IRP, long-term, net present value economic evaluations. Choosing the most economic resources helps serve those customers' needs as affordably as you can, and then that flows into the rate case.[121]

Staff does not disagree that generally construction projects are evaluated over the entire life of operation, however, that does not mean that other factors such as breakeven considerations, rate impacts, and other risks should not be considered at this time. Furthermore, the Company is seeking approval to perform the upgrades in this case, not the upcoming rate case, therefore, factors beyond lifecycle economics should be examined in this IRP.

**Q. WHAT ARE STAFF'S CONCLUSIONS REGARDING THE VOGTLE, HATCH, MCINTOSH CT AND THE MCINTOSH CC UPGRADES?**

A. The McIntosh CT upgrades require little consideration as the project's future recurring capital cost savings are expected to outweigh the upfront capital investment, and that alone justifies the project. The Plant Vogtle upgrades should be pursued as the project will result in a net benefit and will breakeven in a relatively short period of time compared to the length of time the plant is expected to operate ([redacted] versus [redacted] years, respectively). Staff is not opposed to the Hatch Upgrades; however, Staff recognizes that nuclear unit projects

[121] Georgia Power Hearing Transcript, March 25, 2025, testimony of Mr. Jeff Grubb, at p. 376. Also, see discussion at pp. 374 - 377.

carry additional risks compared to conventional generating unit projects. Staff would prefer to spread out the timeline for upgrading the Vogtle and Hatch projects, and Staff recommends the Commission approve the Company's request for incremental capacity upgrades at Plant Vogtle Units 1-2, but delay the upgrades at Plant Hatch Units 1-2 to be completed two years after the Vogtle 1-2 upgrades are completed. Staff also recommends the Commission require the Company to limit cost recovery for these projects to the projected cost estimates on an approved $/kW basis, as presented in this filing. Finally, Staff recommends approving the McIntosh CT and CC upgrades.

**Proposed Hydro Modernization**

**Q. WHAT IS THE COMPANY'S HYDRO MODERNIZATION REQUEST IN THE 2025 IRP?**

A. The Company is requesting Commission approval to modernize all of the remaining hydro units that were not approved for modernization in the 2019 IRP and 2022 IRP orders. The Company has provided a capital cost estimate of $1.5 billion to modernize these remaining hydro facilities.[122]

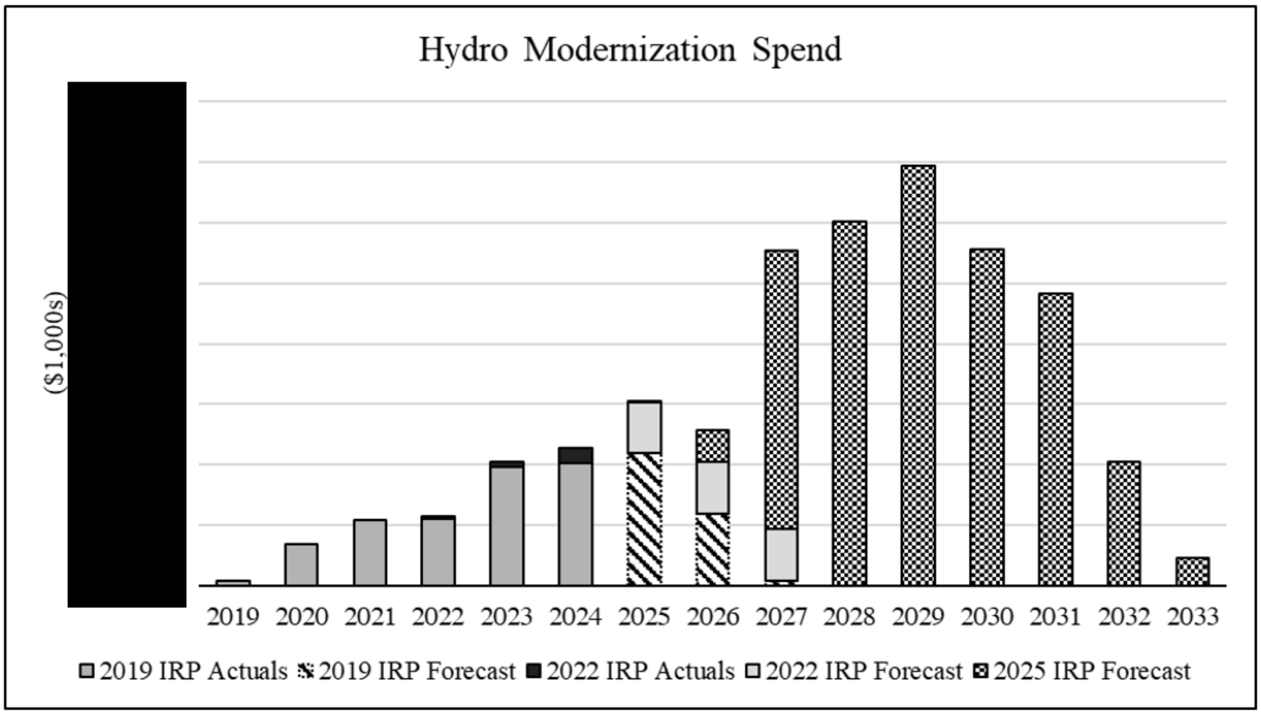
**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S HYDRO MODERNIZATION REQUEST?**

A. Staff recommends that the Company's request be denied in this proceeding. The Company has only completed 5 hydro units out of a total of 20 hydro units approved in the 2019 IRP

[122] In response to STF-JKA-2-30 the Company stated the Goat Rock modernization project would result in a 16 MW increase in capacity at the plant.

and 2022 IRP orders.[123] The Company has approximately $225 million remaining to complete the approved projects from the 2019 and 2022 IRPs.[124] As shown in Figure 7 below, the 2025 requests increase the average spend per year as well, and picks up significantly in 2027 and beyond.

**Figure 7: Approved and Proposed Hydro Modernization Spend[125]**




It would be premature to approve more hydro modernization capital expenditures in this proceeding when the Company has so much remaining work on previously approved projects to complete.

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[123] Georgia Power Company's Bi-Annual Hydro Modernization Update For the Period Ending December 31, 2024.The completed hydro units are Terrora 1 – 2 and Tugalo 1 – 3.
[124] Georgia Power Company's Bi-Annual Hydro Modernization Report, 2/17/2025, Docket No. 42310 & 44160
[125] *Id.*

**Q. DOES STAFF SUPPORT EXPANSION OF THE HYDRO MODERNIZATION PROGRAM?**

A. Yes. Staff recommends the Company be allowed to spend up to $100 million on preliminary investigation and engineering through 2027 on the most economic hydro units remaining to be modernized. With the results of the Company's preliminary investigation and engineering studies the Commission would be in a better position in the 2028 IRP to decide how to proceed with hydro modernization. By waiting until the 2028 IRP the Commission could evaluate the Company's execution on previously approved projects and take the Company's performance into account when considering approval of additional hydro modernization projects. Another benefit of waiting until the 2028 IRP is that more of the approved projects would be completed or further along and the Company could focus on fewer projects going forward.

## V. STAFF EVALUATION AND MIX STUDY

### Study Methodology

**Q. DID THE COMPANY PERFORM ALL ECONOMIC EVALUATIONS IN THIS IRP USING CONSISTENT DATA AND MODELS?**

A. No. In addition to the Resource Mix Study, the Company conducted other economic evaluations using different assumptions and modeling techniques. In this IRP, the Company performed six different studies as follows:

1. **Unit Retirement Study:** A spreadsheet analysis that used production cost results and compared continued operation of a unit targeted for retirement to operation of a replacement resource (CC). Energy and capacity benefits were derived and the model

considered transmission cost impacts and differences in the life of the retirement resource and the replacement resource (Term Equalization through 2073).

2. **Resource Mix Study:** Long-term capacity expansion plan optimization study using Aurora. Included optimal resource selection based on an unconstrained transmission system, included generic resource costs, and modeled the study horizon through 2059.

3. **Nuclear Upgrade Asset Valuation:** A Cost/Benefit study that compared the current nuclear configuration (business as usual) case to a case with an upgrade applied to a target nuclear unit. Additional capital and operating costs, capacity value (based on CT Economic Carrying Charge ("ECC")), and energy benefits (avoided energy costs) were considered.

4. **McIntosh Upgrade Asset Valuation:** A Cost/Benefit study that compared the current CT or CC configuration (business as usual) case to a case with an upgrade applied to the target McIntosh unit. Additional capital and operating costs, capacity value (based on CT ECC) and energy benefits (avoided costs) were considered.

5. **Wholesale to Retail Analysis:** A spreadsheet analysis that used production cost results and compared continued operation of a Scherer 3 expected revenue requirements to a market proxy price based on a CT resource. Energy and capacity benefits were considered, with computed value for Scherer 3 terminating in 2035 for the MG0 case, despite the URS considering continued economic operation through 2043.

6. **Hydro Modernization:** Compared the capital cost required to modernize a target hydro unit versus the capital cost required to remove the hydro unit and dam assuming dam removal would be obligatory upon retirement.

Although an economic analysis was performed in each of these studies, the studies were not integrated. For example, the Company could have modeled these resource decisions as options in the Resource Mix Study, and the Aurora optimization analysis could have been used to decide whether the resource decisions were economic. Had the Company done this, similar methodologies would have been used to evaluate all of the resources, and the Company would have been able to test the target resources against more realistic resource alternatives, such as resources likely to be selected in the ongoing 2029-2031 All-Source RFP. Furthermore, an integrated analysis would have allowed the Company to determine a project ranked order based on which incremental project would provide the most value to the system.

**Q. PLEASE PROVIDE AN OVERVIEW OF STAFF'S MODELING APPROACH.**

A. As in prior IRP cases, Staff conducted its own independent modeling analysis using the Aurora production cost and resource optimization modeling tool. Staff's modeling approach performed an integrated analysis that concurrently evaluated coal retirements, existing unit upgrade options, WTR capacity, expected capacity RFP resource options, and future generic resource options, including CTs, CCs, BESS and Solar. Because of the inherent benefits of the CT upgrade project, and because the Company's proposed hydro modernization project analysis does not identify incremental capacity ratings, Staff did not include those resource decisions in its Aurora modeling analysis. Similarly, because of the straightforward compliance strategy at Gaston and the age of the unit, Staff relied on the Company's modeling and locked in Gaston's operations through the end of 2034 as a base assumption.

**Q. WHAT CHANGES DID STAFF MAKE TO THE STRUCTURE OF THE COMPANY'S ANALYSIS?**

A. Staff conducted its evaluation and treated the Company's resource decisions as options that could be selected in Aurora. Staff conducted separate Aurora studies for both the MG0 and MG0-111 scenarios. Staff also conducted evaluations based on Staff's alternative load forecasts and using Staff's recommended TRM of 24.5%. As discussed above, while Staff's load forecasts are lower than the Company's, Staff still included a significant amount of high load factor economic development load in its forecasts. Staff used the winter demand reduction adjustments provided by the Load Forecast Panel and applied that reduction in every hour of the year to create the alternative load forecasts that were modeled in Aurora.

**Q. WHAT COAL UNIT ENVIRONMENTAL COMPLIANCE ASSUMPTIONS DID STAFF CONSIDER IN ITS STUDY?**

A. Staff modeled the same options considered by the Company in the URS.[126] However, Staff excluded the CCS option for Bowen and Scherer environmental compliance from consideration under the MG0-111 scenario. Staff is unconvinced that CCS technology will be commercially viable by 2032, and until there is more evidence that CCS will be a commercially viable option for aging coal units that could be installed in the early 2030 time period, Staff believes the CCS option for Bowen and Scherer resources should be eliminated, and just the co-firing and gas conversion options should be considered for compliance. Staff allowed coal units to retire in 2043 in the MG0 scenario, and in 2038 under the MG0-111 co-fire pathway. Ideally, the Company should conduct additional retirement analyses in future IRPs to determine more specific, optimal retirement dates for each coal unit.

**Q. WHAT ASSUMPTIONS DID STAFF REVISE IN ITS STUDY?**

A. The following table compares the input assumptions that Staff used in its analysis to the Company's assumptions. Other than the assumptions noted as different from the

[126] Staff modeled the candidate retirement units (e.g. Bowen 1-4) as a single resource (Bowen Plant), rather than individual units for convenience.

Company's, Staff relied on all of the Company's other B2025 modeling assumptions.[127] Staff used the same study horizon, 35 years (2025-2059), that the Company used in the Resource Mix Study. Staff also modeled proxy resources options as surrogates for the RFP bids the Company received in the 2029-2031 All Source RFP.[128]

[127] STF-JKA-3-20 addresses the Aurora versions used in the various analysis to accommodate optimized dispatch with co-firing logic. Staff relied on the Company's base evaluations and utilized Aurora version 14.2.1084 for the MG0 cases, and Aurora version 14.2.1104 for MG0-111 cases.

[128] Staff's analysis modified the terms of each RFP bid to coincide with the first winter available to reduce bias in Aurora on partial year operations.

1 **Table 27: Staff Study Assumption Summary**

| Data Assumption | Company Resource Mix Study | Staff |
|---|---|---|
| Load Forecast[129] | Standard | Staff 1: LRM Uniform (~1,869 MW reduction in 2030) Staff 2: RFS + CFS (~3,123 MW reduction in 2030) |
| System TRM | 26% Winter / 20% Summer | 24.5% Winter / 20% summer |
| Generics Pricing | B2025 | CC (and CCwCCS) [redacted] higher CT [redacted] higher BESS/MDESS [redacted] higher Solar/Wind [redacted] higher |
| Solar Capacity Value | 0% (Winter) | 5% Winter / 25% Summer (<3GW) 0% Winter / 0% Summer (>3GW) |
| NGCC w/ required CCS | MG0 – starting 2040 MG0-111 – starting 2032 | Removed constraints |
| FT Capacity and new Gas Resource Limits | [redacted][130] | Same. Defer availability of generic CT/CCs until 2032 to allow RFP resources to fill needs through 2031. |
| Capacity RFP Resources | N/A | Selectable Resource Options ([redacted]). Company Owned Proposals ("COP") [redacted] |
| Requests for Upgrades: | N/A | McIntosh CT (Fixed) McIntosh CC (Selectable) Nuclear (Selectable) |
| Bowen and Scherer Operations | MG0 (coal thru 2035) MG0-111 (co-fire thru 2038) | Options to reflect URS assumptions (with exception of CCS) |
| BESS RFP | 500 MW | 1,000 MW |
| Proposed DSM[131] | N/A | 97.65 MW Proposed Thermostat Demand Response Program |

[129] Includes peak diversity adjustment to reconcile individual company peaks to the system peak. See STF-JKA-1-1 part e.
[130] Resource Mix Study, page 28.
[131] Existing dispatchable DSOs were included as capacity resources in base assumption modeling.

**Q. SINCE THE RESOURCE MIX STUDY IDENTIFIES RESOURCES FOR THE ENTIRE SOUTHERN COMPANY SYSTEM, HOW WERE RESOURCES ALLOCATED TO GEORGIA POWER?**

A. In Georgia Power's Resource Mix Study, an optimal mix of generic resources were selected to satisfy the Southern Company load requirement. After the Southern Company expansion plan was determined, a spreadsheet analysis was performed to allocate specific resources to Georgia Power. The spreadsheet determined the amount of each resource type to allocate to each Operating Company to satisfy each company's peak demand and energy requirements. The Operating Companies with the greatest capacity need were assigned resources first.[132] Based on the Company's allocation process, Georgia Power was assigned a majority of the CT, CC, BESS Tranche 1, and MDESS capacity resources before 2036 (93%, 80%, 90%, and 95% respectively).

In Staff's analysis, because the Georgia Power 2029-2031 RFP resources were modeled, all of the selected RFP resources were assigned to Georgia Power. During that period generic resources were assigned to serve the incremental needs of the other Operating Companies. After 2031, generic resources were available to serve the needs of all Operating Companies on a system needs basis, consistent with the Company's Resource Mix Study approach.

**<u>Staff Results</u>**

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[132] "Capacity Expansion Plans - 2025 IRP.xlsx", Technical Appendix Vol2 Trade Secret, Resource Mix Study

**Q. WHAT WERE THE RESULTS OF STAFF'S NO GHG 111 RULE FUTURE EVALUATION (MG0)?**

A. The following table describes Staff's Selection Results under various load forecast and TRM scenarios identified through 2031 in the MG0 price-policy future and shows results for Georgia Power. The selections refer to the decisions that were made in Staff's Aurora optimization analysis, and the results indicate the amount of MWs that will be added based on the decisions made in Staff's analysis. The first column with results in the table indicates Staff conducted an Aurora analysis using the Company's load forecast and TRM, but used all of Staff's other assumptions to focus the comparison on differences caused by the load forecast and TRM assumptions.

**Table 28: Staff Case Selections through 2031 - Results (MG0)**
**Reliable Winter Capacity MW**

| Input Assumptions | Staff | Staff | Staff |
|---|---|---|---|
| **Load Forecast** | **GPC** | **Staff 1** | **Staff 2** |
| **TRM** | **26%** | **24.5%** | **24.5%** |
| **Selections** | | | |
| Hatch 1-2 Upgrade | 58 | 58 | 58 |
| Vogtle 1-2 Upgrade | 52 | 52 | 52 |
| McIntosh CC Upgrade | 194 | 194 | 194 |
| WTR B1 | - | - | - |
| WTR B2 | 55 | - | 55 |
| WTR B3 | 55 | - | 55 |
| WTR B4 | - | - | 25 |
| Bowen [133] | Thru 2043 | Thru 2043 | Thru 2043 |
| Scherer | Thru 2043 | Thru 2043 | Thru 2043 |
| 2029-2031 RFP Take | 7,591 | 4,382 | 2,862 |
| **Total MW** | **8,005** | **4,686** | **3,301** |

[133] "Thru 2043" indicates a decision was made to continue operating the unit through 2043 and assumes the Company will comply with supplemental ELG requirements.

Staff's MG0 analyses determined that the nuclear and CC Upgrades are economic and that the WTR resources are marginally economic. In addition, Staff's results indicated that it would be economic to perform the Bowen 1-2 and Scherer 3 environmental compliance upgrades related to supplemental ELG, and our modeling included operation of those units through 2043.[134]

Staff's analysis was not designed to determine the specific resources (bids) the Company should acquire in the 2029-2031 All-Source RFP; however, it was designed to demonstrate the comparative economics of the RFP resources and incremental resource additions, and to demonstrate that the amount of RFP resources taken should decrease as the load and TRM requirements are reduced. The Staff 1 Aurora analysis supports the results shown in Table 4 above, regarding the amount of RFP capacity that should be acquired through the 2029-2031 All-Source RFP. The differences in the amounts identified in the two analyses, relate to Southern Company and Georgia Power specific modeling methods and sizes of resource selections.[135]

Staff's recommendation of the amount of capacity that should be targeted in the 2029-2031 RFP is based on the load and resource balance results shown in Table 4b above. Staff used the results from that table to make the recommendation that the Company should

[134] Staff's analysis included the capital costs required at Bowen needed to meet the EPA Final 2024 Supplemental ELG Rule requirements, which require coal plants wanting to operate beyond 2034 to meet zero liquid discharge of scrubber wastewater by the end of 2029.

[135] Staff's computed RFP take in Aurora by 2031 as shown in Table 28 is 4,382MW, but Table 4b above shows 5,226 by 2031. This approximately 844MW differences is due to the discrete sizes of non-GPC modeled resources (300 MW) and RFP resources (bid size), Hatch and WTR selection differences, as well as differences in diversified load reserve margin requirements (23.7% GPC vs. 24.5% system) and portfolio optimization approach.

target 5,989 MW of resources in the 2029-2031 All-Source Capacity RFP. While the Company will not need all of that capacity until 2033, acquiring that amount of capacity early (2031) will offset the risk of higher load occurring, and will defer the need to conduct the next RFP until a later time.

**Q. WHAT WERE THE RESULTS OF STAFF'S 111 GHG RULE (MG0-111) EVALUATION?**

A. Staff's MG0-111 case was designed to evaluate if the same projects would still be selected under the MG0-111 view of the future. The same results are presented in the table below for MG0-111 analysis Staff performed.

**Table 29: Staff Case Selections through 2031 – Results (MG0-111)**
**GHG 111 Rule Future**
**Reliable Winter Capacity MW**

| **Input Assumptions** | **Staff** | **Staff** | **Staff** |
|---|---|---|---|
| **Load Forecast** | **GPC** | **Staff 1** | **Staff 2** |
| **TRM** | **26%** | **24.5%** | **24.5%** |
| **Selections** | | | |
| Hatch 1-2 Upgrade | 58 | 58 | 58 |
| Vogtle 1-2 Upgrade | 52 | 52 | 52 |
| McIntosh CC Upgrade | 194 | 194 | 194 |
| WTR B1 (MG0-111) | - | - | - |
| WTR B2 (MG0-111) | 55 | - | - |
| WTR B3 (MG0-111) | 55 | - | 55 |
| WTR B4 (MG0-111) | 25 | 25 | 25 |
| Bowen [136] | Retire 2032 | Retire 2032 | Co-fire |
| Scherer | Co-fire | Co-fire | Co-fire |
| 2029-2031 RFP Take | 7,836 | 6,071 | 2,519 |
| **Total MW** | **8,275** | **6,400** | **2,902** |

[136] Co-fire compliance pathway assumes continued operations through 2038. Retire 2032, assumes an early retirement compliance alternative

Staff's MG0-111 Aurora results are consistent with the Company's Unit Retirement Study discussed above, in which Staff removed the transmission constraints[137] and found that it was a close call between deciding to retire Bowen in 2032 versus co-firing.[138] Staff's 111 GHG rule Aurora analysis continues to verify that the nuclear and McIntosh upgrades should be accepted but raises questions concerning the economics of the WTR capacity. The results also demonstrate the decrease in the amount of RFP capacity required as load and TRM constraints are reduced.

**Future RFPs and Procurements**

**Q. WHAT ARE STAFFS RECOMMENDATIONS REGARDING THE COMPANY'S ALL SOURCE RFP RESOURCE OPTIONS?**

A. While Staff determined that the Company's capacity need <u>by 2031</u> is expected to be 5,226 MW (see Table 4b above), based on Staff's load forecast, TRM, and other modeling assumptions, Staff recommends the Company be authorized to acquire resources to satisfy its 2033 capacity need early. In other words, Staff recommends the Company be authorized to acquire 5,989 MW <u>by 2033</u>, through the 2029-2031 All Source RFP. This approach will allow the Company the flexibility to make plans and be able to adjust its plans to meet its capacity needs as load growth materializes. This will also allow the Company more time to adapt to the changing regulatory environment and impacts caused by supply chain issues.

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[137] Staff's Aurora modeling is consistent with the Company's Aurora Mix methodology and excludes transmission. Therefore, Staff results are most comparable to Staff's evaluation in Table 24. Additionally, Staff's Aurora modeling eliminated the need for an "out-of-model" term equalization adjustment.

[138] Staff's modeling of the co-firing and conversion options reflected the Company's URS dispatch, which did not appear to have an hourly FT limit included in the co-firing options for Bowen and Scherer 111 compliance. STF-JKA-3-20 addresses the difficulties associated with modeling co-firing logic accurately within Aurora.

By satisfying its 2033 capacity need early, the Company will likely be able to defer its next RFP process by one or more years. In addition, the Company should consider relying on an optimal portfolio expansion analysis in future RFPs.

**Q. SHOULD DSM AND DEMAND RESPONSE RESOURCES BE ALLOWED TO COMPETE IN FUTURE ALL SOURCE PROCUREMENTS?**

A. Yes. DSM and Demand Response resources may be cost-effective options for addressing future system energy and demand needs. The Company's Supply Side Case filed in the DSM evaluation in this proceeding showed that DSM resources can be effectively modeled as selectable resources and that there is significant remaining potential for cost-effective DSM. Future RFPs should allow for DSM and Demand Response bids.

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

A. Yes, it does.

**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **GEORGIA POWER COMPANY'S 2025 INTEGRATED RESOURCE PLAN** | ) ) | **DOCKET NO. 56002** |
| **GEORGIA POWER COMPANY'S 2025 APPLICATION FOR THE CERTIFICATION, DECERTIFICATION, AND AMENDED DEMAND-SIDE MANAGEMENT PLAN** | ) ) ) ) | **DOCKET NO. 56003** |

# EXHIBITS

**ON BEHALF OF THE**

**GEORGIA PUBLIC SERVICE COMMISSION**
**PUBLIC INTEREST ADVOCACY STAFF**

**MAY 5, 2025**

**EXHIBIT**

**STF-NHSW-1 - Tom Newsome Resume**

**Exhibit STF-NHSW-1**
**Tom Newsome Qualifications**

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 twenty-four Georgia Power Company ("Company" or "Georgia Power") proceedings before the Commission.

Mr. Newsome's most recent testimony was in Docket 55378 in 2023 IRP Update. Prior to that, Mr. Newsome testified Docket 29849 in 28$^{th}$ Vogtle Construction Monitoring ("VCM"). Prior to that, Mr. Newsome testified in Docket 44902 Fuel Cost Recovery (FCR-26). Prior to that Mr. Newsome's testified in Docket 29849 26$^{th}$ and 27$^{th}$ VCMs. Prior to that Mr. Newsome testified in Docket 44160 Integrated Resources Planning on supply side resources. Prior to that Mr. Newsome testified in Docket 29849 23rd Vogtle Construction Monitoring ("VCM"), 24th VCM and 25th VCM on Vogtle economics. Prior to that was testimony in 22nd VCM and in Docket 43011 Fuel Cost Recovery (FCR-25) on the Company's hedging program and certain other issues. Prior to that Mr. Newsome's testified in Docket 29849 20th / 21st Vogtle Construction Monitoring ("VCM") on Vogtle economics. Prior to that Mr. Newsome's 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.

**EXHIBIT**

**STF-NHSW-2 - Philip Hayet Resume**

## 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 formed the utility consulting firm, Hayet Power Systems Consulting ("HPSC"), and worked for customers in the United States, and internationally in Australia, Japan, Singapore, Malaysia, the United Kingdom, and Vietnam. Mr. Hayet 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") and assisted on projects that required utility resource planning, analysis, and software modeling expertise. Mr. Hayet merged his firm and 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 Present:** **J. Kennedy and Associates, Inc.**
**Vice President and Principal**

- Began in 2000 as Director of Consulting.
- Became Vice President and Principal in 2015 when Hayet Power Systems Consulting merged with J. Kennedy and Associates, Inc.
- 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 2015:** **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.
- Merged with J. Kennedy and Associates, Inc. in 2015

**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.

## 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 for Consumer Services | PacifiCorp | Concerning PacifiCorp's Schedule 38 avoided cost tariff and remaining unsubscribed capacity |
| 07/05 | 03-035-14 | UT | Utah Committee for Consumer | PacifiCorp | Concerning PacifiCorp's Schedule 38 avoided cost proceeding |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | | Services | | |
| 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 |
| 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 | Wisconsin Power and Light | Certification proceeding concerning Nelson-Dewey coal-fired generating unit |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | | Group, Inc. | | |
| 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 |
| 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 |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 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 |
| 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 |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 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 |
| 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 |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 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 |
| 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 |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 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 |
| 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 |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 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 |
| 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 |
| 5/20 | 43011-U | GA | Georgia Public Service Commission Staff | Georgia Power | Georgia Power Fuel Cost Recovery Application (FCR-25) |
| 6/20 | 29849-U | GA | Georgia Public Service Commission Staff | Georgia Power | Twenty-Second Semi-Annual Vogtle Construction Monitoring Report |
| 7/20 | 17-035-61 | UT | Utah Office of Consumer Services | Rocky Mountain Power | Approval of an Export Credit Rate for Customer Generators (Primarily Rooftop Solar) |
| 9/20 | 20-035-04 | UT | Utah Office of Consumer Services | Rocky Mountain Power | Utah Rate Case |
| 10/20 | 2019-226-E | SC | South Carolina Office of Regulatory Services | Dominion Energy South Carolina | Review of DESC's 2020 IRP |
| 10/20 | 2019-227-E | SC | South Carolina Office of Regulatory Services | Lockhart Power Company | Review of Lockhart Power Company's 2020 IRP |
| 11/20 | 29849-U | GA | Georgia Public Service Commission Staff | Georgia Power | Twenty-Third Semi-Annual Vogtle Construction Monitoring Report |
| 12/20 | 20-035-01 | UT | Utah Office of Consumer Services | Rocky Mountain Power | Application for Approval of the 2020 Energy Balancing Account |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 2/21 | 2019-224 and 225-E | SC | South Carolina Office of Regulatory Services | Duke Energy Carolinas and Duke Energy Progress | Review of Duke Energy's 2020 IRP |
| 6/21 | 29849-U | GA | Georgia Public Service Commission Staff | Georgia Power | Twenty-Fourth Semi-Annual Vogtle Construction Monitoring Report |
| 9/21 | U-35927 | LA | Louisiana Public Service Commission | 1803 Electric Cooperative | Compliance with MBM Order in Conducting RFP and Acquiring Resources |
| 12/21 | 29849-U | GA | Georgia Public Service Commission Staff | Georgia Power | Twenty-Fifth Semi-Annual Vogtle Construction Monitoring Report |
| 5/22 | 44160-U | GA | Georgia Public Service Commission Staff | Georgia Power | Georgia Power's 2022 IRP Proceeding |
| 6/22 | 29849-U | GA | Georgia Public Service Commission Staff | Georgia Power | Twenty-Sixth Semi-Annual Vogtle Construction Monitoring Report |
| 12/22 | 22-035-01 | UT | Utah Office of Consumer Services | Rocky Mountain Power | Application for Approval of the 2022 Energy Balancing Account |
| 12/22 | 2022-259-E | SC | South Carolina Office of Regulatory Services | Dominion Energy South Carolina, Inc. | Mid-Period Adjustment to Increase Base Rates for the Recovery of Electric Fuel Costs |
| 1/23 | 29849-U | GA | Georgia Public Service Commission Staff | Georgia Power | Twenty-Seventh Semi-Annual Vogtle Construction Monitoring Report |
| 06/23 | 2023-9-E | SC | South Carolina Office of Regulatory Services | Dominion Energy South Carolina, Inc. | Review of DESC's 2023 IRP |
| 7/23 | 29849-U | GA | Georgia Public Service Commission Staff | Georgia Power | Twenty-Eighth Semi-Annual Vogtle Construction Monitoring Report |
| 09/23 | 2023-154-E | SC | South Carolina Office of Regulatory Services | South Carolina Public Service Authority | Review of Santee Cooper's 2023 IRP |
| 11/23 | 23-0735-E | WV | West Virginia Energy Users Group | Mon Power and Potomac Edison | Expanded Net Energy Cost proceeding. |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 12/23 | U-36974 | LA | Louisiana Public Service Commission Staff | 1803 | Calpine Capacity PPA Certification Proceeding. |
| 2/24 | 55378 | GA | Georgia Public Service Commission Staff | Georgia Power | 2023 Integrated Resource Plan Update |
| 6/24 | U-37134 | LA | Louisiana Public Service Commission Staff | 1803 | Transmission Asset Transfer |
| 7/24 | 2023-8-E and 2023-10-E | LA | South Carolina Office of Regulatory Services | Duke Energy Progress and Duke Energy Carolinas | Review of Triennial Integrated Resource Plan |
| 12/24 | 2024-00285 | KY | Kentucky Attorney General's Office | Duke Energy Progress and Duke Energy Carolinas | Duke Energy Kentucky desire to convert from an FRR entity to an RPM entity |
| 1/25 | 24-035-01 | UT | Utah Office of Consumer Services | PacifiCorp | Application for Approval of the 2023 Energy Balancing Account |
| 2/25 | 2024-00195 | VA | Old Dominion Committee for Fair Utility Rates | APCO | 2024 Fuel Factor 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 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 May 23, 2023 Proposed Rule for the State of South Carolina", on behalf of South Carolina Office of Regulatory Staff, August 2023.

**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.

**EXHIBIT**

**STF-NHSW-3 - Anthony Sandonato Resume**

**Anthony Sandonato, Sandonato Utility Regulatory Specialists, Inc.,**
**Outside Consultant to J. Kennedy and Associates, Inc.**

**<u>EDUCATION</u>**
B.S., Nuclear Engineering, North Carolina State University, 2011

**<u>EXPERIENCE</u>**

Since receiving his undergraduate degree in nuclear engineering in 2012, Mr. Sandonato has worked in the electric utility industry in the areas of energy policy, utility regulation, renewable resource evaluation, integrated resource planning, electrification, and energy efficiency program design and implementation. Mr. Sandonato started his career at ICF and worked on behalf of utilities administering both residential and commercial energy efficiency programs satisfying multiple state legislative and regulatory requirements. After that, he worked for approximately 7 years at the South Carolina Office of Regulatory Staff, starting as a Regulatory Analyst participating in water, wastewater, natural gas and electric rate proceedings and annual filings. Ultimately, He served as Deputy Director for Energy Planning and Emerging Technology, where he prepared testimony and functioned as an expert witness before the Public Service Commission of SC on matters such as annual fuel recovery, base rate cases, and integrated resource planning. Mr. Sandonato was on the Board of the Low-Level Radioactive Waste Forum and assisted the Atlantic Compact Commission ensuring compliance with federal and state laws. Mr. Sandonato spent almost two years at Laurence Berkeley National Lab where he conducted research and presented his findings on state energy efficiency policy, electrification, distribution system planning and cost recovery. During his time at the Lab he also helped administer the National Community Solar Partnership, which offered technical assistance and education to solar developers, state local and tribal government entities, NGOs, and community-based organizations. Mr. Sandonato began work as an Outside Consultant for J. Kennedy and Associates in February 2025 and provides analytical support to clients in the areas of utility resource planning, energy efficiency, electrification, cost recovery and grid modernization.

**2025 to Present**: **J. Kennedy and Associates, Inc.**
Outside Consultant (February 2025 – Present)

Performs analysis and prepares expert witness testimony on utility planning studies and economic evaluations in review of electric utility regulatory filings. Clients include State Public Service Commissions, Industrial Users Groups, and Consumer Advocacy Groups.

**2023 to 2025: Laurence Berkeley National Laboratory**
Energy Policy Researcher: (July 2023 - February 2025)

Supported the National Community Solar Partnership, through the development of tools and curricula to advance and implement community solar programs in various regulatory jurisdictions. Conducted research and presented findings on energy efficiency, grid modernization, utility planning, electrification, decarbonization, and energy policy.

**2016 to 2023**: **South Carolina Office of Regulatory Staff**
Deputy Director – Energy Planning and Emerging Technology (December 2021 – July 2023)
Senior Regulatory Manager – Energy Operations (October 2019 – December 2021)
Regulatory Analyst (September 2016 – October 2019)

Prepared and assisted in the preparation of testimony and exhibits for formal regulatory proceedings before the Public Service Commission of South Carolina. Functioned as an expert witness before the Commission on a range of electric proceedings, including annual fuel recovery, base rate cases, integrated resource planning (encompassing integrated system operations planning), transmission and facility siting, battery energy storage systems, electric vehicles, and distributed energy resources. Validated capacity expansion and production cost modeling software for utilities' integrated resource planning and evaluating energy efficiency and demand-side management programs proposed by electric utilities. Managed the Radioactive Waste program to continue compliance with the SC Atlantic Implementation Act and Atlantic Compact Law and interface with the Atlantic Compact Commission on behalf of the state of SC.

**2012 to 2016**: **ICF**
Smart Energy in Offices Engagement Lead (July 2015 – September 2016)
Analyst (February 2014 – July 2015)
Account Manager (May 2012 – July 2013)

Developed and implemented energy efficiency programs, including building operator challenges to increase building efficiency and comfort, leveraging partnerships with universities for data analysis and facilitating operator interaction. Engaged property managers and tenants in energy-saving initiatives. Managed field engagement teams conducted commercial and industrial field inspections and developed energy savings estimates. Verified technical information and savings for projects, stayed current on building and energy codes, and provided technical training to contractors. Developed training materials and techniques for energy simulation software, trained contractors on its use, and advised them on business and sales strategies related to high-efficiency HVAC and weatherization.

**2013 to 2014**: **South Carolina Energy Office**
Technical Assistance Manager

Helped develop the Technical Assistance Program for the State Energy Office by offering Energy Assessments to Government entities outlining areas. Evaluated energy savings calculations for State grants and loans.

## CLIENTS SERVED

Georgia Public Service Commission Staff
Kentucky Industrial Utility Customers, Inc.
Louisiana Public Service Commission Staff
South Carolina Office of Regulatory Staff

## TESTIMONY AND EXPERT WITNESS APPEARANCES

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 04/18 | 2016-384-E | SC | South Carolina Office of Regulatory Staff | Moore Sewer | Adjustment of Rates and Charges and Modification to Certain Terms and Conditions for the Provision of Collection-Only Sewer Service |
| 08/18 | 2018-197-E | SC | South Carolina Office of Regulatory Staff | Dominion Energy South Carolina, Inc. f/k/a South Carolina Electric & Gas Company | Certificate of Environmental Compatibility and Public Convenience and Necessity |
| 10/18 | 2018-5-G | SC | South Carolina Office of Regulatory Staff | Dominion Energy South Carolina, Inc. f/k/a South Carolina Electric & Gas Company | Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies |
| 02/19 | 2018-319-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Carolinas, LLC | Adjustments in Electric Rate Schedules and Tariffs and Request for an Accounting Order |
| 03/19 | 2018-318-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Progress, LLC | Adjustments in Electric Rate Schedules and Tariffs and Request for an Accounting Order |
| 03/19 | 2019-2-E | SC | South Carolina Office of Regulatory Staff | Dominion Energy South Carolina, Inc. f/k/a South Carolina Electric & Gas Company | Annual Review of Base Rates for Fuel Costs |
| 10/19 | 2019-5-G | SC | South Carolina Office of Regulatory Staff | Dominion Energy South Carolina, Inc. f/k/a South Carolina Electric & Gas | Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | | | Company | |
| 01/20 | 2019-290-WS | SC | South Carolina Office of Regulatory Staff | Blue Granite Water Company | Approval to Adjust Rate Schedules and Increase Rates |
| 03/20 | 2020-2-E | SC | South Carolina Office of Regulatory Staff | Dominion Energy South Carolina, Inc. | Annual Review of Base Rates for Fuel Costs |
| 05/20 | 2020-1-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Progress, LLC | Annual Review of Base Rates for Fuel Costs |
| 07/20 | 2019-226-E | SC | South Carolina Office of Regulatory Staff | Dominion Energy South Carolina, Inc. | 2020 Integrated Resource Plan |
| 08/20 | 2020-3-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Carolinas, LLC | Annual Review of Base Rates for Fuel Costs |
| 10/20 | 2019-227-E | SC | South Carolina Office of Regulatory Staff | Lockhart Power Company | 2020 Integrated Resource Plan |
| 10/20 | 2020-5-G | SC | South Carolina Office of Regulatory Staff | Dominion Energy South Carolina, Inc. | Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies |
| 11/20 | 2020-125-E | SC | South Carolina Office of Regulatory Staff | Dominion Energy South Carolina, Inc. | Adjustments of Rates and Charges |
| 03/21 | 2019-224-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Carolinas, Inc | 2020 Integrated Resource Plan |
| 03/21 | 2019-225-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Progress, Inc | 2020 Integrated Resource Plan |
| 09/21 | 2021-3-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Carolinas, LLC | Annual Review of Base Rates for Fuel Costs |
| 06/22 | 2022-93-E | SC | South Carolina Office of Regulatory Staff | SR Lambert I, LLC | Certificate of Environmental Compatibility and Public Convenience and Necessity |
| 06/22 | 2022-97-E | SC | South Carolina Office of Regulatory Staff | SR Lambert II, LLC | Certificate of Environmental Compatibility and Public Convenience and Necessity |
| 12/22 | 2022-254-E | SC | South Carolina Office of | Duke Energy Progress, LLC | Application for an Increase in Electric Rates, Adjustments in Electric Rate Schedules and Tariffs, and Request for |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | | Regulatory Staff | | an Accounting Order |
| 02/23 | 2022-239-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Carolinas, LLC | Determinations Regarding Balancing Area Competitive Procurement of Renewable Energy Framework and 2022 Solar Procurement Program |
| 02/23 | 2022-240-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Progress, LLC | Determinations Regarding Balancing Area Competitive Procurement of Renewable Energy Framework and 2022 Solar Procurement Program |
| 05/23 | 2021-93-E | SC | South Carolina Office of Regulatory Staff | Dominion Energy South Carolina, Inc. | Request for "Like Facility" Determinations Pursuant to S.C. Code Ann. § 58-33-110(1) and Waiver of Certain Requirements of Commission Order No. 2007-626 |
| 05/23 | 2022-158-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Carolinas, LLC and Duke Energy Progress, LLC | Electric Vehicle Make Ready Credit Program |
| 05/23 | 2022-159-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Carolinas, LLC and Duke Energy Progress, LLC | Electric Vehicle Supply Equipment Program |

## REPORTS AND INDUSTRY PUBLICATIONS

| Date | Title | Author(s) |
|---|---|---|
| 07/20 | Review of Dominion Energy South Carolina, Inc.'s 2020 Integrated Resource Plan Docket No. 2019-226-E | South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc. |
| 10/20 | Review of Lockhart Power Company's 2020 Integrated Resource Plan Docket No. 2019-227-E | South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc. |
| 03/21 | Review of Duke Energy Carolinas, Inc.'s 2020 Integrated Resource Plan Docket No. 2019-224-E | South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc. |
| 03/21 | Review of Duke Energy Progress Inc.'s 2020 Integrated Resource Plan Docket No. 2019-225-E | South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc. |

| Date | Title | Author(s) |
|---|---|---|
| 06/24 | Community Solar for Opportunity States: An exploration of development models for community solar projects in states that lack explicit enabling policies | LBNL - Sandonato, Anthony, Bentham Paulos, Greg Leventis |
| 01/25 | Unlocking load growth at the grid edge: Practices for managing, recovering, and allocating distribution system investments | LBNL - Pereira, Guillermo, Jeff Deason, Anthony Sandonato |
| 01/25 | Reimagining Energy Efficiency Resource Standards | LBNL - Frick, Natalie Mims, Angela Long, Grace Relf, Anthony Sandonato |

## PRESENTATIONS

- Sandonato, A and Frick, N.M. "Updating Energy Efficiency Resource Standards." Presented at ACEEE conference, October 2023
- Sandonato, A "The National Community Solar Partnership." Presented to NASUCA, November 2023
- Sandonato, A and Schwartz, L. "Regulator challenges with cost recovery for grid modernization." Presented at IEEE Power & Energy Society Innovative Smart Grid Technologies Conference, February 2024
- Sandonato, A and Schwartz, L. "Regulator challenges with cost recovery for grid modernization." Presented to NARUC Electric Vehicle States Working Group, May 2024

## OTHER EXPERIENCE

| Dates | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 1/24 | R-31106 | LA | Louisiana Public Service Commission Staff | Various | Approval of Phase II Energy Efficiency Rule and Implementation of Statewide Program (Transition) |

**EXHIBIT**

**STF-NHSW-4 - Leah Wellborn Resume**

**EDUCATION**

M.S. Operations Research, Georgia Institute of Technology, 2017
B.S. Mathematics, Georgia Southern University, 2012

**PROFESSIONAL AFFILIATIONS**

Women's Energy Network, Greater Atlanta Chapter – Board Member (2019 – 2023)
Women's Energy Network, Greater Atlanta Chapter – Member (2016 – Present)

**EXPERIENCE**

Ms. Wellborn has been working in regulated energy markets since early 2013. She has an undergraduate degree in mathematics and graduate degree in operations research. She started her career working at J. Kennedy and Associates, Inc., and sub-contracting to Hayet Power Systems Consulting. For these companies, she provided critical support in the areas of production cost modeling and data analysis through 2018. Ms. Wellborn then spent nearly 3 years at Accenture, supporting its global regulated energy team within the procurement practice, helping large commercial and industrial clients manage their energy spend and energy related initiatives, as they related to regulated utility tariffs, economic dispatch, planning, and market risk (energy efficiency, green tariffs, PPA/VPPA, etc.). Ms. Wellborn rejoined J. Kennedy and Associates in late 2021, and currently provides analytical support to clients in the areas of utility resource planning and market modeling.

**2021 to Present**: **J. Kennedy and Associates, Inc.**
Manager, Consulting (October 2021 – Present)

Performs analysis and prepares expert witness testimony on utility planning studies and economic evaluations in review of electric utility regulatory filings. Clients include State Public Service Commissions, Industrial Users Groups, and Consumer Advocacy Groups.

**2019 to 2021**: **Accenture, LLP**
Associate Manager, Global Team, Regulated (March 2021 - October 2021)
Sourcing Specialist, International Teams Lead (March 2020 - March 2021)
Senior Analyst, Regulated Energy Procurement (January 2019 - March 2020)

As a part of Accenture Operations' Energy Management and Procurement practice, the Regulated Energy team helps clients identify opportunities for electricity and natural gas cost savings through data analysis and deep industry experience. Clients include large industrial and commercial end-use customers with locations spread across multiple geographies and utility service territories.

• Conducts tariff optimization analysis and ad hoc economic decision analysis for clients with operations and energy spend in areas served by regulated electricity and natural gas distribution utilities.

• Leads cross functional international delivery team of 10, providing career counseling and project oversight. Supports international energy procurement functions as they relate to regulated utilities/energy markets of Australia, Southeast Asia, and Latin America.
• Manages project assessments and economic studies as they relate to resource planning or capacity/energy market risk and dispatch pricing (renewables, time-of-use tariffs, real-time-pricing/avoided cost, PPA, VPPA, etc.)
• Collaborates with all energy management work streams - including utility bill management, renewable energy procurement, deregulated markets competitive sourcing, market intelligence, and project management/technology development initiatives to manage customer spend end to end.

**2013 to 2019**: **J. Kennedy and Associates, Inc.**
Senior Consultant (January 2016 – January 2019)
Consultant (March 2013 – December 2015)

Responsible for conducting research, performing data analysis, developing production-cost model input assumptions and running production-cost studies, analyzing model output, and conducting related economic studies.

## CERTIFICATIONS

Energy Exemplar – Aurora Core Certification Course (March 2022)
Energy Exemplar – PLEXOS Power Core Certification Course (June 2023)

## CLIENTS SERVED

Georgia Public Service Commission Staff
Kentucky Industrial Utility Customers, Inc.
Kentucky Office of the Attorney General
Louisiana Public Service Commission Staff
Ohio Energy Group
South Carolina Office of Regulatory Staff
Utah Office of Consumer Services
West Virginia Energy Users Group
Wisconsin Industrial Energy Group

## TESTIMONY AND EXPERT WITNESS APPEARANCES

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 06/18 | 29849 | GA | Georgia Public Service Commission Staff | Georgia Power | Eighteenth Semi-Annual Vogtle Construction Monitoring Report |
| 11/18 | 29849 | GA | Georgia Public Service Commission Staff | Georgia Power | Nineteenth Semi-Annual Vogtle Construction Monitoring Report |
| 5/22 | 44160 | GA | Georgia Public Service Commission Staff | Georgia Power | 2022 Integrated Resource Plan (Supply Side Resource Plan, Aurora) |
| 10/22 | 44280 | GA | Georgia Public Service Commission Staff | Georgia Power | 2022 Rate Case (Revenue Forecast) |
| 8/23 | 2023-9-E | SC | South Carolina Office of Regulatory Staff | Dominion Energy South Carolina, Inc. | 2023 Integrated Resource Plan |
| 12/23 | 2023-154-E | SC | South Carolina Office of Regulatory Staff | South Carolina Public Service Authority (Santee Cooper) | 2023 Integrated Resource Plan |
| 12/23 | U-36974 | LA | Louisiana Public Service Commission Staff | 1803 Electric Cooperative, Inc. | Certification of a Capacity Purchase Agreement |
| 2/24 | 55378 | GA | Georgia Public Service Commission Staff | Georgia Power | 2023 Integrated Resource Plan Update (Supply Side Resource Plan, Aurora) |
| 7/24 | 2023-8-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Progress, LLC | 2023 Integrated Resource Plan |
| 7/24 | 2023-10-E | SC | South Carolina Office of Regulatory Staff | Duke Energy Carolinas, LLC | 2023 Integrated Resource Plan |
| 8/24 | 24-0508-EL-ATA | OH | Ohio Energy Group | Ohio Power Company | Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers |
| 11/24 | 2024-00243 | KY | Office of the Attorney General & Kentucky Industrial Utility Customers | Kentucky Power Company | Renewable Energy Purchase Agreement |

| Date | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 12/24 | 24-0611-E-T-PW | WV | West Virginia Energy Users Group | Appalachian Power Co. / Wheeling Power Co. | Application for Approval of Revisions to Schedules LCP and IP (Data Centers) |

## REPORTS AND INDUSTRY PUBLICATIONS

| Date | Title | Author(s) |
|---|---|---|
| 8/23 | Review of EPA's Section 111 May 23, 2023 Proposed Rule for the State of South Carolina | J. Kennedy and Associates, Inc. (On behalf of the South Carolina Office of Regulatory Staff) |
| 7/24 | Review of Dominion Energy South Carolina, Inc.'s 2024 Integrated Resource Plan Update Docket No. 2024-9-E | South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc. |
| 1/25 | Review of Santee Cooper's 2024 Integrated Resource Plan Update Docket No. 2024-18-E | South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc. |

## OTHER EXPERIENCE

| Dates | Case | Jurisdict | Party | Utility | Subject |
|---|---|---|---|---|---|
| 1/24 | R-31106 | LA | Louisiana Public Service Commission Staff | Various | Approval of Phase II Energy Efficiency Rule and Implementation of Statewide Program (Transition) |
| 3/25 | 2024-00326 | KY | Kentucky Industrial Utility Customers | Kentucky Utilities / Louisville Gas & Electric | 2024 Joint Integrated Resource Plan (Comments) |

**STF-NHSW-5 - Reserve Margin Tables**

## Case 1 MG0 - GPC Starting Position
## GPC Load, 26% TRM, Not Accounting for 2023 IRP Update BESS RFP 500 MW

| Year | | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Georgia Power Peak Demand (MW)** | * | 16,264 | 16,892 | 18,334 | 20,320 | 22,168 | 23,612 | 24,469 | 24,900 | 25,213 | 25,451 | 25,653 | 25,768 | 25,987 | 26,216 | 26,605 | 26,917 |
| Existing and Approved Gen Cap | | 14,306 | 15,164 | 16,545 | 16,801 | 16,265 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 12,759 | 12,759 | 12,759 | 12,110 | 12,110 |
| Scherer 1 - 2 Extension beyond 2035 | | | | | | | | | | | | | - | - | - | - | - |
| Scherer 3 Extension beyond 2028 | | | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| Bowen 1 - 4 Extension beyond 2035 | | | | | | | | | | | | | 0 | 0 | 0 | 0 | 0 |
| Gaston 1-4 Extension beyond 2028 | | | | | | - | - | - | - | - | - | 0 | 0 | 0 | 0 | 0 | 0 |
| Gaston A (CT) Extension beyond 2028 | | | | | | - | - | - | - | - | - | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF EXIST AND APPROVED CAP** | **A** | 14,306 | 15,164 | 16,545 | 16,801 | 16,265 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 12,759 | 12,759 | 12,759 | 12,110 | 12,110 |
| Scherer 3 Wholesale-To-Retail | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| McIntosh CT Uprates (1-8) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| McIntosh CC Uprates (10-11) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hatch 1-2 Uprates | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Vogtle 1-2 Uprate | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Goat Rock 3-6 Hydro Inc. Cap | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF 2025 INC RESOURCE REQUESTS** | **B** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF GENERIC RESOURCE ADDITIONS** | **C** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **TOTAL OWNED GENERATING CAPACITY** | **D = A+B+C** | **14,306** | **15,164** | **16,545** | **16,801** | **16,265** | **16,266** | **16,266** | **16,266** | **16,266** | **16,266** | **16,266** | **12,759** | **12,759** | **12,759** | **12,110** | **12,110** |
| Purchased Generating Capacity (MW) | | 5,913 | 6,012 | 6,242 | 6,503 | 5,223 | 5,330 | 3,287 | 3,287 | 3,232 | 3,229 | 1,912 | 1,330 | 1,263 | 914 | 914 | 554 |
| 2022 IRP Planned ESS | | 0 | 0 | 0 | 0 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| 2023 IRP UPDATE BESS RFP | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF PURCH GEN CAP (MW)** | **E**** | **5,913** | **6,012** | **6,242** | **6,503** | **5,723** | **5,830** | **3,787** | **3,787** | **3,732** | **3,729** | **2,412** | **1,830** | **1,763** | **1,414** | **1,414** | **1,054** |
| Existing Programs (CVR, DPEC, RTP, TempCheck) | | 649 | 652 | 656 | 656 | 659 | 661 | 665 | 667 | 670 | 673 | 675 | 676 | 681 | 703 | 711 | 720 |
| DER Customer Program | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Staff Assumed Additional Demand Response | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM DISPATCHABLE DSOs (MW)** | **F ***** | **649** | **652** | **656** | **656** | **659** | **661** | **665** | **667** | **670** | **673** | **675** | **676** | **681** | **703** | **711** | **720** |
| **TOTAL CAPACITY (MW)** | **G = D+E+F** | **20,868** | **21,829** | **23,443** | **23,960** | **22,647** | **22,757** | **20,719** | **20,721** | **20,668** | **20,668** | **19,353** | **15,265** | **15,203** | **14,875** | **14,235** | **13,884** |
| **GPC TRM** | | 24.6% | 24.6% | 24.6% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% |
| **Cap Required to Meet GPC Target (MW)** | ******** | (602) | (781) | (598) | 1,467 | 5,093 | 6,790 | 9,900 | 10,438 | 10,881 | 11,180 | 12,747 | 16,980 | 17,316 | 17,930 | 19,057 | 19,799 |
| 2029-2031 RFP TARGET (Take through 2033) | | | | | 1,467 | 5,093 | 6,790 | 9,900 | 10,438 | 10,881 | 10,881 | 10,881 | 10,881 | 10,881 | 10,881 | 10,881 | 10,881 |
| 2032-2033 RFP TARGET | | | | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033+ NEEDS | | | | | | | | | | | 299 | 1,866 | 6,099 | 6,435 | 7,049 | 8,176 | 8,918 |
| **GPC Reserve Margin (%)** | | 28.3% | 29.2% | 27.9% | 17.9% | 2.2% | -3.6% | -15.3% | -16.8% | -18.0% | -18.8% | -24.6% | -40.8% | -41.5% | -43.3% | -46.5% | -48.4% |

*Territorial Load requirements less non-dispatchable DSOs

**Includes territorial and imported power purchases. Capacity does include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update.

*** Values stated in combustion turbine equivalence terms

****Reflects Staff's view of GPC TRM resulting from the system TRM of 24% (2025-2027) and 24.5% (2028 and beyond).

## Case 2 MG0 - GPC with Near Term Resources
## GPC Load, 26% TRM, 2025 IRP Requests, Extensions, Not Accounting for 2023 IRP Update BESS RFP 500 MW or Thermostat DR

| Year | | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Georgia Power Peak Demand (MW)** | * | 16,264 | 16,892 | 18,334 | 20,320 | 22,168 | 23,612 | 24,469 | 24,900 | 25,213 | 25,451 | 25,653 | 25,768 | 25,987 | 26,216 | 26,605 | 26,917 |
| Existing and Approved Gen Cap | | 14,306 | 15,164 | 16,545 | 16,801 | 16,265 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 12,759 | 12,759 | 12,759 | 12,110 | 12,110 |
| Scherer 1 - 2 Extension beyond 2035 | | | | | | | | | | | | | - | - | - | - | - |
| Scherer 3 Extension beyond 2028 | | | | | | 537 | 537 | 482 | 458 | 458 | 458 | 458 | - | - | - | - | - |
| Bowen 1 - 4 Extension beyond 2035 | | | | | | | | | | | | | 0 | 0 | 0 | 0 | 0 |
| Gaston 1-4 Extension beyond 2028 | | | | | | 460 | 460 | 460 | 460 | 460 | 460 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gaston A (CT) Extension beyond 2028 | | | | | | 10 | 10 | 10 | 10 | 10 | 10 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF EXIST AND APPROVED CAP** | **A** | 14,306 | 15,164 | 16,545 | 16,801 | 17,272 | 17,273 | 17,218 | 17,194 | 17,194 | 17,194 | 16,724 | 12,759 | 12,759 | 12,759 | 12,110 | 12,110 |
| Scherer 3 Wholesale-To-Retail | | 0 | 52 | 52 | 52 | 52 | 107 | 162 | 187 | 187 | 187 | 187 | 187 | 187 | 187 | 0 | 0 |
| McIntosh CT Uprates (1-8) | | 0 | 0 | 0 | 0 | 28 | 37 | 47 | 56 | 65 | 74 | 74 | 74 | 74 | 74 | 74 | 74 |
| McIntosh CC Uprates (10-11) | | 0 | 0 | 0 | 0 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 |
| Hatch 1-2 Uprates | | 0 | 0 | 0 | 0 | 0 | 28 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 |
| Vogtle 1-2 Uprate | | 0 | 0 | 0 | 0 | 7 | 14 | 34 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 |
| Goat Rock 3-6 Hydro Inc. Cap | | 0 | 0 | 0 | 0 | 4 | 13 | 22 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 |
| **SUM OF 2025 INC RESOURCE REQUESTS** | **B** | 0 | 52 | 52 | 52 | 285 | 394 | 517 | 575 | 584 | 594 | 594 | 594 | 594 | 594 | 407 | 407 |
| **SUM OF GENERIC RESOURCE ADDITIONS** | **C** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **TOTAL OWNED GENERATING CAPACITY** | **D = A+B+C** | **14,306** | **15,216** | **16,597** | **16,853** | **17,557** | **17,667** | **17,735** | **17,769** | **17,778** | **17,787** | **17,318** | **13,352** | **13,352** | **13,352** | **12,517** | **12,517** |
| Purchased Generating Capacity (MW) | | 5,913 | 6,012 | 6,242 | 6,503 | 5,223 | 5,330 | 3,287 | 3,287 | 3,232 | 3,229 | 1,912 | 1,330 | 1,263 | 914 | 914 | 554 |
| 2022 IRP Planned ESS | | 0 | 0 | 0 | 0 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| 2023 IRP UPDATE BESS RFP | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF PURCH GEN CAP (MW)** | **E**** | **5,913** | **6,012** | **6,242** | **6,503** | **5,723** | **5,830** | **3,787** | **3,787** | **3,732** | **3,729** | **2,412** | **1,830** | **1,763** | **1,414** | **1,414** | **1,054** |
| Existing Programs (CVR, DPEC, RTP, TempCheck) | | 649 | 652 | 656 | 656 | 659 | 661 | 665 | 667 | 670 | 673 | 675 | 676 | 681 | 703 | 711 | 720 |
| DER Customer Program | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Staff Assumed Additional Demand Response | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM DISPATCHABLE DSOs (MW)** | **F ***** | **649** | **652** | **656** | **656** | **659** | **661** | **665** | **667** | **670** | **673** | **675** | **676** | **681** | **703** | **711** | **720** |
| **TOTAL CAPACITY (MW)** | **G = D+E+F** | **20,868** | **21,881** | **23,495** | **24,012** | **23,939** | **24,158** | **22,188** | **22,223** | **22,180** | **22,189** | **20,404** | **15,859** | **15,797** | **15,469** | **14,642** | **14,290** |
| **GPC TRM** | | 24.6% | 24.6% | 24.6% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% |
| **Cap Required to Meet GPC Target (MW)** | **** | (602) | (833) | (650) | 1,415 | 3,801 | 5,389 | 8,431 | 8,936 | 9,369 | 9,659 | 11,696 | 16,386 | 16,722 | 17,336 | 18,650 | 19,392 |
| 2029-2031 RFP TARGET (Take through 2033) | | | | | 1,415 | 3,801 | 5,389 | 8,431 | 8,936 | 9,369 | 9,369 | 9,369 | 9,369 | 9,369 | 9,369 | 9,369 | 9,369 |
| 2032-2033 RFP TARGET | | | | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033+ NEEDS | | | | | | | | | | | 289 | 2,327 | 7,017 | 7,353 | 7,967 | 9,280 | 10,023 |
| **GPC Reserve Margin (%)** | | 28.3% | 29.5% | 28.2% | 18.2% | 8.0% | 2.3% | -9.3% | -10.8% | -12.0% | -12.8% | -20.5% | -38.5% | -39.2% | -41.0% | -45.0% | -46.9% |

*Territorial Load requirements less non-dispatchable DSOs
**Includes territorial and imported power purchases. Capacity does include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update.
*** Values stated in combustion turbine equivalence terms
****Reflects Staff's view of GPC TRM resulting from the system TRM of 24% (2025-2027) and 24.5% (2028 and beyond).

## Case 3 111-MG0 - GPC with Near Term Resources
## GPC Load, 26% TRM, 2025 IRP Requests, Extensions, Not Accounting for 2023 IRP Update BESS RFP 500 MW or Thermostat DR

| Year | | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Georgia Power Peak Demand (MW)** | * | 16,264 | 16,892 | 18,334 | 20,320 | 22,168 | 23,612 | 24,469 | 24,900 | 25,213 | 25,451 | 25,653 | 25,768 | 25,987 | 26,216 | 26,605 | 26,917 |
| Existing and Approved Gen Cap | | 14,306 | 15,164 | 16,545 | 16,801 | 16,265 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 12,759 | 12,759 | 12,759 | 12,110 | 12,110 |
| Scherer 1 - 2 Extension beyond 2035 | | | | | | | | | | | | | 147 | 147 | 147 | - | - |
| Scherer 3 Extension beyond 2028 | | | | | | 537 | 537 | 482 | 458 | 458 | 458 | 458 | 458 | 458 | 458 | - | - |
| Bowen 1 - 4 Extension beyond 2035 | | | | | | | | | | | | | 3,360 | 3,360 | 3,360 | 0 | 0 |
| Gaston 1-4 Extension beyond 2028 | | | | | | 460 | 460 | 460 | 460 | 460 | 460 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gaston A (CT) Extension beyond 2028 | | | | | | 10 | 10 | 10 | 10 | 10 | 10 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF EXIST AND APPROVED CAP** | **A** | 14,306 | 15,164 | 16,545 | 16,801 | 17,272 | 17,273 | 17,218 | 17,194 | 17,194 | 17,194 | 16,724 | 16,724 | 16,724 | 16,724 | 12,110 | 12,110 |
| Scherer 3 Wholesale-To-Retail | | 0 | 52 | 52 | 52 | 52 | 107 | 162 | 187 | 187 | 187 | 187 | 187 | 187 | 187 | 0 | 0 |
| McIntosh CT Uprates (1-8) | | 0 | 0 | 0 | 0 | 28 | 37 | 47 | 56 | 65 | 74 | 74 | 74 | 74 | 74 | 74 | 74 |
| McIntosh CC Uprates (10-11) | | 0 | 0 | 0 | 0 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 |
| Hatch 1-2 Uprates | | 0 | 0 | 0 | 0 | 0 | 28 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 |
| Vogtle 1-2 Uprate | | 0 | 0 | 0 | 0 | 7 | 14 | 34 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 |
| Goat Rock 3-6 Hydro Inc. Cap | | 0 | 0 | 0 | 0 | 4 | 13 | 22 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 |
| **SUM OF 2025 INC RESOURCE REQUESTS** | **B** | 0 | 52 | 52 | 52 | 285 | 394 | 517 | 575 | 584 | 594 | 594 | 594 | 594 | 594 | 407 | 407 |
| **SUM OF GENERIC RESOURCE ADDITIONS** | **C** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **TOTAL OWNED GENERATING CAPACITY** | **D = A+B+C** | **14,306** | **15,216** | **16,597** | **16,853** | **17,557** | **17,667** | **17,735** | **17,769** | **17,778** | **17,787** | **17,318** | **17,317** | **17,317** | **17,317** | **12,517** | **12,517** |
| Purchased Generating Capacity (MW) | | 5,913 | 6,012 | 6,242 | 6,503 | 5,223 | 5,330 | 3,287 | 3,287 | 3,232 | 3,229 | 1,912 | 1,330 | 1,263 | 914 | 914 | 554 |
| 2022 IRP Planned ESS | | 0 | 0 | 0 | 0 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| 2023 IRP UPDATE BESS RFP | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF PURCH GEN CAP (MW)** | **E**** | **5,913** | **6,012** | **6,242** | **6,503** | **5,723** | **5,830** | **3,787** | **3,787** | **3,732** | **3,729** | **2,412** | **1,830** | **1,763** | **1,414** | **1,414** | **1,054** |
| Existing Programs (CVR, DPEC, RTP, TempCheck) | | 649 | 652 | 656 | 656 | 659 | 661 | 665 | 667 | 670 | 673 | 675 | 676 | 681 | 703 | 711 | 720 |
| DER Customer Program | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Staff Assumed Additional Demand Response | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM DISPATCHABLE DSOs (MW)** | **F ***** | **649** | **652** | **656** | **656** | **659** | **661** | **665** | **667** | **670** | **673** | **675** | **676** | **681** | **703** | **711** | **720** |
| **TOTAL CAPACITY (MW)** | **G = D+E+F** | **20,868** | **21,881** | **23,495** | **24,012** | **23,939** | **24,158** | **22,188** | **22,223** | **22,180** | **22,189** | **20,404** | **19,824** | **19,762** | **19,434** | **14,642** | **14,290** |
| **GPC TRM** | | 24.6% | 24.6% | 24.6% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% | 25.1% |
| **Cap Required to Meet GPC Target (MW)** | **** | (602) | (833) | (650) | 1,415 | 3,801 | 5,389 | 8,431 | 8,936 | 9,369 | 9,659 | 11,696 | 12,421 | 12,757 | 13,371 | 18,650 | 19,392 |
| 2029-2031 RFP TARGET (Take through 2033) | | | | | 1,415 | 3,801 | 5,389 | 8,431 | 8,936 | 9,369 | 9,369 | 9,369 | 9,369 | 9,369 | 9,369 | 9,369 | 9,369 |
| 2032-2033 RFP TARGET | | | | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033+ NEEDS | | | | | | | | | | | 289 | 2,327 | 3,052 | 3,388 | 4,002 | 9,280 | 10,023 |
| **GPC Reserve Margin (%)** | | 28.3% | 29.5% | 28.2% | 18.2% | 8.0% | 2.3% | -9.3% | -10.8% | -12.0% | -12.8% | -20.5% | -23.1% | -24.0% | -25.9% | -45.0% | -46.9% |

*Territorial Load requirements less non-dispatchable DSOs
**Includes territorial and imported power purchases. Capacity does include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update.
*** Values stated in combustion turbine equivalence terms
****Reflects Staff's view of GPC TRM resulting from the system TRM of 24% (2025-2027) and 24.5% (2028 and beyond).

## Case 4 MG0 - Staff Starting Position
## Staff 1 LRM Uniform Load, 24.5% TRM, With 2023 IRP Update BESS RFP 500 MW

| Year | | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Staff Uniform Peak Demand Case (MW)** | * | 16,176 | 16,614 | 17,659 | 19,157 | 20,574 | 21,743 | 22,459 | 22,826 | 23,093 | 23,297 | 23,474 | 23,585 | 23,799 | 24,024 | 24,406 | 24,718 |
| Existing and Approved Gen Cap | | 14,306 | 15,164 | 16,545 | 16,801 | 16,265 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 12,759 | 12,759 | 12,759 | 12,110 | 12,110 |
| Scherer 1 - 2 Extension beyond 2035 | | | | | | | | | | | | | - | - | - | - | - |
| Scherer 3 Extension beyond 2028 | | | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| Bowen 1 - 4 Extension beyond 2035 | | | | | | | | | | | | | 0 | 0 | 0 | 0 | 0 |
| Gaston 1-4 Extension beyond 2028 | | | | | | - | - | - | - | - | - | 0 | 0 | 0 | 0 | 0 | 0 |
| Gaston A (CT) Extension beyond 2028 | | | | | | - | - | - | - | - | - | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF EXIST AND APPROVED CAP** | **A** | 14,306 | 15,164 | 16,545 | 16,801 | 16,265 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 12,759 | 12,759 | 12,759 | 12,110 | 12,110 |
| Scherer 3 Wholesale-To-Retail | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| McIntosh CT Uprates (1-8) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| McIntosh CC Uprates (10-11) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hatch 1-2 Uprates | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Vogtle 1-2 Uprate | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Goat Rock 3-6 Hydro Inc. Cap | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF 2025 INC RESOURCE REQUESTS** | **B** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF GENERIC RESOURCE ADDITIONS** | **C** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **TOTAL OWNED GENERATING CAPACITY** | **D = A+B+C** | **14,306** | **15,164** | **16,545** | **16,801** | **16,265** | **16,266** | **16,266** | **16,266** | **16,266** | **16,266** | **16,266** | **12,759** | **12,759** | **12,759** | **12,110** | **12,110** |
| Purchased Generating Capacity (MW) | | 5,913 | 6,012 | 6,242 | 6,503 | 5,223 | 5,330 | 3,287 | 3,287 | 3,232 | 3,229 | 1,912 | 1,330 | 1,263 | 914 | 914 | 554 |
| 2022 IRP Planned ESS | | 0 | 0 | 0 | 0 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| 2023 IRP UPDATE BESS RFP | | 0 | 0 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| **SUM OF PURCH GEN CAP (MW)** | **E**** | **5,913** | **6,012** | **6,742** | **7,003** | **6,223** | **6,330** | **4,287** | **4,287** | **4,232** | **4,229** | **2,912** | **2,330** | **2,263** | **1,914** | **1,914** | **1,554** |
| Existing Programs (CVR, DPEC, RTP, TempCheck) | | 649 | 652 | 656 | 656 | 659 | 661 | 665 | 667 | 670 | 673 | 675 | 676 | 681 | 703 | 711 | 720 |
| DER Customer Program | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Staff Assumed Additional Demand Response | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM DISPATCHABLE DSOs (MW)** | **F ***** | **649** | **652** | **656** | **656** | **659** | **661** | **665** | **667** | **670** | **673** | **675** | **676** | **681** | **703** | **711** | **720** |
| **TOTAL CAPACITY (MW)** | **G = D+E+F** | **20,868** | **21,829** | **23,943** | **24,460** | **23,147** | **23,257** | **21,219** | **21,221** | **21,168** | **21,168** | **19,853** | **15,765** | **15,703** | **15,375** | **14,735** | **14,384** |
| **STF TRM** | | 23.1% | 23.1% | 23.1% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% |
| **Cap Required to Meet GPC Target (MW)** | ******** | (952) | (1,374) | (2,201) | (773) | 2,292 | 3,628 | 6,551 | 7,004 | 7,386 | 7,639 | 9,173 | 13,398 | 13,724 | 14,330 | 15,443 | 16,180 |
| 2029-2031 RFP TARGET (Take through 2033) | | | | | (773) | 2,292 | 3,628 | 6,551 | 7,004 | 7,386 | 7,386 | 7,386 | 7,386 | 7,386 | 7,386 | 7,386 | 7,386 |
| 2032-2033 RFP TARGET | | | | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033+ NEEDS | | | | | | | | | | | 252 | 1,786 | 6,012 | 6,338 | 6,944 | 8,057 | 8,794 |
| **GPC Reserve Margin (%)** | | 29.0% | 31.4% | 35.6% | 27.7% | 12.5% | 7.0% | -5.5% | -7.0% | -8.3% | -9.1% | -15.4% | -33.2% | -34.0% | -36.0% | -39.6% | -41.8% |

*Territorial Load requirements less non-dispatchable DSOs
**Includes territorial and imported power purchases. Capacity does include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update.
*** Values stated in combustion turbine equivalence terms
****Reflects Staff's view of GPC TRM resulting from the system TRM of 24% (2025-2027) and 24.5% (2028 and beyond).

## Case 5 MG0 - Staff with Near Term Resources
### Staff 1 LRM Uniform Load, 24.5% TRM, Staff Recommendations, With 2023 IRP Update BESS RFP 500 MW and Thermostat DR

| Year | | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Staff Uniform Peak Demand Case (MW)** | * | 16,176 | 16,614 | 17,659 | 19,157 | 20,574 | 21,743 | 22,459 | 22,826 | 23,093 | 23,297 | 23,474 | 23,585 | 23,799 | 24,024 | 24,406 | 24,718 |
| Existing and Approved Gen Cap | | 14,306 | 15,164 | 16,545 | 16,801 | 16,265 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 16,266 | 12,759 | 12,759 | 12,759 | 12,110 | 12,110 |
| Scherer 1 - 2 Extension beyond 2035 | | | | | | | | | | | | | 147 | 147 | 147 | 147 | 147 |
| Scherer 3 Extension beyond 2028 | | | | | | 537 | 537 | 482 | 458 | 458 | 458 | 458 | 458 | 458 | 458 | 458 | 458 |
| Bowen 1 - 4 Extension beyond 2035 | | | | | | | | | | | | | 3,360 | 3,360 | 3,360 | 3,360 | 3,360 |
| Gaston 1-4 Extension beyond 2028 | | | | | | 460 | 460 | 460 | 460 | 460 | 460 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gaston A (CT) Extension beyond 2028 | | | | | | 10 | 10 | 10 | 10 | 10 | 10 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF EXIST AND APPROVED CAP** | **A** | 14,306 | 15,164 | 16,545 | 16,801 | 17,272 | 17,273 | 17,218 | 17,194 | 17,194 | 17,194 | 16,724 | 16,724 | 16,724 | 16,724 | 16,076 | 16,076 |
| Scherer 3 Wholesale-To-Retail | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| McIntosh CT Uprates (1-8) | | 0 | 0 | 0 | 0 | 28 | 37 | 47 | 56 | 65 | 74 | 74 | 74 | 74 | 74 | 74 | 74 |
| McIntosh CC Uprates (10-11) | | 0 | 0 | 0 | 0 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 |
| Hatch 1-2 Uprates | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 |
| Vogtle 1-2 Uprate | | 0 | 0 | 0 | 0 | 7 | 14 | 34 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 |
| Goat Rock 3-6 Hydro Inc. Cap | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUM OF 2025 INC RESOURCE REQUESTS** | **B** | 0 | 0 | 0 | 0 | 229 | 245 | 275 | 332 | 371 | 381 | 381 | 381 | 381 | 381 | 381 | 381 |
| **SUM OF GENERIC RESOURCE ADDITIONS** | **C** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **TOTAL OWNED GENERATING CAPACITY** | **D = A+B+C** | **14,306** | **15,164** | **16,545** | **16,801** | **17,501** | **17,519** | **17,493** | **17,526** | **17,565** | **17,574** | **17,105** | **17,105** | **17,105** | **17,105** | **16,456** | **16,456** |
| Purchased Generating Capacity (MW) | | 5,913 | 6,012 | 6,242 | 6,503 | 5,223 | 5,330 | 3,287 | 3,287 | 3,232 | 3,229 | 1,912 | 1,330 | 1,263 | 914 | 914 | 554 |
| 2022 IRP Planned ESS | | 0 | 0 | 0 | 0 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| 2023 IRP UPDATE BESS RFP | | 0 | 0 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| **SUM OF PURCH GEN CAP (MW)** | **E**** | **5,913** | **6,012** | **6,742** | **7,003** | **6,223** | **6,330** | **4,287** | **4,287** | **4,232** | **4,229** | **2,912** | **2,330** | **2,263** | **1,914** | **1,914** | **1,554** |
| Existing Programs (CVR, DPEC, RTP, TempCheck) | | 649 | 652 | 656 | 656 | 659 | 661 | 665 | 667 | 670 | 673 | 675 | 676 | 681 | 703 | 711 | 720 |
| DER Customer Program | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Staff Assumed Additional Demand Response | | 0 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| **SUM DISPATCHABLE DSOs (MW)** | **F ***** | **649** | **750** | **754** | **754** | **757** | **759** | **763** | **765** | **768** | **771** | **773** | **774** | **779** | **801** | **809** | **818** |
| **TOTAL CAPACITY (MW)** | **G = D+E+F** | **20,868** | **21,927** | **24,041** | **24,558** | **24,481** | **24,608** | **22,544** | **22,578** | **22,565** | **22,574** | **20,789** | **20,209** | **20,147** | **19,819** | **19,179** | **18,828** |
| **STF TRM** | | 23.1% | 23.1% | 23.1% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% | 23.7% |
| **Cap Required to Meet GPC Target (MW)** | **** | (952) | (1,472) | (2,299) | (871) | 958 | 2,278 | 5,226 | 5,646 | 5,989 | 6,233 | 8,236 | 8,954 | 9,280 | 9,886 | 10,999 | 11,736 |
| 2029-2031 RFP TARGET (Take through 2033) | | | | | (871) | 958 | 2,278 | 5,226 | 5,646 | 5,989 | 5,989 | 5,989 | 5,989 | 5,989 | 5,989 | 5,989 | 5,989 |
| 2032-2033 RFP TARGET | | | | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033+ NEEDS | | | | | | | | | | | 243 | 2,247 | 2,964 | 3,291 | 3,897 | 5,010 | 5,746 |
| **GPC Reserve Margin (%)** | | 29.0% | 32.0% | 36.1% | 28.2% | 19.0% | 13.2% | 0.4% | -1.1% | -2.3% | -3.1% | -11.4% | -14.3% | -15.3% | -17.5% | -21.4% | -23.8% |

*Territorial Load requirements less non-dispatchable DSOs
**Includes territorial and imported power purchases. Capacity does include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update.
*** Values stated in combustion turbine equivalence terms
****Reflects Staff's view of GPC TRM resulting from the system TRM of 24% (2025-2027) and 24.5% (2028 and beyond).

**STF-NHSW-6 - Generic Resource Comparison**

# Exhibit STF-NHSW-6
# Generic Resource Costs[139]

Certain Information considered confidential to the utility has been omitted from STF-NHSW-6 tables where cells are intentionally left blank.
Staff escalated other utilities and public sources to 2030$ using a 2.3% escalation rate.

| Combustion Turbine | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | GPC 2025 IRP | GPC 2023 IRP Update | LG&E/KU 2024 IRP | Santee Cooper 2024 IRP Update | DESC 2025 IRP Update | DESC 2025 IRP Update | EIA AEO 2025 | NREL ATB 2024 Mod | Entergy NOLA 2024 IRP | Ind. Mich. Pwr Comp. 2024 IRP | TVA Draft 2025 IRP | Duke Energy Indiana 2024 IRP |
| | CT w SCR | CT w SCR | | H-Class | 1x0 Adv. Greenfield Frame CT | 2x0 Greenfield F Class | Industrial Frame | F Class | Frame CT | F Class | Frame CT | |
| **Year Availability** | 2029 | | 2030 | 2031 | | | 2026 | | | 2030 | 2029 | 2031 |
| **Dollar Year** | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 |
| **Capacity (MW)** | [redacted] | [redacted] | 258 | 402 | 450 | 402 | 419 | 233 | 408 | 240 | 884 | 425 |
| **Capital Cost ($/kW)** | [redacted] | [redacted] | 1,636 | 1,919 | 1,494 | 1,650 | 907 | 1,311 | 1,330 | 1,500 | 853 | 1,146-1,375 |
| **Fixed O&M ($/kW-yr.)** | [redacted] | [redacted] | 6.90 | 5.85 | | | 7.99 | 31.19 | 7.93 | 9.31 | 6.30 | |
| **Variable O&M ($/MWh)** | [redacted] | [redacted] | | 11.23 | | | 4.64 | 8.32 | 10.14 | 5.98 | | |
| **Average Heat Rate (MBTU/MWh)** | [redacted] | [redacted] | 9,500 | 9,386 | | | 9,142 | 9,717 | 9,450 | 9,910 | 10,087 | |

[139] Sources used for the following tables: Entergy NOLA 2024 IRP, EIA AEO 2025 Preliminary Results, DESC 2024 IRP Update, NREL 2024 ATB, Lazard LCOE 2024, Santee Cooper 2024 IRP Update, Duke Supplemental Planning Analysis ("SPA") 2023 IRP, TVA Draft 2025 IRP, 2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, and Indiana Michigan power Company Stakeholder Meeting #2.

Exhibit STF-NHSW-6
Generic Resource Comparison
REDACTED

| Combined Cycle | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | GPC 2025 IRP | GPC 2023 IRP Update | LG&E/KU 2024 IRP | LG&E/KU CPCN | LG&E/KU CPCN | Santee Cooper 2024 IRP Update | | DESC 2025 IRP Update | EIA AEO 2025 | Lazard 2024 LCOE | Lazard 2024 LCOE | NREL ATB 2024 | Entergy NOLA 2024 IRP | Ind. Mich. Pwr Comp. 2024 IRP | Duke Energy Indiana 2024 IRP | Duke Indiana CPCN |
| | NGCC 1x1 | | NGCC | Brown 12 | Mill Creek 6 | 1x1 H Class | 1x1 F Class | 1x1 Greenfield | Single-Shaft | (Low) (New Build) | (High) (New Build) | H Frame | | | | Cayuga CC |
| **Year Availability** | | | 2030 | 2030 | 2031 | 2031 | 2031 | | 2027 | | | | | 2031 | 2030 | |
| **Dollar Year** | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 |
| **Capacity (MW)** | [redacted] | [redacted] | 660 | 660 | 660 | 630 | 357 | 665 | 627 | 550 | 550 | 649 | 729 | 420 | 719 | 1,476 |
| **Capital Cost ($/kW)** | [redacted] | [redacted] | 2,121 | 2,120 | 2,138 | 1,949 | 3,010 | 2,337 | 1,003 | 974 | 1,490 | 1,752 | 1,520 | 1,955 | 1,662-1,777 | 2,597 |
| **Fixed O&M ($/kW-yr.)** | [redacted] | [redacted] | 7.80 | 7.80 | 7.10 | 8.91 | 13.47 | | 18.05 | 11.46 | 29.23 | 46.78 | 14.75 | 19 | | |
| **Variable O&M ($/MWh)** | [redacted] | [redacted] | 0.23 | 0.23 | 0.23 | 3.27 | 3.78 | | 3.89 | 3.15 | 5.73 | 3.00 | 5.83 | 3 | | |
| **Average Heat Rate (MBTU/MWh)** | [redacted] | [redacted] | 6,300 | 6,300 | 6,300 | 6,136 | 6,668 | | 6,226 | 6,750 | 7,500 | 6,068 | 6,759 | 6,430 | | |

| Combined Cycle with CCS | | | | | | |
|---|---|---|---|---|---|---|
| | **GPC 2025 IRP** | | **GPC 2023 IRP Update** | **TVA 2025 IRP Draft** | **Ind. Mich. Pwr Comp. 2024 IRP** | **Duke Energy Indiana 2024 IRP** |
| | **Local CCS** | **Distant CCS** | | | | |
| **Year Availability** | 2037 | 2037 | | 2033 | 2035 | 2035 |
| **Dollar Year** | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 |
| **Capacity (MW)** | [redacted] | | | 1,430 | 380 | 1,215 |
| **Capital Cost ($/kW)** | | | | 3,458 | 3,838 | 4,298 |
| **Fixed O&M ($/kW-yr.)** | | | | 107.75 | 36 | |
| **Variable O&M ($/MWh)** | | | | 5.73 | 8 | |
| **Average Heat Rate (MBTU/MWh)** | | | | 7,832 | 7,120 | |

| On-Shore Wind | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **GPC 2025 IRP** | **GPC 2023 IRP Update** | **Santee Cooper 2024 IRP Update** | **Duke Energy Indiana 2024 IRP** | **EIA AEO 2025** | **NREL ATB 2024 (Mod)** | **Entergy NOLA 2024 IRP** | **Lazard 2024 LCOE (Low)** | **Lazard 2024 LCOE (High)** | **Indiana Michigan Power Company 2024 IRP** |
| **Year Availability** | 2033 | 2032 | 2029 | 2028 | 2027 | | | | | 2028 |
| **Dollar Year** | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 |
| **Capacity (MW)** | [redacted] | | 50 | 50 | 200 | 200 | 100-200 | 250 | 250 | 200 |
| **Capital Cost ($/kW)** | | | 2,236 | 2,350 | 1,864 | 1,776 | 2,357 | 1,490 | 2,178 | 3,140 |
| **Fixed O&M ($/kW-yr.)** | | | 55.41 | | 38.45 | 38.38 | 49.99 | 28.08 | 45.85 | 10.04 |

| Solar | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **GPC 2025 IRP** | **GPC 2023 IRP Update** | **Santee Cooper 2024 IRP Update** | **Duke Energy Indiana 2024 IRP** | **DESC 2025 IRP Update** | **EIA AEO 2025** | **NREL ATB 2024 (Mod)** | **Entergy NOLA 2024 IRP** | **Lazard 2024 LCOE (Low)** | **Lazard 2024 LCOE (High)** | **TVA Draft 2025 IRP** | **LG&E/KU Utility-Scale Solar 2024 IRP** | **Indiana Michigan Power Company 2024 IRP** |
| **Year Availability** | 2028 | 2027 | 2026 | 2027 | | 2026 | | | | | 2027 | | 2028 |
| **Dollar Year** | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 |
| **Capacity (MW)** | [redacted] | [redacted] | 50 | 50 | 100 | 150 | 100 | 100 | 150 | 150 | 50 | 100 | 150 |
| **Capital Cost ($/kW)** | [redacted] | [redacted] | 1,781 | 2,120 | 1,826 | 1,581 | 1,654 | 2,188 | 974 | 1,605 | 1,490 | 1,902 | 2,616 |
| **Fixed O&M ($/kW-yr.)** | [redacted] | [redacted] | 27.30 | | | 26.26 | 26.39 | 15.36 | 12.61 | 16.05 | | 17.00 | 10.04 |

| Battery Storage (4 Hour) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **GPC 2025 IRP** | **GPC 2023 IRP Update** | **Santee Cooper 2024 IRP Update (4 Hour)** | **Duke Energy Indiana 2024 IRP (4 Hour)** | **DESC 2025 IRP Update (4 Hour)** | **EIA AEO 2025 (4 Hour)** | **NREL ATB 2024 (Mod) (4 Hour)** | **Entergy NOLA 2024 IRP (4 Hour)** | **TVA Draft 2025 IRP** | **LG&E/KU 2024 IRP (4 Hour)** | **Indiana Michigan Power Company 2024 IRP (4 Hour)** |
| **Year Availability** | 2028 | | 2026 | 2028 | | 2025 | | | 2029 | 2028 | 2028 |
| **Dollar Year** | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 | 2030 |
| **Capacity (MW)** | [redacted] | [redacted] | 50 | 50 | 100 | 150 | 60 | 50/200 | 50 | 100+ | 50 |
| **Capital Cost ($/kW)** | [redacted] | [redacted] | 2,132 | 2,636 | 2,281 | 1,811 | 2,123 | 2,734 | 1,656 | 2,049 | 2,093 |
| **Fixed O&M ($/kW-yr.)** | [redacted] | [redacted] | 53.29 | | | 46.56 | 52.78 | 17.34 | 53.42 | 25.00 | 54.57 |

| Battery Storage (MDESS) | | |
|---|---|---|
| | GPC 2025 IRP | GPC 2023 IRP Update |
| Year Availability | 2033 | 2033 |
| Dollar Year | 2030 | 2030 |
| Capacity (MW) | [redacted] | |
| Capital Cost ($/kW) | | |
| Fixed O&M ($/kW-yr.) | | |

| Nuclear (AP-1000) | | |
|---|---|---|
| | GPC 2025 IRP Nuclear (AP-1000) | TVA 2025 IRP Draft Adv. Pressurized Water Reactor |
| Year Availability | 2037 | 2038 |
| Dollar Year | 2030 | 2030 |
| Capacity (MW) | [redacted] | 1,150 |
| Capital Cost ($/kW) | | 14,818 |
| Fixed O&M ($/kW-yr) | | 146.60 |
| Variable O&M ($/MWh) | | 1.51 |
| Average Heat Rate (MBTU/MWh) | | 10,132 |

**STF-NHSW-7 - Revenue Requirement Comparison**

| GPC Request Capital Expenditure ($ million) | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2026-2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Bowen U1-4: ELG - Operate thru 2043 (MG0) | [redacted] | | | | | | | | | | |
| Scherer U1-3: ELG – Operate thru 2043 (MG0) | | | | | | | | | | | |
| Gaston U1-4, A; Retire by 12/31/2034 | | | | | | | | | | | |
| McIntosh CT Upgrade | | | | | | | | | | | |
| McIntosh CC Upgrade | | | | | | | | | | | |
| Hatch 1-2 Capital Additions | | | | | | | | | | | |
| Vogtle 1-2 Capital Additions | | | | | | | | | | | |
| Wholesale to Retail Capacity | | | | | | | | | | | |
| Hydro Modernization | | | | | | | | | | | |
| DSM (GPC Proposed Case) | | | | | | | | | | | |
| Transmission | | | | | | | | | | | |
| Distribution | | | | | | | | | | | |
| **Total** | 1,569 | 1,426 | 1,479 | 1,197 | 2,869 | 1,083 | 226 | 725 | 83 | 90 | 10,747 |

**Exhibit STF-NHSW-7**
**Revenue Requirement Comparison**
**REDACTED**

| GPC Request Revenue Requirement ($ million) | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2026-2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Bowen U1-4: ELG - Operate thru 2043 (MG0)[140] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Scherer U1-3: ELG – Operate thru 2043 (MG0)[141] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Gaston U1-4, A; Retire by 12/31/2034 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| McIntosh CT Upgrade | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| McIntosh CC Upgrade | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Hatch 1-2 Capital Additions | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Vogtle 1-2 Capital Additions | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Wholesale to Retail Capacity | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Hydro Modernization | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| DSM (GPC Proposed Case) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Transmission | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Distribution | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total** | **917** | **1,088** | **1,245** | **1,358** | **1,796** | **1,917** | **1,972** | **2,084** | **2,068** | **2,045** | **16,491** |

140 Excludes O&M and FT revenue requirements
141 *Id.*