PUBLIC DISCLOSURE

STATE OF GEORGIA

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:

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**

REBUTTAL TESTIMONY OF

JEFFREY R. GRUBB, J. RANDY HUBBERT, M. BRANDON LOONEY, MICHAEL B. ROBINSON, AND FRANCISCO VALLE

JUNE 9, 2025

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REBUTTAL TESTIMONY OF JEFFREY R. GRUBB, J. RANDY HUBBERT, M. BRANDON LOONEY, MICHAEL B. ROBINSON, AND FRANCISCO VALLE

IN SUPPORT OF GEORGIA POWER COMPANY'S 2025 INTEGRATED RESOURCE PLAN DOCKET NO. 56002

AND

APPLICATION FOR THE CERTIFICATION, DECERTIFICATION, AND AMENDED DEMAND SIDE MANAGEMENT PLAN DOCKET NO. 56003

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.

A. My name is Jeffrey R. Grubb. I am the Director of Resource Planning for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. My name is James "Randy" Hubbert. I am the Southern Company Services ("SCS") Resource Planning Director. My business address is 600 North 18th Street, Birmingham, Alabama 35203.

A. My name is Michael "Brandon" Looney. I am the Reliability Planning Manager for SCS. My business address is 600 North 18th Street, Birmingham, Alabama 35203.

A. My name is Michael B. Robinson. I am the Vice President for Grid Transformation for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. My name is Francisco Valle. I am the Director of Forecasting and Analytics for SCS. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

Q. DID THIS PANEL PREVIOUSLY PRESENT DIRECT TESTIMONY ON BEHALF OF GEORGIA POWER IN THESE PROCEEDINGS?

A. Yes.

Q. WHAT IS THE PURPOSE OF THE PANEL'S REBUTTAL TESTIMONY?

A. The purpose of our testimony is to respond to the testimony of the Georgia Public Service Commission ("Commission") Public Interest Advocacy Staff ("Staff") and various Intervenors filed in Docket Nos. 56002 and 56003. Due to the number of parties filing testimony in this case and the limited time available to file rebuttal, our testimony focuses on several key issues without attempting to address every issue or recommendation raised in Staff or Intervenor testimony. However, the fact that the Company may not respond to a particular position of Staff or an Intervenor should not be construed as acceptance of such position.

Q. PLEASE SUMMARIZE THE REBUTTAL TESTIMONY OF THE PANEL.

A. Our rebuttal testimony addresses Georgia Power's responses to certain Staff and Intervenor critiques and recommendations regarding: the Company's Load and Energy Forecast; the Reserve Margin Study; scenario design, expansion planning, and Resource Mix Study; the Renewable Integration Study; proposed nuclear unit upgrades; transmission planning; and the Company's wholesale-to-retail offer.

Regarding the Company's Load and Energy forecast, Staff and Intervenors inappropriately focus on negative trends in Georgia Power's quarterly large load economic development reports, claiming that the Company fails to incorporate updated data in the Load Realization Model ("LRM"). Specifically, Staff and Intervenors selective focus on how cancelled projects and load reductions are

reflected in the forecast. However, these arguments fail to appreciate that the Company already provides the most up to date snapshot of load data in every quarterly report and each iteration of its Load and Energy Forecast. Staff's extrapolation of data across quarterly reports results in double counting of load trends. Staff and Intervenor critiques focus on load removals without considering that for every load reduction in the pipeline there is an equal or greater addition to the large load pipeline. The Company's forecasting approach, which considers both load removals and additions, leads to a more reasonable estimation of the load the Company will be required to serve. Staff and Intervenors also conflate load materialization with project success in the LRM, which further skews their proposed adjustments and recommendations.

The Company acknowledges that there have been changes to the large load economic development pipeline since Q2 2024, when the Load and Energy Forecast was prepared, and the Company has prepared a February 2025 Load and Energy Forecast based on the February 2025 sensitivity provided in response to Hearing Request ("HR") 1-1 with proposed revisions to the LRM shown in Exhibit 1 to this testimony. To evaluate the impact of Staff's proposed "Uniform Adjustment" to treat data center materialization the same as other commercial customers, the Company ran a sensitivity with the Uniform Adjustment with the increased large load economic development pipeline seen in the February 2025 sensitivity. Applying Staff's Uniform Adjustment to the updated February 2025 pipeline results in a large load forecast that is more than 2,200 MW greater than the Company's February 2025 LRM sensitivity, and higher in all years except 2025-2026. The Company does not recommend approval of Staff's Uniform Adjustment but is seeking Commission approval of the Company's revised load and energy forecast, updated with more recent data and revised assumptions. The Company recommends that its February 2025 Load and Energy Forecast be approved in this case and used to determine procurement needs during the 2029-2031 All-Source Request for Proposals ("RFP") certification proceeding.

Regarding the Company's Reserve Margin Study, Staff recommends lowering the Company's Winter Target Reserve Margin ("TRM") from 26% to 24.5%. However, adopting Staff's lower Winter TRM could lead to serious reliability concerns. These concerns are more than just hypothetical—utilities across the country have dealt with reliability issues in recent years and months, impacting thousands of customers. The cost required to maintain a higher reserve margin is justified and reasonable in light of the significant costs to customers if Georgia Power were not able to serve customer load. The Company's recommended Winter and Summer TRMs, which are based on the same general methodology as previous Integrated Resource Plans ("IRPs"), have served customers well during recent storms. Reducing the Winter TRM to 24.5% as Staff suggests would result in Georgia Power falling below the industry practice one in ten-year reliability threshold while also reducing Georgia Power's reliability to levels lower than other states with which the state of Georgia competes for economic development.

Regarding the Company's generation expansion plan modeling, Staff and Intervenors level criticisms at the Company's expansion plan modeling as if the Company's resource decisions are being made in this, and previous, case(s) based solely on the modeling results. The Company's expansion plan included in the 2025 IRP indicates what may be an optimal mix of resources within various future scenarios and does not represent a decision or commitment for specific resources. Georgia Power supports the use of practical modeling assumptions that are reflective of the real and significant resource decisions that the Company will subsequently make subject to the Commission's approval. Therefore, the Company employs the industry practice of implementing reasonable build limit assumptions, based on prior experience and knowledge, as part of its expansion planning. Finally, while Staff and Intervenors criticized the Company's assumed costs for combined cycle ("CC") and combustion turbine ("CT") resources, the Company's analysis shows that these resources are still part of an economically optimal mix of resources even when higher prices are assumed.

The Company's requested upgrades to the existing generation fleet support the optimization of resources that already exist for the economic benefit of customers, and the Commission should support the Company's requested natural gas and nuclear unit upgrades as proposed and as scheduled. Staff recommends a two-year delay in implementing the proposed upgrades at Plant Hatch Units 1-2, assuming lessons learned from the Plant Vogtle Units 1-2 upgrades could be applied at Plant Hatch. Adopting Staff's recommendation would result in an immediate degradation of positive customer economics. Contrary to Staff's assumption, the value of any lessons learned is negligible given the Company's extensive, existing experience in upgrading nuclear units and technology differences between Plant Vogtle Units 1-2 and Plant Hatch Units 1-2. Further, delay in the Hatch Units 1-2 uprates would risk the Company's ability to secure favorable tax credits that would lower the costs for these projects for the benefit of customers.

Staff recommends denial of the Company's proposed hydro modernization program but recommends approval of $100 million to support preliminary investigation and engineering studies through 2027. Unfortunately, this proposal represents a fundamental misunderstanding of how hydro units are designed and engineered, and adoption of Staff's recommendation would result in unnecessary delay, duplicative work, and increased costs to customers. By comparison, approval of the Company's proposed hydro modernization request in this proceeding is the least-cost plan for customers and allows the Company to build on the momentum of the current hydro modernization program.

Our rebuttal testimony also responds to Staff and Intervenor testimony focused on the Company's near-term and long-term transmission related planning efforts. We reintroduce the transmission-related components of the 2025 IRP and highlight the critical importance of transmission planning in maintaining a robust and reliable electrical system. Parties recommend that Georgia Power adjust various aspects of the transmission planning process and adopt suggested improvements including multi-value transmission planning methods, formal evaluation and consideration of

grid-enhancing technologies and non-wires alternative solutions, and overarching reforms related to local, regional, and long-term transmission planning issues. We explain how the proposed reforms disregard many aspects of the Company's well-established transmission planning process and ignore planned enhancements that will further benefit customers. Through the existing framework, Georgia Power accurately evaluates transmission and generation decisions as part of the planning and procurement process. We also explain how Georgia Power engages, coordinates, and plans locally, regionally, and with neighboring systems to ensure reliable, cost-effective transmission expansion for the state of Georgia.

In summary, the Commission should approve the Company's request as filed. The 2025 IRP reasonably forecasts customer demand and proposes cost effective solutions and upgrades to resources on the Georgia Power System to help address the resulting capacity need. The Company's comprehensive approach to transmission planning and continued investment in transmission infrastructure will enable the Company to better deliver and serve customers' energy needs today, tomorrow, and for the next 20 years.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The remainder of our testimony is organized as follows:

- Section II discusses the Load and Energy Forecast.
- Section III discusses the Company's Reserve Margin Study.
- Section IV discusses the Company's scenario design, expansion planning, and Resource Mix Study.
- Section V discusses the Renewable Integration Study.
- Section VI discusses the Company's proposed unit upgrades.
- Section VII discusses transmission planning and various grid enhancing technologies.
- Section VIII discusses the Company's wholesale-to-retail offer.

Q. HAVE YOU PREPARED ANY EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A. Yes. Exhibit 1 of our testimony contains details of input assumptions that the Company proactively addressed in its February 2025 LRM sensitivity.

II. LOAD AND ENERGY FORECAST

A. Use of Quarterly Report Data

Q. PLEASE DESCRIBE THE CRITIQUES OF THE COMPANY'S USE OF DATA IN THE LRM.

A. Staff Witnesses Trokey, Drugan, and Pol made recommendations regarding the integration of the Company's quarterly large load economic development reports to improve and refine the underlying assumptions of the LRM.[1] The Staff panel also seeks to require the Company to report on how it will "evaluate and incorporate into the current LRM the data produced from all prior LRM vintages" in addition to the quarterly reports.[2]

Georgia Interfaith Power & Light ("GIPL") and Southface Energy Institute ("Southface") Witness Hotaling criticizes the Company for allegedly failing to use new data from the Company's large load quarterly reports to update its assumptions about how large load customers will behave.[3] Specifically, Witness Hotaling discusses highlights from her review of data from each of the Company's quarterly large load reports and provides information on changes observed between the first quarterly report through the fourth quarterly report.[4] Based on her analysis, Witness Hotaling concludes that Georgia Power did not update its large load model to reflect

[1] Direct Testimony of Robert L. Trokey, Dylan A. Drugan, and Karan A. Pol, Docket Nos. 56002 & 56003 (May 5, 2025) ("Trokey Panel") at 8:8–14.
[2] *Id.* at 9:20–23.
[3] Direct Testimony of Chelsea Hotaling, Docket Nos. 56002 & 56003 (May 2, 2025) ("Hotaling") at 5:21–25.
[4] *Id.* at 7:11–24.

its new data, that Georgia Power's growth assumptions are inaccurate, and that Georgia Power's reliance on these allegedly inaccurate assumptions has led to an overstated load forecast. She ultimately recommends, in part, that the Company's delay probability should be modified to reflect data from the four 2024 quarterly load reports that are available.

Q. HAS THE COMPANY FILED UPDATED DATA FOR THE LRM IN THIS CASE?

A. Yes. On April 4, 2025, the Company filed a hearing request response containing data relevant to a draft February 2025 LRM sensitivity. Exhibit 1 to our testimony contains the complete details of input assumptions that the Company proactively addressed in the February 2025 LRM sensitivity.[5] Section II.D of our testimony includes (i) a comparison of the Company's February 2025 LRM sensitivity against Staff's recommended LRM adjustments, (ii) the February 2025 Load Forecast that aggregates the February 2025 LRM sensitivity and the organic load forecast from the 2025 IRP Load and Energy Forecast, (iii) updated seasonal capacity needs for Georgia Power based on the February 2025 Load Forecast, and (iv) the Company's recommendation to adopt the February 2025 Load Forecast for use in the 2029-2031 All-Source RFP certification proceeding.

Q. WHY ARE INTERVENOR PROPOSALS TO USE DATA FROM PREVIOUS QUARTERLY REPORTS AND LRM VINTAGES NOT APPROPRIATE?

A. The Company's quarterly report provides the most up-to-date information each time it is filed. For each iteration of the quarterly report, the Company incorporates

[5] The sensitivity provided by the Company in response to HR-1-1 was a draft sensitivity. The Company has provided the finalized sensitivity as Exhibit 1. This resulted in a small change that captures the delay of commercial operations for two projects.

the latest information in its models. Therefore, each time the quarterly report gets updated, all past information in previous quarterly reports becomes obsolete.

In short, the Company's latest quarterly report already accounts for changes in new projects, load removals, and load additions. Therefore, incorporating data from previous quarterly reports into the LRM, as Staff Witnesses Trokey, Drugan, and Pol suggest, would double count these data points and lead to inaccurate conclusions. Similarly, any trends or regression analyses observed from one report to another, as discussed by GIPL/Southface Witness Hotaling, would also double count the points that are being analyzed. Put simply, there is limited value to information that is extracted from previous large load quarterly reports because it is incorporated into the most recent report.

B. Large Load Materialization

Q. WHAT ADJUSTMENTS DID STAFF PROPOSE TO THE COMPANY LOAD FORECAST?

A. Staff Witnesses Trokey, Drugan, and Pol offer several critiques to the substance of the Company's load forecast, including critiques of both the organic load forecast and the LRM. However, Staff Witnesses only identified one adjustment to the Company's load forecast, and that adjustment was to the LRM.[6] Staff proposed to alter the materialization assumption for data centers and cryptocurrency currently included in the LRM to align with the materialization assumption for other industry segments ("Uniform LRM"). Staff's Uniform LRM proposal has the effect of reducing the Company's peak load forecast by 2,000 MW through 2032.

Q. WHAT IS THE MATERIALIZATION ASSUMPTION IN THE LRM?

A. The materialization assumption in the LRM represents the difference between actual metered load versus announced load. Staff attempted to make a similar

[6] Trokey Panel at 80:2-22.

adjustment in the 2023 IRP Update, to which the Company responded that data centers are expected to use most of their connected load. As a result, the Company assigned a higher materialization percentage for data centers and cryptocurrency. In addition, consistent with past practices, the Company continues to communicate directly with large load data center customers and has used this information, as well as other factors discussed later, to inform the materialization assumption used in the LRM.

Q. DOES THE COMPANY BELIEVE IT IS APPROPRIATE TO ADJUST THE MATERIALIZATION ASSUMPTION USED FOR THE LRM AS STAFF HAS PROPOSED IN THIS CASE?

A. No. Staff Witnesses Trokey, Drugan, and Pol took a single year snapshot of three data center projects—which are still in active development—and relied upon that early load data to justify a change in the materialization assumption for all data centers. We do not agree that this small sample size of three projects still under development justifies changing the materialization assumption as proposed by Staff. As the Company explained in response to a data request in this case,[7] an additional analysis of the project materialization assumption is not appropriate at this time due to the limited sample size of large load projects that have reached the mature stage in their load ramps. The Company does agree that, when an adequate sample size of mature projects becomes available, the LRM assumptions for all industry segments should be reevaluated and adjusted, if needed.

Q. ARE THERE OTHER FACTORS THAT SUPPORT THE COMPANY'S ASSUMPTION AROUND THE MATERIALIZATION OF DATA CENTER LOADS?

A. Yes. With more than 73 data centers currently on the Company's system, the Company has significant experience with the operational characteristics and the

[7] *See* STF-DEA-7-12.

load factors of data centers. Although not a substitute for actual load materialization data, operational and load forecast data further inform the Company's materialization assumptions. In the absence of more mature data on materialization of the new large load economic development customers, this operational experience and load factor data are helpful in supporting the differentiation between the assumptions used for data centers and other industry segments.

Q. DO YOU HAVE CONCERNS WITH STAFF'S RELIANCE ON PROJECT CANCELLATIONS TO JUSTIFY THEIR PROPOSED MATERIALIZATION ADJUSTMENT?

A. Yes. Staff Witnesses Trokey, Drugan, and Pol's reference to project cancellations as support for their materialization adjustment mixes and matches two separate concepts. Project cancellations are considered as part of the "Project Success" component of the LRM and not as part of the materialization assumption. During direct hearings of Staff and Intervenors, Staff Witness Pol agreed that cancellations are accounted for in the Project Success component of the LRM and not as part of the load materialization assumption.[8] We further discuss the proper consideration of load additions and load removals in the next section of our testimony.

C. Load Additions and Load Removals

Q. PLEASE DESCRIBE INTERVENOR CRITIQUES OF THE COMPANY'S LARGE LOAD PIPELINE FORECAST.

A. Staff and certain Intervenors focus on the removals of load from the Company's LRM to argue that the Company's LRM is overstating the load that is coming to Georgia. For example, Staff Witnesses Trokey, Drugan, and Pol state that "[w]hile the [large load pipeline] continues to add new projects and loads, it also documents

[8] Tr. 77 (Intervenor Hearing Day 1). Note that citations to the Staff and Intervenor hearings on May 27–29, 2025, are based on the rough draft of the transcript provided by the court reporter.

numerous project removals and load reductions,"[9] and in light of the "significant rate of project removals and net load reductions, modification to the assumptions of the LRM is necessary."[10] They further call for "[a]ny new load additions to the LRM" to be "treated with scrutiny, as these projects may also be removed, reduced, or otherwise adjusted as time passes."[11]

Similarly, GIPL/Southface Witness Hotaling describes the "Load Change," "Load Removed," and "Load Ramp Change" as part of her analysis of the quarterly reports submitted by Georgia Power.[12] Witness Hotaling further provides recommendations around capturing the risk of certain customers dropping out of Georgia Power's load queue.

Q. WHAT IS THE COMPANY'S RESPONSE TO THESE CRITICISMS?

A. A focus on load removals places undue emphasis on this aspect of the LRM because it fails to account for an equally, if not more, significant aspect: load additions. For every reduction in load in the Company's LRM, there has been an equal or greater load increase. As Company Witness Valle noted in direct hearings:

> For every megawatt that has been removed, 3 megawatts have been added to the pipeline. And that's why, if you look at the size of the pipeline over time, it continues to grow. So we have cancellations, but we also have additions that more than offset . . . any cancellations so far.[13]

Thus, it is necessary to consider both the load additions together with load removals. The size and scope of any additions are critical information that contextualizes load removals and informs the entire load forecast. Load additions—

[9] Trokey Panel at 62:16–18.
[10] *Id.* at 63:1–2.
[11] *Id.* at 62:18–63:1.
[12] Hotaling at 7:11–24.
[13] Direct Hearing, Tr. Vol. 1 at 298:5–10.

even if tempered by load removals—drive the Company's planning decisions because the Company must plan and build resources if its overall load increases.

Q. WHAT ARE THE POTENTIAL RESULTS OF AN OVEREMPHASIS ON LOAD REMOVALS?

A. An over emphasis on load removals without due consideration of additions to the pipeline could result in a biased load forecast. The Company's goal is to have as accurate a forecast as possible, and the Company continues its reasonable practice of revising its forecast assumptions and approach with each iteration to incorporate changes in customer demand and market conditions. Importantly, an over emphasis on any one component reduces the likelihood of producing an accurate forecast by either over-forecasting or under-forecasting load, which could increase reliability risks for customers and the System. To correct for under-forecasting load, Georgia Power might have to shed load or make expensive market purchases to serve load. Unlike the recommendations of Staff and Intervenors, the Company's approach appropriately balances the impact of load removals and load additions in the large load pipeline, leading to a more reasonable estimation of the load it will be required to serve.

Q. DOES STAFF'S PROPOSED LOAD FORECAST PROPERLY CONSIDER LOAD ADDITIONS AND LOAD REMOVALS?

A. It does not. Staff compares its proposed load forecast to the Company's February 2025 LRM sensitivity and finds that both align through 2028, with Staff's forecast showing lower loads after 2028. Staff's adjusted forecast is based upon the same large load economic development pipeline the Company used to develop the 2025 IRP, which largely aligns with the Q2 2024 Large Load Economic Development Report. This, however, is not the pipeline that was used to create the February 2025 LRM sensitivity. The February 2025 LRM sensitivity is based upon a pipeline that is more than double that of the pipeline assumed by Staff in its proposed forecast, which is the primary driver of the differential between the Company's February

2025 LRM sensitivity and Staff's proposed forecast. When load additions are appropriately considered using the pipeline from the February 2025 LRM sensitivity, Staff's Uniform LRM produces significantly higher loads than the Company's February 2025 LRM sensitivity. This is further illustrated in Section II.D.

Q. PLEASE DESCRIBE GIPL/SOUTHFACE WITNESS HOTALING'S CRITIQUE OF THE COMPANY'S ANALYSIS OF LOAD CANCELLATIONS.

A. Witness Hotaling recommends including a probability referred to as "P1A" to reflect the success rate for customers not dropping out of the new large load queue. Witness Hotaling notes that the Company's "P3 probability, or Georgia Power's probability for contract success, is included in the [LRM] to reflect the success rate of a customer materializing after a contract with Georgia Power has been signed."[14] Further, Witness Hotaling alleges that "even with a signed contract, the model does not reflect the probability of a customer leaving Georgia Power's load queue if they are considered in the technical review stage with no commitments."[15] Therefore, Witness Hotaling argues that "additional risk of these customers leaving the queue should be incorporated into the [LRM]."[16]

Q. WHAT IS THE COMPANY'S RESPONSE TO WITNESS HOTALING'S CRITICISM?

A. Witness Hotaling describes load materialization in tandem with success rates and other concepts, but each of these terms carry a distinct meaning. There is also a meaningful difference between load materialization and success rate. Load materialization accounts for the difference between the metered load being served, as measured at the customer's meter, and the load announced (or design capacity)

[14] Hotaling at 18:1–3.
[15] *Id.* at 18:4–6.
[16] *Id.* at 18:11–12.

by the customer, expressed as a percentage. Separately, the success rate for each customer is determined by incremental customer decisions toward becoming a Georgia Power customer. These decisions include selecting the state of Georgia (P1), signing a contract with Georgia Power (P2), and reaching commercial operation after the contract is signed (P3).

Further, cancellations and dropouts are already considered as part of project success in the LRM. For a new large load project to be considered successful, all three of the above events (i.e., state selection, signing a contract for electric service with Georgia Power being chosen as the electric service provider, and the project reaching commercial operation) must occur. In other words, project success or failure (dropouts and cancellations) is a binary event the probability of which is captured by the product of each of these three events (i.e., the formula P = P1*P2*P3). Therefore, accounting for additional risk, as Witness Hotaling argues, is duplicative and unnecessary.

Q. PLEASE SUMMARIZE GIPL/SOUTHFACE'S CRITICISM OF THE COMPANY'S REDUCTION TO THE LOAD FORECAST FOR DEMAND SIDE MANAGEMENT SAVINGS.

A. GIPL/Southface Witness Hotaling argues that "there was a gap in the savings between Georgia Power's DSM Plan and what was included in the IRP load forecast" and states that she adjusted for that difference in her analysis.[17] GIPL/Southface Witness Sherwood alleges that Georgia Power "used numbers that did not represent the [DSM] Proposed Case's energy and demand savings," and that the numbers used were "significantly lower than the Proposed Case," which could undercount possible Demand Side Management ("DSM") savings.

[17] *Id.* at 41:5–10.

Q. PLEASE CLARIFY HOW GEORGIA POWER REDUCES THE ENERGY AND DEMAND FORECAST FOR DSM SAVINGS BEFORE CONSIDERING SUPPLY SIDE ALTERNATIVES.

A. As an initial step in the planning process, the Company reduces the energy and demand forecast by the amount of projected savings from continuing the Company's currently approved DSM programs. As explained by Dr. Beppler of the Customer Programs Panel in the Company's direct hearing, demand response programs and dispatchable demand side options are captured as contributions to the resource plan, and energy efficiency or passive DSM is captured as a reduction to the energy forecast.[18] The Company's adjustments reflect the continuation of dispatchable demand side options and continued incremental energy savings in the energy forecast that would be generated if the Company's existing portfolio of DSM programs were to continue into the future. Therefore, a correction is needed to the statement on page 51 of the 2025 IRP Main Document where Georgia Power describes this process. The last sentence of the first paragraph in Section 7.3.2 should read as follows: "[i]n fact, the first step in the Company's IRP process is to reduce the Company's load and energy forecasts by the current DSM Plan's energy and demand impacts, prior to developing supply-side alternatives."

D. February 2025 Load Forecast

Q. HOW DID THE COMPANY'S LARGE LOAD PIPELINE CHANGE FROM Q2 2024 TO FEBRUARY 2025?

A. The Company's large load pipeline more than doubled, increasing from 22,763 MW in Q2 2024 to 48,381 MW in February 2025. Furthermore, the composition of the pipeline changed such that the amount of data center developers and data center co-locators without tenants increased relative to the other segments. This change in

[18] Direct Hearing, Tr. Vol. 2, at 853.

size and composition of the large load pipeline led the Company to proactively refine inputs in the February 2025 LRM sensitivity, as described in Exhibit 1.

Q. DID STAFF AND INTERVENORS INCORPORATE THE LATEST LARGE LOAD PIPELINE DATA IN THEIR RECOMMENDED ADJUSTMENTS TO THE COMPANY'S LOAD FORECAST?

No. Despite having access to large load data through Q4 2024[19] and February 2025,[20] Staff Witnesses Trokey, Drugan, and Pol and GIPL/Southface Witness Hotaling made their load forecast recommendations based on large load pipeline data through Q2 2024.

Q. DID STAFF CLARIFY ANY RECOMMENDATIONS TO THEIR LOAD FORECAST ADJUSTMENTS DURING THE DIRECT HEARINGS OF STAFF AND INTERVENORS?

A. Yes. Staff Witness Pol clarified that the panel's recommendation is that the Company should apply a uniform load materialization assumption to the latest pipeline:

> To be clear about our recommendations, we are recommending that the Company adjust the load materialization assumptions. Now, what we provided in our numerical adjustments are indicative based on the initial filing that the Company provided. Now, if the pipeline has changed, you would simply apply the updated assumptions to the new pipeline and continue doing that in the future unless data suggests that you need to update those values. So, I wouldn't focus on the specific adjustment values . . . . In terms of our recommendation, we simply apply those materialization assumptions again to any updated pipeline. Right, so the next time the Company performs the Load Realization Model, they would take our, assuming the Commission approves it, they would take the recommendation of uniform assumptions, plug it into the model, and run it again. So, every time the pipeline updates, yes, the forecast would update. So, if the large load pipeline is changing on a

[19] *See* STF-PIA-8-2.
[20] *See* HR-1-1.

quarterly basis, yes, the forecast would change on a quarterly basis.[21]

Q. HOW DOES STAFF'S RECOMMENDED UNIFORM LRM COMPARE TO THE COMPANY'S FEBRUARY SENSITIVITY WHEN INCORPORATING THE FEBRUARY 2025 LARGE LOAD PIPELINE?

A. Applying Staff's recommended uniform load materialization assumptions to the February 2025 pipeline results in a higher large load forecast than the Company's February 2025 LRM sensitivity in all years except 2025-2026. Significantly, by 2030, Staff's Uniform LRM adjustment updated with the February 2025 pipeline is 2,251 MW greater than the Company's February 2025 sensitivity. This difference grows over time and is illustrated for years 2025-2037 in Figure 1 below.

Figure 1: February 2025 LRM vs. Uniform LRM with February 2025 Pipeline

REDACTED

[21] Tr. 118–20 (Intervenor Hearing Day 1).

Q. WHY ARE THE COMPANY'S ADJUSTMENTS TO THE LRM INPUTS USED FOR THE FEBRUARY SENSITIVITY MORE APPROPRIATE THAN STAFF'S UNIFORM LOAD MATERIALIZATION ADJUSTMENT?

A. The Company's adjustments to the LRM inputs used for the February 2025 sensitivity are more appropriate than Staff's Uniform Adjustment for several reasons. These reasons are rooted in the dynamic nature of the large load customer portfolio and the need to evolve forecasting models to better reflect the latest available information.

The February LRM Sensitivity was developed by considering new market information that emerged after the Company prepared its 2025 IRP Load and Energy Forecast in August 2024 and filed the 2025 IRP in January 2025. Specifically, there has been a notable increase in the pipeline size and composition of data center customers, which requires adjustments to accurately reflect current conditions. Staff's Uniform Adjustment does not account for these recent developments because it relies on a modification of the 2025 IRP LRM as originally filed.

In the February 2025 LRM, the Company introduced two key changes to enhance the accuracy of the load forecast:

(1) Revised Materialization Assumptions: The Company now differentiates between types of data center customers based on their likelihood of materialization. Colocator data centers without committed tenants and data center developers are now modeled at lower materialization levels compared to hyperscalers and colocators with committed tenants. Without committed tenants, there is increased uncertainty regarding the level at which facilities will be contracted, and therefore, they are modeled at lower materialization levels. A uniform adjustment, as Staff proposes, would apply a blanket assumption that does not accurately capture these nuances and would not recognize some early evidence of hyperscalers materializing at 80% or higher.

(2) Commitment Likelihood Adjustment: The Company has shifted the commitment likelihood from the likelihood of signing a Request for Service ("RFS") to a stage-based likelihood of signing a Contract for Electric Service ("CES"). This change provides more certainty to the forecast by focusing on a more definitive stage of customer commitment. The likelihood of signing a CES is a more reliable indicator of actual load materialization than the likelihood of signing an RFS, which is an earlier and less binding stage in the customer engagement process.

In summary, the Company's adjustments are more appropriate because they incorporate recent market insights and refine the LRM to better capture the complexities and uncertainties in customer behavior, particularly in the data center sector. These changes result in a more accurate and reliable load forecast that supports the planning needs of this filing.

Q. DID THE COMPANY PRODUCE A NEW LOAD FORECAST BASED ON THE FEBRUARY 2025 LRM SENSITIVITY?

A. Yes. The Company produced the February 2025 Load Forecast, which incorporates the shaped, coincident peak of the February 2025 LRM sensitivity for large loads and the organic load from the 2025 IRP filing. Georgia Power's projected seasonal peak demands from the February 2025 Load Forecast, as compared to the 2025 IRP filing, are provided in Figure 2 below.

Figure 2: Seasonal Peak Demands (MW) – 2025 IRP and February 2025

Year	Winter 2025 IRP	Winter February 2025	Year	Summer 2025 IRP	Summer February 2025
2024/2025	16,264	16,236	2025	17,802	17,716
2025/2026	16,892	16,750	2026	18,770	18,480
2026/2027	18,334	17,808	2027	20,552	19,971
2027/2028	20,320	19,501	2028	22,730	21,981
2028/2029	22,168	21,696	2029	24,621	24,373
2029/2030	23,612	23,517	2030	25,841	25,934
2030/2031	24,469	24,769	2031	26,554	27,081
2031/2032	24,900	25,590	2032	26,895	27,789
2032/2033	25,213	26,160	2033	27,268	28,289
2033/2034	25,451	26,436	2034	27,550	28,588
2034/2035	25,653	26,623	2035	27,790	28,778
2035/2036	25,768	26,706	2036	27,939	28,918
2036/2037	25,987	26,923	2037	28,206	29,188
2037/2038	26,216	27,170	2038	28,412	29,385
2038/2039	26,605	27,548	2039	28,675	29,638
2039/2040	26,917	27,851	2040	28,839	29,795
2040/2041	27,295	28,222	2041	29,219	30,150
2041/2042	27,687	28,605	2042	29,619	30,542
2042/2043	28,118	29,028	2043	30,030	30,946
2043/2044	28,544	29,446	2044	30,514	31,419

Q. DID THE COMPANY UPDATE ITS CAPACITY NEEDS BASED ON THE FEBRUARY 2025 LOAD FORECAST?

A. Yes. The Company updated the Georgia Power information from Table 8.1B in the 2025 IRP Main Document to incorporate the February 2025 Load Forecast. A comparison of capacity needs to the 2025 IRP filing is shown in Figure 3 below.

Figure 3: Projected Capacity Needs (MW) – 2025 IRP and February 2025

Year	Winter 2025 IRP	Winter February 2025	Year	Summer 2025 IRP	Summer February 2025
2024/2025	(602)	(637)	2025	(898)	(999)
2025/2026	(781)	(957)	2026	(708)	(1,053)
2026/2027	(598)	(1,253)	2027	80	(609)
2027/2028	1,467	442	2028	2,132	1,240
2028/2029	4,086	3,495	2029	4,846	4,550
2029/2030	5,783	5,663	2030	7,568	7,679
2030/2031	8,948	9,324	2031	8,277	8,905
2031/2032	9,511	10,374	2032	8,680	9,745
2032/2033	9,954	11,139	2033	9,176	10,392
2033/2034	10,252	11,485	2034	9,522	10,758
2034/2035	12,290	13,504	2035	11,989	13,166
2035/2036	16,980	18,153	2036	16,135	17,300
2036/2037	17,316	18,487	2037	16,605	17,774
2037/2038	17,930	19,124	2038	17,069	18,228
2038/2039	19,057	20,237	2039	18,025	19,171
2039/2040	19,799	20,968	2040	18,515	19,653
2040/2041	20,284	21,444	2041	19,009	20,118
2041/2042	20,768	21,916	2042	19,484	20,583
2042/2043	21,299	22,438	2043	19,968	21,059
2043/2044	21,822	22,951	2044	20,536	21,613

Q. DOES THE COMPANY HAVE A RECOMMENDATION FOR WHICH LOAD FORECAST SHOULD BE UTILIZED IN THE 2029-2031 ALL-SOURCE RFP CERTIFICATION?

A. Yes. The Company recommends that the February 2025 Load Forecast be approved in this case and used to determine procurement needs during the 2029-2031 All-Source RFP certification proceeding. The Company's adjustments to the project success and load materialization assumptions of the LRM utilized in the February 2025 Load Forecast are more appropriate than Staff's adjustments to the load materialization assumptions applied to the February large load pipeline. The

February 2025 Load Forecast was also reflected in the capacity needs included in Georgia Power Company's Application for the Certification of the CARES 2023 Utility Scale Renewable Power Purchase Agreements filed on June 5, 2025, and will be reflected in the capacity needs included in the certification application for resources selected in Georgia Power's Winter 2027-2028 Battery Energy Storage System ("BESS") RFP.

III. RESERVE MARGIN STUDY

Q. WHAT ARE THE COMPANY'S RECOMMENDED VALUES FOR THE WINTER AND SUMMER TARGET RESERVE MARGINS?

A. The Company proposes to maintain a Winter TRM of 26% and increase the Summer TRM to 20%. For the short term (2024-2026), the Company plans to adopt System targets of 25.5% for winter and 19.5% for summer.

Q. WHAT CONCERNS ARE THERE IF THE TARGET RESERVE MARGIN IS SET TOO LOW?

A. The Company uses the reserve margin for reliability planning purposes. It is designed to minimize the combined expected costs of maintaining planning reserve capacity, production costs, and customer costs associated with service interruptions. Importantly, a reserve margin also balances these costs against risk of outages and minimum levels of reliability.

While a higher reserve margin may increase costs to customers from having more generation resources available to serve load, a reserve margin that is too low creates far greater risks in terms of reliability. During extreme weather events, like those experienced in recent years, an insufficient reserve margin could leave the Company without sufficient power to serve load. If the Company does not have sufficient resources to serve load, the Company would be required to shed firm load and curtail service to customers to prevent larger-scale blackouts. Put simply, a

lower reserve margin increases the risk of a reliability event and the loss of power to customers when they need it most.

While these scenarios may seem theoretical, utilities in the United States have confronted these reliability issues head-on in recent years and months. The brownouts—intentional load shedding—in New Orleans over Memorial Day weekend (May 25, 2025) were ordered by MISO, the area's regional transmission organization, to avoid blackouts due to increased customer demand, transmission constraints, and generation outages leading to an inability to serve load. This event impacted approximately 100,000 customers in a major metropolitan area on a late spring day, not even during the heat of the summer months to come.

In a similar vein, the shedding of firm load by some Southeastern utilities during Winter Storm Elliott on December 24, 2022, emphasized the importance of reliable service. While other utilities were forced to shed load, Georgia Power was able to avoid the same outcome due in part to its emphasis on reliability.

Although the Company recognizes there is a cost to maintain a higher reserve margin, there are also significant costs to not being able to serve customer load, many of which—school and business closures, and in extreme cases, health and safety concerns—do not show up on customer bills.

Q. HOW DOES THE COMPANY ADDRESS THESE POSSIBILITIES IN ITS RESERVE MARGIN STUDY?

A. The Company designs its Reserve Margin Study to include the cost of reliability, ensuring that the risk of significant outages such as the ones previously described are minimized. Additionally, the Company establishes a TRM that, at a minimum, meets the industry practice of no more than a projected one loss of load event every ten years ("1:10 LOLE"), while also seeking to balance the cost of generation with the cost of unserved energy.

In other words, the Company seeks to minimize the true costs of reliability to customers and maximize the benefits to customers of avoiding outages, all by ensuring the target reserve margin is appropriately set.

Q. PLEASE DESCRIBE STAFF'S CRITIQUES OF THE COMPANY'S PROPOSED WINTER TARGET RESERVE MARGIN.

A. Staff contends that the Company's proposed 26% Winter TRM is too high.[22] In support of this conclusion, Staff identifies four issues with the Company's TRM analysis. They contend: (1) the Company's Load Forecast Error ("LFE") distribution was overstated due to model errors, which allegedly overstated the TRM; (2) the Company's data center load assumptions contributed to an overstated TRM; (3) the Company's cold weather data training models resulted in overstated weather-adjusted loads for certain extremely low temperature conditions; and (4) the removal of a single month of cold weather would reduce the winter TRM to less than 24%.

Q. IS STAFF'S RECOMMENDED TARGET RESERVE MARGIN OF 24.5% APPROPRIATE?

A. No. As a preliminary matter, Staff acknowledges that the Company's recommended Winter and Summer TRMs were based on the same general methodology of prior IRPs.[23] As with these prior IRPs, the Company's proposed 26% margin has served customers well during recent storms such as Winter Storm Elliott in 2022, Winter Storm Heather in 2024, and Winter Storms Enzo and Cora in early 2025. Notwithstanding the consistency in methodology and resulting customer benefits from the Company maintaining an adequate reserve margin during significant

[22] Direct Testimony of Tom Newsome, Philip Hayet, Anthony Sandonato, and Leah Wellborn, Docket Nos. 56002 & 56003 (May 5, 2025) ("Newsome Panel") at 18–19.
[23] *Id.* at 18.

weather events, Staff recommends a 24.5% Winter TRM, similar to their recommendations in 2019 and 2022.

Staff's recommendation would result in Georgia Power falling below the 1:10 LOLE industry practice, meaning Georgia Power would be expected to have more than one reliability event every ten years. This level of reliability would place Georgia at a reliability level lower than surrounding states, which have followed Georgia Power in moving to seasonal planning and increasing winter Target Reserve Margins over the past several years. That result is unacceptable to the Company and should be to this Commission as well. Further, falling below that industry practice LOLE metric would mean that Georgia Power would be at a reliability level lower than other states with which the state of Georgia competes for economic development opportunities, putting the state at a competitive disadvantage to attract economic development opportunities.

Finally, uncertainty around the new load—uncertainty that Staff itself recognizes[24]—means that a reduction at this stage of the planning process would not be prudent. Events of unavailability of power in recent years and months show that operating electric grids is becoming more challenging. In a time of changing customer dynamics, increasing importance of electric service in everyday life, and unprecedented economic growth, a reduction in the reliability of the electric grid could lead to catastrophic results.

A. Load Forecast Error Distribution

Q. PLEASE DESCRIBE STAFF'S PROPOSAL REGARDING THE COMPANY'S LOAD FORECAST ERROR DISTRIBUTION.

A. Staff disagrees with the Company's Load Forecast Error ("LFE") methodology, the smallest risk component of the Reserve Margin Study, stating that "the LFE

[24] *See* Tr. 87 (Intervenor Hearing Day 1) (acknowledging that recent large load customers are "kind of a nascent thing, something new").

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."[25] Further, Staff contends that the Company's inclusion of forecast model statistical error "simply expanded the LFE distribution and overstated the TRM calculation,"[26] even though the Company's LFE range in this IRP is only 0.23% higher than the LFE range used in the 2022 IRP. In support of its conclusion, Staff looked to reserve margin studies for other utilities that were performed by Astrapé using its SERVM model.[27]

Q. DESPITE STAFF'S CRITICISM, IS IT APPROPRIATE TO CONSIDER MODEL ERROR IN THE LOAD FORECAST ERROR COMPONENT?

A. Yes. Load forecasts are inherently uncertain, and the LFE component of the Reserve Margin Study is designed to address this uncertainty. Even if the Company had perfect foresight into future economic conditions, it would nevertheless be impossible to produce a perfect load forecast due to the inherent imperfections of the models used to produce the forecast. Therefore, the Company represents this uncertainty as a combination of both economic uncertainty, which Staff agrees is a reasonable consideration, as well as uncertainty associated with attempting to translate economic data into forecasted customer loads. While these model errors are relatively small compared to the overall magnitude of the load forecast, it is both reasonable and appropriate to include them when considering load forecast error in the Company's Reserve Margin Study.

[25] Newsome Panel at 27:5–8.
[26] *Id.* at 27:14–15.
[27] *Id.* at 28:5–9.

Q. IS STAFF'S RELIANCE ON THE RESERVE MARGIN STUDIES FOR OTHER UTILITIES APPROPRIATE?

A. No. Importantly, Astrapé did not perform Georgia Power's Reserve Margin Study. Therefore, Astrapé's analysis for other utilities is inapplicable to Georgia Power's Reserve Margin Study. Moreover, Staff mistakenly applied a 40% adjustment factor to the LFE "to reduce the economic uncertainty factors developed by the Company, consistent with the Astrapé approach."[28] That adjustment, however, was incorrect to apply to Georgia Power's LFE because the economic forecast incorporated into Georgia Power's Reserve Margin Study was different than the GDP-based forecast used by Astrapé in the other studies. Staff's application of that adjustment factor skews the results of the LFE analysis.

Q. IS STAFF'S PROPOSED RESERVE MARGIN APPROPRIATE EVEN IN LIGHT OF ITS ATTEMPT TO REMOVE LFE?

A. No. Relying on its review of the Astrapé studies, Staff calculated an approximation of a winter TRM after removing the LFE analysis, resulting in a winter TRM of 24.6%.[29] Rather than approximating this analysis, Staff could have relied on the analysis it requested the Company perform, which was to model the results of the Company's Reserve Margin Study without the impact of LFEs. In response to STF-JKA-4-4, the Company modeled the winter TRM with the LFE set to 0%, which showed that a 25% reserve margin meets the 1:10 LOLE threshold, which Staff acknowledges is the industry standard for reliability.[30] In other words, when removing the impact of LFEs, the reserve margin is higher than Staff's recommendation.

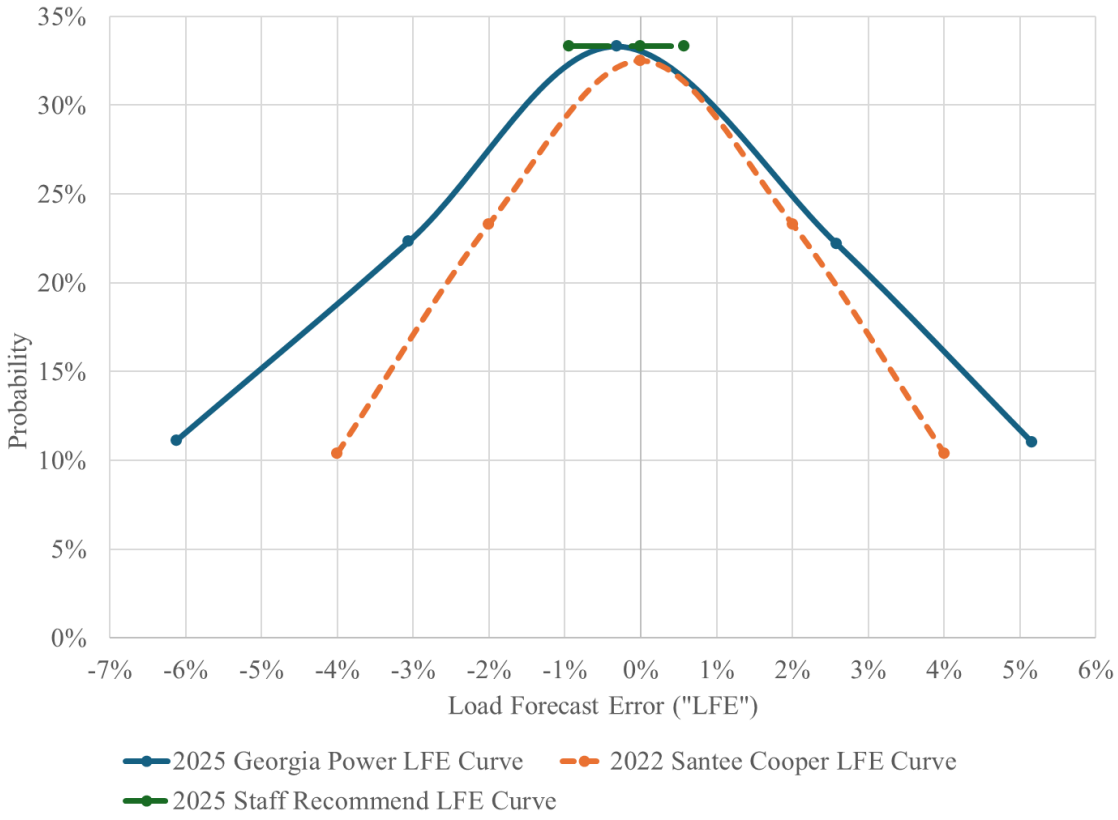
[28] *Id.* at 28:18–29:13.
[29] *Id.* at 30:1–2.
[30] *Id.* at 19; *see also* Tr. 156–57 (Intervenor Hearing Day 1) ("[T]he standard is one event occurring every ten years").

Q. IS STAFF'S PROPOSED LFE DISTRIBUTION REASONABLE?

A. No. Staff's proposed LFE distribution of -.95% to 0.57% is unreasonable, especially given that Staff developed its LFE distribution using information from various other utilities whose LFE distributions are wider than Staff's proposal. For instance, Staff highlights Santee Cooper's reserve margin study, which included an LFE distribution that ranged from -4% to +4%, which is similar to Georgia Power's LFE distribution of –6.12% to 5.16%.

Figure 4 below demonstrates the LFE distribution of Georgia Power and Santee Cooper and also includes Staff's recommendation.

Figure 4: Probabilistic Distribution of Load Forecast Errors



As illustrated above, the LFE distributions of Georgia Power and Santee Cooper, while not identical, look similar both in shape and in size. In contrast, Staff's

proposed LFE range is a mere fraction of either Georgia Power or Santee Cooper's, notwithstanding Staff's acknowledgement that Santee Cooper's LFE distribution range in its recent reserve margin study was reasonable.

B. Data Center Weather Sensitivities

Q. PLEASE DESCRIBE INTERVENOR CRITICISMS REGARDING THE WEATHER SENSITIVITY OF DATA CENTERS.

A. Staff suggests that the Company's data center load assumptions contributed to an overstatement of the Company's Winter TRM, namely, that the weather modeling approach used by the Company to adjust the base year load forecast was applied to the entirety of the load forecast even though data center loads are less weather sensitive. Accordingly, Staff argues that data centers should have received a lower adjustment to accurately reflect system impacts.

Q. HOW DOES THE COMPANY ACCOUNT FOR DATA CENTER WEATHER SENSITIVITY IN THE RESERVE MARGIN STUDY?

A. The development of the load shapes used for the Reserve Margin Study includes a model that establishes aggregate load sensitivity to temperature. The model is trained with actual temperature and load data from the most recent five-year period. Existing data center customers are present in the training data, and the model recognizes that not all customer classes have the same sensitivity to temperature. The resulting aggregate impact should represent diversity in customer class. As additional data center load materializes, the aggregate impact of temperature sensitivity will be present in the future model training data. In future Reserve Margin Studies, the Company could segregate data center load from other customer classes if the materialization of data center load and the observed temperature sensitivity justifies this change.

Q. IS THE COMPANY'S MODELING APPROACH REASONABLE?

A. The Company's modeling approach is a reasonable approach given the uncertain and nascent nature of the data center industry. The Company is open to revising and refining its modeling approach if future developments warrant such adjustments, but only after additional information on the data center industry becomes available. Thus, the Company does not agree with reducing the reserve margin based on potential data center load patterns at this time. As stated by Witness Looney in the 2025 IRP direct hearings:

> [W]e're not going to bring forth a recommendation to lower the reserve margin on the speculation that a certain customer class that we expect to materialize over the next five or six years behaves in a way that makes that turn out to be okay . . . . [W]e're not going to take a risk on setting a reserve margin based on the customer behavior that we have not yet been able to fully implement in a statistically meaningful way.[31]

Q. PLEASE DESCRIBE STAFF'S CRITIQUE OF THE COMPANY'S USE OF FIFTY YEARS OF WEATHER DATA TO INFORM ITS RESERVE MARGIN STUDY.

A. Staff testified that it reviewed Southern Company weather data for the years used in the Company's Reserve Margin Study in this case and found only three years in the 1980s when the minimum temperature fell below five degrees. Staff argues that these years "had a disproportionately large impact on the resulting winter TRM produced by the SERVM analysis."[32] According to Staff, use of thirty years of data, as opposed to fifty, would result in a more reasonable TRM.

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S CONCERN?

A. While the Company is not recommending a reserve margin that ensures it can serve all load during all potential extreme temperatures, there is no reason to ignore such

[31] Direct Hearing, Tr. Vol. 1 at 410:6–20.
[32] Newsome Panel at 33:13–14.

weather data in analyzing risks that the Company might encounter. Indeed, Staff witnesses admit that they are not suggesting that low temperatures from previous timeframes will never happen again.[33] Therefore, including this information in the Company's analysis plays an important role and such data should not be ignored. The Company's use of 50 years of data provides a more robust view of the potential weather extremes the system may face.

Additionally, it is reasonable to expect that in a Reserve Margin Study, a small subset of weather years will have a significant impact on the results. In fact, given the inclusion of 50 years of weather data and a 1:10 LOLE threshold, approximately five weather years should dictate the required level of reserves. In the Company's Reserve Margin Study, this happens to correlate with years in which temperatures fall below 10 degrees Fahrenheit. Accordingly, excluding such weather years in the analysis simply shifts the reliability risk for customers to higher temperatures.

IV. SCENARIO DESIGN, EXPANSION PLANNING, AND RESOURCE MIX STUDY

Q. WHY DOES THE COMPANY PERFORM EXPANSION PLANNING MODELING?

A. The Company's expansion planning analysis identifies the economically optimal mix of resources that reliably meet future customer capacity and energy needs across several plausible planning scenarios. The expansion plans indicate which types of resources provide value to customers. The expansion plans also provide guidance as to the amount of resources to be sought in renewable RFPs. Importantly, the expansion plans are combined with the existing fleet of resources as inputs into more detailed production cost modeling, which produces projected energy costs over the planning horizon. These projected energy costs are used in the Company's resource evaluations, including RFP evaluations, unit retirement

[33] *Id.* at 36:15–18.

studies, unit upgrade analyses, and demand side and program evaluations. Significantly, these models need to be realistic so that avoided cost signals are representative and provide a firm basis for analysis.

Q. ARE THE RESULTS OF ITS EXPANSION PLANNING MODELING CONSIDERED A FORMAL DECISION ON RESOURCE PLANNING?

A. No. As this panel has stated previously, the Company's generic expansion plans do not represent a resource planning decision by Georgia Power and are not commitments for resources. Instead, the expansion plans are indicative of what may be an optimal mix of resources within various future scenarios. While expansion planning is an important step in the decision-making process, it does not itself represent a formal plan or decision. In fact, the Company is required to procure supply side resources through an RFP process.[34] In short, these results are not commitments on the Company's part, and they do not drive the Company's specific resource actions.

A. Build Limits

Q. WHAT DO VARIOUS INTERVENORS RECOMMEND REGARDING THE COMPANY'S BUILD LIMITS IN ITS MODELING?

A. GCVEF Witness Roumpani recommends a justification for annual build limits and recommends exploring conditions under which the limits could be relaxed, particularly for renewable energy and storage resources.

GIPL Witness Hotaling expresses concerns about the Company's "restrictive build limits on solar" and recommends that Georgia Power present data without annual build limits applied to new solar resources.[35]

[34] Commission Rule 515-3-4-.04(3)(b)(2).
[35] Hotaling at 46:1–8.

Sierra Club/SACE/NRDC Witness Stenclik similarly recommends removing annual build limits on solar, wind, and storage in at least one unconstrained scenario to assess least-cost outcomes. He further recommends that the Company be required to justify how its build limits were developed and explain any changes to these build limits.

Finally, SREA Witness Palomino alleges that the IRP does not discuss the drivers for the Company's annual build limits and fails to elaborate on the reasons for wind and solar limits. Witness Palomino argues that when built capacity reaches the annual limit, "it suggests that the system has a greater appetite, and therefore economic incentive, to build wind and solar capacity than is permitted by Georgia Power's adopted constraints."[36]

Q. WHAT IS THE SIGNIFICANCE OF THE COMPANY'S BUILD LIMITS IN ITS EXPANSION PLANNING MODELING?

A. The build limits on generic resources are an important part of the Company's expansion planning process. As previously noted, expansion plans are combined with the existing fleet of resources as inputs into more detailed production cost modeling to produce projected energy costs over the planning horizon. These projected energy costs are then used in the Company's resource evaluations, including RFP evaluations, unit retirement studies, unit upgrade analyses, and demand side and program evaluations. Because these cases are used to evaluate and make subsequent resource decisions, it is important for the Company to assume practical limits, based on the Company's prior experience and knowledge, for all resources in its mix analysis.

[36] Direct Testimony of Alejandro Palomino on Behalf of Southern Renewable Energy Association, Docket No. 56002 (May 2, 2025) ("SREA Palomino") at 16:1–3.

Q. SOME INTERVENORS, LIKE SIERRA CLUB/SACE/NRDC, SUGGEST THAT PLANNING MODEL ASSUMPTIONS SHOULD BE RELAXED WHEN RESOURCE LIMITS ARE REACHED EVERY YEAR. IS THIS APPROPRIATE?

A. No. Intervenors argue that if the Company's AURORA model were unconstrained by build limits, it might seek to build more solar, wind, or other renewable resources than what the Company's build limits allow. However, higher amounts of resources may not always be practical to build, and the Company's build limits help ensure the model is performing its analysis within realistic parameters and providing appropriate projections of avoided energy costs.

In contrast, Sierra Club/SACE/NRDC Witness Stenclik testified that modeling exercises do not need to be realistic.[37] This is a flawed conclusion given that the Company uses its modeling results to inform and evaluate decisions in other contexts. Witness Stenclik acknowledged that actual resource planning decisions are up to the Commission and Company,[38] and therefore, it is crucial for the Company and the Commission to base decisions on realistic models.

Q. IS IT A COMMON INDUSTRY PRACTICE TO INCORPORATE BUILD LIMITS IN EXPANSION MODELING?

A. Yes. Most electric utilities include build limit assumptions in their expansion plans as part of their Integrated Resource Plans. For example, both Duke Energy Carolinas and Dominion Energy in Virginia have included such limits in their IRPs.[39]

[37] Tr. 158 (Intervenor Hearing Day 3).
[38] *Id.*
[39] *See Carolinas Resource Plan Meeting 3*, Duke Energy Carolinas, Docket No. E-100, Sub 204 (May 22, 2025) at 40, https://www.duke-energy.com/-/media/pdfs/our-company/irp-carolinas/carolinas-irp-mtg-3-slides-may-2025.pdf?rev=464e4daab1214b2b9aabfff0e191eea9 (last visited June 6, 2025); *2024 Integrated Resource Plan*, Va. Elec. and Power Co., Case No. PUR-2024-00184 (Oct. 15, 2024), at 55, https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/company/irp/2024-irp-w_o-appendices.pdf?rev=c03a36c512024003ae9606a6b6a239f3 (last visited June 6, 2025).

B. Integrated Modeling

Q. WHAT DOES STAFF PROPOSE REGARDING THE COMPANY'S USE OF INTEGRATED MODELING FOR THE RESOURCE MIX STUDY?

A. The witness panel of Newsome, Hayet, Sandonato, and Wellborn testified that "[a]lthough an economic analysis was performed in each of [the six different studies performed by the Company], the studies were not integrated."[40] Staff noted that "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."[41] Staff further testified that it performed an integrated analysis that concurrently evaluated a host of resource decisions, options, and retirements.[42]

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S CRITIQUE?

A. Staff's recommendation of an integrated analysis is not practical from the Company's perspective. As acknowledged by Staff Witnesses Newsome, Hayet, Sandonato, and Wellborn during the Staff and Intervenor hearing, to be able to run an integrated model, all inputs must be ready in order to run that integrated model.[43] Thus, while Staff's underlying reasoning may be factually accurate, Staff has the benefit of receiving a completed integrated resource plan with all of the Company's inputs already available to them. In comparison, when the Company develops its IRP for filing, the Company does not have the same benefit of having complete inputs available all at the same time. Rather, many of the Company's studies supporting the IRP are conducted sequentially and rely on the outputs of a completed study as an input for another study. For example, the Company did not have (and in fact, could not have) the results of the All-Source RFP at the time that

[40] Newsome Panel at 88:23–24; *see also* Tr. 226 (Intervenor Hearing Day 1) (acknowledging that Company studies are not run as an integrated model).
[41] Newsome Panel at 88:30–89:2.
[42] *See id.* at 89:3–14.
[43] Tr. 226–27 (Intervenor Hearing Day 1).

it performed its Resource Mix Study, yet Staff nevertheless recommends that the Company perform a complete analysis with missing information.

Q. DESPITE RUNNING AN INTEGRATED ANALYSIS, DID THE STAFF AND COMPANY REACH SIMILAR CONCLUSIONS RELATED TO THE COMPANY REQUESTS IN THIS IRP?

A. Yes. The Witness panel of Newsome, Hayet, Sandonato, and Wellborn testified that "for the incremental resource additions, we have concluded the same" as the Company.[44]

C. Costs of Combined Cycle and Combustion Turbines

Q. PLEASE SUMMARIZE STAFF'S AND INTERVENORS' CRITICISMS OF THE COMPANY'S CC AND CT COSTS ASSUMED IN THE IRP.

A. Staff and some Intervenors testified that the Company's CC and CT costs used in the Resource Mix Study were lower than current market expectations. They base their testimony on comparisons of the Company's costs to other electric utilities costs for the same technologies being deployed on their systems.

Q. HAS THE COMPANY ACKNOWLEDGED INCREASES IN COMBINED CYCLE AND COMBUSTION TURBINE COSTS SINCE THE RESOURCE MIX STUDY WAS FILED?

A. Yes. Witness Hubbert acknowledged this during the Company's direct hearings:

> So the vintage of the data that supported the mix study, because it had to be done to support the filing, was around August, maybe September time frame. So since that time frame, we are aware that costs have increased because of the global demand for combustion turbines, [and] combined cycles. But we did not update the mix study, including higher costs. However, we have used a higher cost when making offers to customers – large load customers and

[44] Tr. 228 (Intervenor Hearing Day 1).

incorporating it into those analyses, but we didn't redo the entire mix study with a higher cost for a single technology or two technologies.[45]

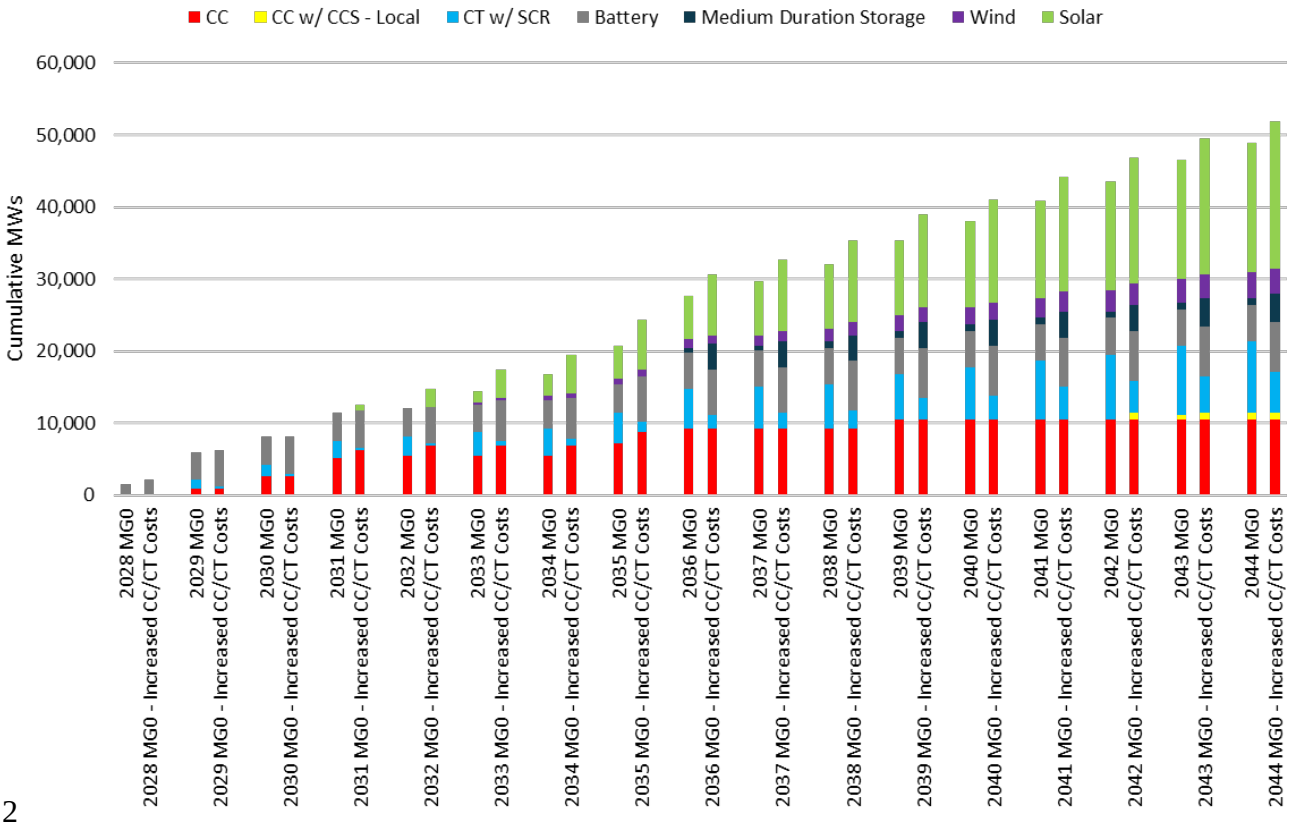
Q. DID THE COMPANY PERFORM ANY ANALYSIS USING INCREASED COSTS FOR CCS AND CTS?

A. Yes. The Company conducted a sensitivity with increased CC and CT costs on the MG0 and 111-MG0 scenarios. The increased costs are consistent with the costs included in Staff's and Intervenors' testimony.

The Company performed its full resource mix analysis with these increased costs in the MG0 scenario. Through 2035, the AURORA model selected more CC, battery energy storage, and solar and selected less CT. Through 2044, the model selected the same amount of CC, more battery energy storage and solar, and less CT. See Figure 5 below for additional details.

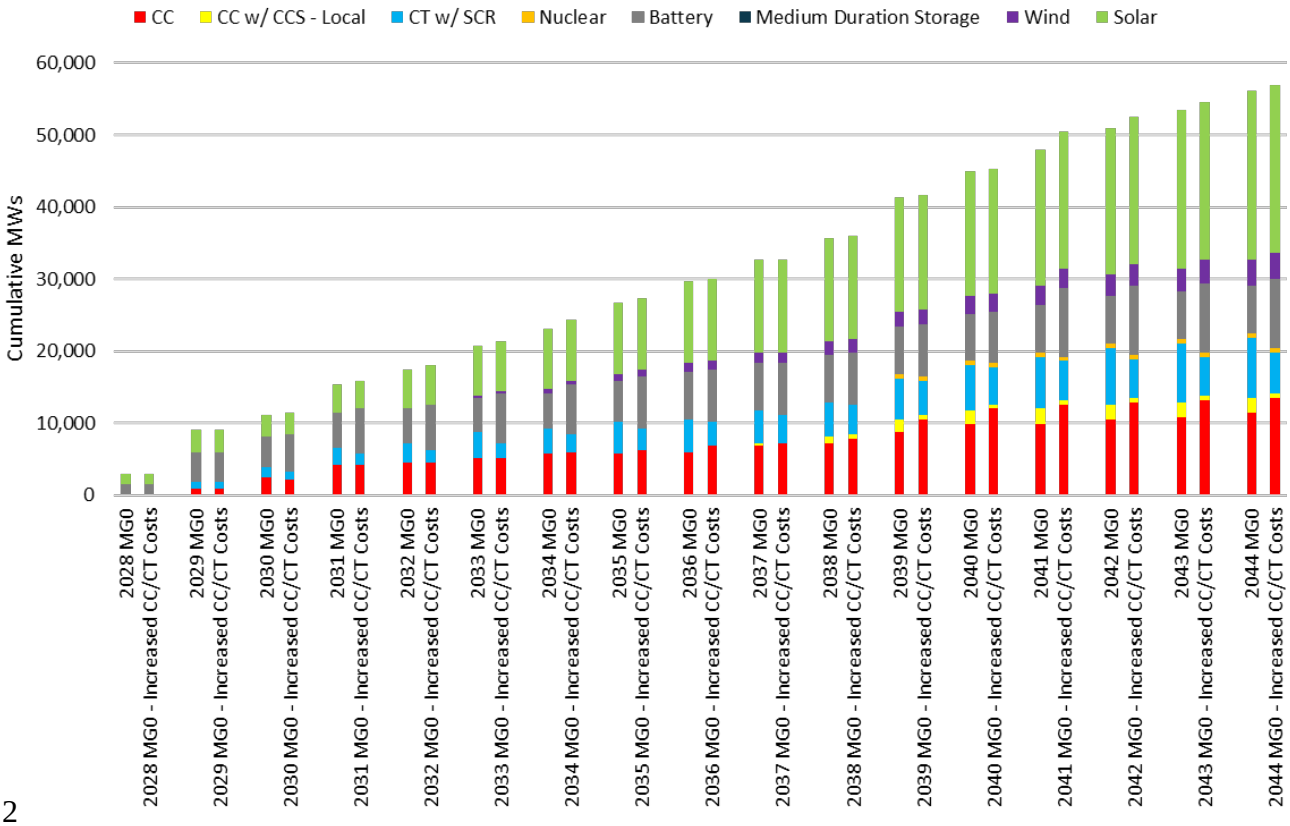
[45] Direct Hearing Tr. Vol. 1, at 513:16–514:2.

Figure 5: MG0 as Filed vs. MG0 with Increased CC/CT Costs Sensitivity



The Company performed the same analysis in the 111-MG0 scenario. Through 2035 and 2044, the AURORA model selected more CC and battery energy storage and less CT. Overall, while the selections do change when modeling higher CC and CT costs, the results still indicate that the economically optimal mix of resources include CC, CT, battery energy storage, wind, and solar. See Figure 6 below for additional details.

Figure 6: 111-MG0 as Filed vs. 111-MG0 with Increased CC/CT Costs Sensitivity



Q. WILL THE COMPANY UPDATE ITS COST ASSUMPTIONS FOR THESE TECHNOLOGIES?

A. Yes. As part of the annual IRP process, the Company will continue its normal process of gathering the best available information for both cost and performance for all generation technologies to be considered in the Company's resource plans. In addition, the Company will use actual information for specific resources to inform cost and performance for generation technologies. For example, the 2029-2031 All Source RFP information referenced by Staff will be considered when updating costs for all technologies assumed in its annual planning processes.

V. RENEWABLE INTEGRATION STUDY

Q. WHAT CONCERN DOES STAFF RAISE REGARDING THE RENEWABLE INTEGRATION STUDY'S USE IN THE COMPANY'S PLANNING PROCESS?

A. Staff Witnesses Barber, Kaduk, and Bower state in part that the Company's Renewable Integration Study is "essentially a theoretical exercise, and the model methodology is not designed to quantify a specific cost actually incurred on Georgia Power's system."[46] Staff further alleges that the Company "has not adequately demonstrated that it is appropriate for use in the Company's planning process."[47]

Q. WHY DOES THE COMPANY CONDUCT A RENEWABLE INTEGRATION STUDY AND WHY DOES IT APPLY IT IN RENEWABLE ENERGY PROCUREMENTS?

A. As intermittent resources are added to the system, the integration costs identified by the Company's Renewable Integration Study represent the costs associated with any increase in operating reserves that is necessary to ensure the Southern Company System maintains its ability to meet reliability standard requirements. To account for the additional cost of these operation reserves to respond to variation in generation levels, the study identifies a value that is allocated as a cost to intermittent resources or a benefit to resources, such as BESS, which address the volatility by serving as operating reserves. Therefore, the Renewable Integration Study is more than just a mere theoretical exercise; in fact, the Renewable Integration Study has very real implications to the Company's resource evaluations and decisions.

[46] Direct Testimony of Jamie Barber, John Kaduk, and Jeffrey D. Bower, Docket Nos. 56002 and 56003 (May 5, 2025), at 14:13–14.
[47] *Id.* at 14:14–18.

VI. UNIT UPGRADES

A. Nuclear Unit Upgrades

Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATION REGARDING THE COMPANY'S PROPOSED NUCLEAR UNIT UPGRADES.

A. Staff testified that the Company's proposed nuclear unit upgrades are economic but recommended that the Commission approve the upgrades at Plant Vogtle Units 1-2 first, then delay the upgrades at Plant Hatch Units 1-2 until two years after the Vogtle upgrades are completed.[48] In support of this recommendation, Staff testified that the delay will "allow the Company to incorporate its experience with [the] Vogtle 1-2 upgrade in its execution of the Hatch 1-2 upgrade."[49]

Q. WILL THE COMPANY'S EXPERIENCE FROM VOGTLE UNITS 1-2 INFORM THE COMPANY'S UPGRADES AT PLANT HATCH?

A. No. While Plants Vogtle and Hatch are both nuclear units, their similarities generally end there. Among other differences, Plant Vogtle uses pressurized water reactors, while Plant Hatch uses boiling water reactors; both units also differ in their containment types. In essence, while both units are nuclear units, they are distinctly different nuclear units.

Staff argues that the upgrade projects are mostly on the secondary side of the nuclear units—i.e., the thermal side—and that therefore, any difference in the nuclear technology does not matter.[50] However, the Company also has vast experience with the thermal side of power plants, both at these two nuclear plants as well as at every other plant in its fleet with a thermal component. Therefore, the

[48] Newsome Panel at 82:11–16.
[49] *Id.* at 82:16–17.
[50] Tr. 220–21 (Intervenor Hearing Day 1).

value of any lessons learned or experience from the Vogtle units is outweighed by the economic costs of Staff's proposed delay.

Furthermore, the Company has performed three prior upgrades at Plant Hatch and two prior upgrades at Plant Vogtle. Accordingly, the Company already has experience at both units to support the timely and efficient upgrades at both plants. Therefore, Staff's suggestion that the Company can incorporate lessons learned from its experience from one nuclear unit to another is not as practical as the witnesses suggest, and certainly not valuable enough to delay the projects and delay and reduce benefits to customers.

Q. ASIDE FROM EXPERIENCE OR LESSONS LEARNED, IS IT ECONOMICAL TO DELAY THE UPGRADES AT EITHER NUCLEAR UNIT?

A. No. Staff notes that these projects are "capital intensive, will require significant lead time . . . , and will take a relatively long time to break even."[51] However, Staff acknowledged that these projects were in fact economic,[52] and the capital costs associated with these projects would still be lower than new nuclear. Delaying these projects reduces their economic value and reduces the remaining asset lives over which to enjoy the benefits. Specifically, Staff's proposed schedule would delay the capacity benefit from Hatch from 2029 to 2032 at the earliest, which immediately reduces the economics of the projects. Delays can also increase costs associated with general inflation, extended AFUDC, labor retention, preventative maintenance of units, and tax credit applicability. Other utilities around the nation are pursing similar nuclear upgrades—this creates increased competition for labor, delays potential procurements, and requires greater storage costs as the Company must store long-lead items more than necessary.

[51] Newsome Panel at 82:1–13.
[52] *Id.* at 82:11.

Notably, to support their conclusion, Staff only modeled a two-year delay for these upgrades; Staff did not model and did not include in its testimony any evidence that their proposed delay of these upgrades would maintain the economic value provided by the performance of the upgrades as proposed by the Company. Any assumption that the delay of nuclear upgrades would be economic is unsubstantiated. These nuclear upgrade projects represent an opportunity to obtain additional carbon free, nuclear generation that would not otherwise present itself for many years.

B. Hydro Unit Upgrades

Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATION REGARDING THE COMPANY'S PROPOSED HYDRO UNIT UPGRADES.

A. Staff recommends that the Company's proposed hydro modernization request be denied, but nevertheless supports the expansion of the Company's proposed hydro modernization program generally and recommends the Commission approve up to $100 million to support preliminary investigation and engineering studies through 2027.[53] Staff argues that the results from these investigations and studies would allow the Commission to better determine how to proceed with hydro modernization.[54]

Q. CAN THE HYDRO MODERNIZATION PROGRAM CONTINUE UNTIL THE 2028 IRP UNDER STAFF'S RECOMMENDATION?

A. No. As proposed by Staff, the preliminary investigation and engineering studies would precede equipment procurement, which is impractical for how hydro units are engineered. In preliminary meetings with Staff, the Company explained that, due to the unit-specific nature of hydro plants, hydro turbines are typically the first step in the engineering process, and engineers design the custom replacement based

[53] *Id.* at 85:18; 87:1–12.
[54] *Id.* at 87:1–12.

on the turbine that is procured. Unlike other generation resources, any preliminary engineering performed before the procurement of equipment would not be usable, and the same work would likely need to be repeated after the equipment is actually procured. In other words, Staff's proposal to front-end investigation and engineering studies would lead to increased spending on engineering and design costs.

Q. ARE ALL CURRENTLY APPROVED HYDRO MODERNIZATION PROJECTS EXPECTED TO BE COMPLETED BEFORE THE 2028 IRP?

A. Yes. Plant Tugalo Unit 4 was completed in April 2025, and the Company currently expects to complete 10 of the 14 remaining approved units by the end of 2026 and the last four approved units in 2027. Therefore, the currently approved projects are all expected to be completed before the 2028 IRP.[55] Delaying any new projects will create a gap in the modernization program, as the program will cease entirely before being approved again and modernization of additional units will not be completed for potentially three to six years beyond the schedule included in the Company's request.[56] This delay will lead to inefficiencies, increase costs, and likely result in a loss of an assembled and skilled labor workforce. Accordingly, the Company must commence additional units in 2026 in order to optimize the hydro modernization program for the benefit of customers.

Q. IS THE COMPANY'S HYDRO MODERNIZATION REQUEST IN THIS PROCEEDING THE LEAST-COST PLAN TO CUSTOMERS?

A. Yes. By building on the momentum of the current hydro modernization program, the approval of all additional projects to be completed as soon as possible is the

[55] The Company's proposed schedule, if approved, would actually be ahead of the schedule proposed in the 2022 IRP, which expected one unit at Plant Oliver to begin modernization work in 2028.
[56] *See* 2025 IRP, Technical Appendix Vol. 1, "2025 IRP Hydro Modernization" at 10.

lowest cost option for customers. This path ensures that the Company and customers avoid increased costs caused by delays and decreased efficiencies.

Q. DID THE COMPANY'S COST-BENEFIT ANALYSIS FIND HYDRO MODERNIZATION TO BE ECONOMIC FOR CUSTOMERS?

A. Yes. For all plants except Morgan Falls, the Company's plan found hydro modernization to be economic for customers. As this panel previously testified, the high level of qualitative benefits provided by Morgan Falls support the continued investment and modernization of Morgan Falls notwithstanding the less favorable economics.[57]

VII. TRANSMISSION PLANNING

Q. PLEASE BRIEFLY REINTRODUCE THE TRANSMISSION COMPONENTS OF THE 2025 IRP.

A. The 2025 IRP includes (i) the 2024 Georgia Integrated Transmission System ("ITS") Ten-Year Plan, which incorporates generation and load growth updates for Georgia Power, Georgia Transmission Corporation ("GTC"), the Municipal Electric Authority of Georgia ("MEAG Power"), and Dalton Utilities (collectively, the "ITS Participants"), (ii) updates on strategic transmission projects since the 2022 IRP to address South to North transmission constraints, and (iii) additional considerations for evolving System needs beyond the traditional ten-year transmission planning window.

[57] *See* Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle, Docket Nos. 56002 & 56003 (Feb. 28, 2025) ("Main Panel Direct Testimony") at 35:3–20.

Q. PLEASE RESPOND TO THE RECOMMENDATION OF SEVERAL PARTIES THAT GEORGIA POWER SHOULD ADOPT A MULTI-VALUE, PROACTIVE TRANSMISSION PLANNING PROCESS.

A. It is important to first highlight that, as explained in response to similar recommendations in the 2023 IRP Update, Georgia Power's existing planning framework and process already incorporates most of the parties' suggestions. The Company's IRP process carefully and intentionally considers the balance between transmission investment and generation deployment. Through the existing robust IRP and RFP processes, Georgia Power can accurately evaluate transmission and generation decisions during the resource planning and procurement processes. Transmission represents one component in this planning process; however, long-term firm commitments by third parties under a FERC-jurisdictional Open Access Transmission Tariff ("OATT") also drive transmission planning evaluations and decisions.

As discussed more fully below, the Company engages, coordinates, and plans locally with ITS Participants, neighboring systems, and utilities on transmission planning issues. The Southeast Regional Transmission Planning ("SERTP") transmission planning process also coordinates across the southeast to seek input, identify and review system improvements using least-cost and reliable solutions from all reasonably available alternatives, similar to those recommended by the parties.

Further, Georgia Power is already prudently considering and developing the planning and process improvements that Staff and Intervenor parties recommend as part of evolving transmission planning processes and consistent with requirements of FERC Order 1920.

Q. PLEASE DESCRIBE HOW REGIONAL COLLABORATION AND COORDINATION INFORM THE TRANSMISSION PLANNING PROCESS IN GEORGIA.

A. Sections D1 and E1 of Technical Appendix Volume 3 outline the Georgia ITS and SERTP planning processes. Both processes demonstrate tight coordination in transmission planning efforts among the ITS Participants in Georgia and with neighboring utilities.

Staff and Intervenors offer recommendations that seemingly disregard the integrated nature of the transmission system in Georgia, whereby Georgia Power jointly plans and operates the networked transmission system with all ITS Participants. To that end, the Ten-Year Plan incorporates generation and load growth updates for Georgia Power and all other ITS Participants, including changes since the 2022 IRP and 2023 IRP Update. This collaborative planning approach fosters natural checks and balances within transmission system planning and the development of future transmission project solutions.

Q. DOES GEORGIA POWER COORDINATE AND PARTICIPATE IN REGIONAL PLANNING WITH NEIGHBORING SYSTEMS AND UTILITIES?

A. Yes. Southern Company and Georgia Power work with neighboring utilities directly and through SERTP to ensure a robust, cost-effective transmission plan that meets customer needs and ensures reliability. The SERTP process is a collaboration of nine transmission planning entities in an 11-state area that coordinates regional transmission planning and provides an open and transparent forum for regional planning and coordination, stakeholder input, and stakeholder engagement.[58] The SERTP planning process consists of a bottom-up planning

[58] SERTP transmission owners and providers include Duke Energy, Dalton Utilities, Georgia Transmission Corporation, Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas & Electric Company and Kentucky Utilities Company, Associated Electric Cooperative Inc., and TVA.

model that combines the state-level IRP and expansion plans of each sponsor, ensuring that drivers of future needs are incorporated and done in accordance with such state oversight. Importantly, SERTP is made up of vertically integrated utilities who each have an obligation to provide reliable, cost-effective energy to customers.

In addition to SERTP, examples of planning, communication, and coordination with neighboring utilities and systems include biannual coordination meetings between Southern Company and its interconnected neighboring utilities, the SERC Reliability Corporation Long-Term Working Group ("LTWG"), and from time-to-time the Eastern Interconnection Planning Collaborative ("EIPC"). In these venues, studies may be performed as needed to determine impacts resulting from changes in transmission topology on both sides of a given interface.

Q. DOES GEORGIA POWER COORDINATE TRANSMISSION PLANNING ACROSS THE SOUTHERN COMPANY SYSTEM?

A. Yes. Georgia Power jointly plans with Southern Company, Alabama Power Company, and Mississippi Power Company at the system level. The Ten-Year Plan included in the 2025 IRP represents one component of that joint system planning process.

Q. **IS THERE A SHARING MECHANISM FOR ALLOCATING COSTS TO THE OPERATING COMPANIES?**

A. Yes. Facility costs are allocated to operating companies through the Transmission Facility Cost Allocation Tariff on file with FERC.[59]

[59] *See, e.g.*, Alabama Power Company - Cost Based Rate Tariffs, Tariff Volume No. 13, Transmission Facility Cost Allocation Tariff (5.0.0), https://etariff.ferc.gov/TariffBrowser.aspx?tid=1931 (incorporated by reference into Georgia Power's tariff record on July 3, 2018, *see* "Georgia Power Company submits tariff filing per 35.13(a)(2)(iii)," Docket ER18-1939 (July 3, 2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180703-5057&optimized=false (last accessed June 8, 2025)). .

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF FERC ORDER 1920 AND DISCUSS HOW IT WILL IMPACT GEORGIA POWER'S LOCAL, REGIONAL, AND INTERREGIONAL TRANSMISSION PLANNING PROCESSES.

A. FERC Order 1920[60] directly includes and requires many of the planning and process improvements that parties recommend in this proceeding. At a high level, together, FERC Orders 1920, 1920-A, and 1920-B mandate a Long-Term Regional Transmission Planning ("LTRTP") process using a 20-year planning horizon with multiple transmission needs scenarios. FERC Order 1920 also includes specific requirements addressing regional and local transmission planning efforts and consideration of Grid-Enhancing Technologies ("GETs").

Q. DOES FERC ORDER 1920 ADDRESS STAKEHOLDER ENGAGEMENT AND PROCESSES?

A. Yes. FERC Order 1920 requires three publicly noticed stakeholder meetings per regional transmission planning cycle to address local transmission planning assumptions, transmission needs, and solutions.

Q. PLEASE DISCUSS THE TIMELINE FOR DEVELOPING AND IMPLEMENTING A PLAN FOR COMPLYING WITH FERC ORDER 1920.

A. Georgia Power is currently developing a comprehensive compliance and execution plan for addressing the reforms and improvements required by FERC Order 1920.

SERTP Sponsors, together with SCRTP sponsors, are also developing their compliance plan consistent with the directives in FERC Order 1920, 1920-A, and 1920-B. This compliance plan will address each requirement outlined in FERC Order 1920 and subsequent Orders 1920-A and 1920-B. Regional requirements

[60] *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation*, 187 FERC ¶ 61,068 (2024) ("Order 1920").

compliance plans are due by June 12, 2026, and interregional compliance plans are due by August 12, 2026. Thereafter, Georgia Power will begin compliance with its regional and interregional plans by June 12 and August 12, 2028, respectively.

Q. GIVEN THE EXTENSIVE COLLABORATION, LONG-TERM TRANSMISSION PLANNING EFFORTS, AND PLANNED ENHANCEMENTS ASSOCIATED WITH FERC ORDER 1920 COMPLIANCE, IS ADDITIONAL STAKEHOLDER INVOLVEMENT NECESSARY?

A. No. As described above, the Company is actively involved in robust and collaborative planning processes that facilitate stakeholder engagement and feedback. Informal and organic engagement opportunities on transmission planning-related topics will likely arise in the future.

Q. PLEASE RESPOND TO STAFF WITNESS GOGGIN'S RECOMMENDATION THAT GEORGIA POWER SHOULD PLAN FOR HIGHER VOLTAGE AND HIGHER CAPACITY TRANSMISSION SOLUTIONS.

A. The Company disagrees that higher voltage, double-circuit transmission "is significantly more cost effective" than other transmission planning approaches.[61] Simply proposing to plan for more expensive and potentially unnecessary solutions contradicts how transmission planning is coordinated with generation resource planning in Georgia. In deregulated markets, transmission owners build large transmission lines across states hoping that they have sited the infrastructure where independent power producers will seek to interconnect. In Georgia, however, without a clearly justified need to increase transmission capacity further, this

[61] Direct Testimony of Michael S. Goggin, Docket Nos. 56002 & 56003 (May 5, 2025) ("Goggin") at 24:8.

approach would likely result in expensive infrastructure investments with no guarantee to alleviate known or anticipated transmission constraints.

Georgia Power is already implementing the type of forward-looking, high-capacity transmission planning that Staff recommends. Georgia Power builds transmission as needed to deliver power from facilities that have been sited, financed, and have initiated the process of interconnecting to the System. Georgia Power's integrated approach ensures interconnections actually occur and minimizes transmission investments based upon speculation. As mentioned above and in Technical Appendix Volume 3, Georgia Power jointly plans and operates the networked transmission system with the ITS Participants who are jointly focused on developing transmission plans that prioritize both reliability and affordability in their planning processes.

Georgia Power's transmission planning process already incorporates higher voltage and higher capacity solutions where they are most effective and economical. Through the ITS, the Company evaluates 500kV, 230kV, and 115kV options in a tiered, system-wide approach that prioritizes robust, long-term solutions. For example, projects like the Butler–Thomaston 230kV conversion and the Farley–Tazewell 500kV expansion represent examples of high-capacity upgrades that relieve thermal constraints and enhance transfer capability across regions. Importantly, these projects are selected not in isolation, but as part of a coordinated statewide plan that aligns with NERC reliability standards and supports Georgia's evolving generation mix and load growth.

Q. STAFF WITNESS GOGGIN ALSO RECOMMENDS THAT GEORGIA POWER EXPAND TIES TO NEIGHBORING UTILITIES TO IMPROVE RELIABILITY. PLEASE RESPOND.

A. The Company examines this option in the transmission planning process and has expanded ties to neighboring utilities and systems when appropriate. For example, in developing the Ten-Year Plan, Georgia Power coordinates with utilities through

the SERTP process. In addition, Georgia Power works directly with interconnected utilities to perform joint evaluations, which could result in identifying transmission facilities that could better meet the needs identified in respective plans. The Company plans for firm and future firm obligations, including transmission reliability margin and capacity benefit margin. Furthermore, as described above, Georgia Power will continue considering and evaluating regional and transmission planning including the costs and benefits associated with potential solutions and consistent with the existing FERC regional planning requirements and processes and directives outlined in FERC Order 1920.

Witness Goggin did not evaluate or consider the costs or benefits associated with expanding ties to neighboring utilities for reliability purposes. In fact, Witness Goggin provided no supporting analysis or evaluation supporting this recommendation as he recommends that Georgia Power perform the required diligence, which the Company already considers through existing planning processes.

In addition to potential cost barriers, relying on expanded ties with neighboring systems presents several potential risks. For example, simply building interfaces between balancing authorities does not guarantee that the neighboring utility can or will deliver power to the corresponding ties in times of need. If a neighboring system not controlled by Georgia Power fails to deliver power during capacity constrained periods, Georgia Power would still be held responsible. Other potential risks include delayed resource availability, curtailment due to transmission constraints and/or capacity emergencies in neighboring areas, and transmission system stability issues.

Georgia Power is obligated to ensure that energy and generation capacity requirements are met in a reliable, cost-effective manner. Decisions on the value of specific transmission improvements are complex and must consider all relevant

factors. Simply put, expanded ties cannot alone replace the value of sufficient generation capacity and energy located in Georgia.

Q. STAFF SUGGESTS THAT THE COMPANY SHOULD EXAMINE THE OVERBUILDING RISKS ASSOCIATED WITH AREA MAX SCENARIOS. DOES THE COMPANY AGREE?

A. No. Staff incorrectly concludes that Georgia Power employs a process that reflects extreme, infrequent system conditions that may never occur in practice. Georgia Power employs a reasonable approach that appropriately focuses on targeted generation pockets to ensure generation capacity is not constrained by transmission in a given area. Importantly, the Company maximizes the value to customers by mitigating physical delivery risks, ensuring the ability to economically dispatch and reducing curtailment risks for firm and future firm generation resources, consistent with the Company's transmission planning principles.

Q. SHOULD THE COMMISSION REQUIRE THAT GEORGIA POWER ADOPT A COMPREHENSIVE PROCESS FOR EVALUATING GRID-ENHANCING TECHNOLOGIES AND NON-WIRES ALTERNATIVES AS RECOMMENDED BY STAFF?

A. No such requirement is necessary. The Company continually explores all options for meeting customer needs including innovative transmission solutions using GETs, where these technologies are safe, reliable, and economical. To that end, Georgia Power has and will continue exploring options for further implementing GETs and non-wires alternatives ("NWA") solutions. And, as noted by Staff, the Company has developed a diverse solution portfolio that leverages these alternatives for the benefit of customers. Staff Witnesses Smith and Kannan confirmed that the Company has effectively implemented GETs across the transmission system, including deployment of advanced conductors, dynamic line

ratings ("DLR"), and power flow controllers.[62] Georgia Power's efforts at developing and deploying GETs has also been acknowledged by the Department of Energy and industry reports cataloguing utility projects that are advancing the priorities necessary for advanced transmission liftoff and deployment at scale.[63]

Further, the 2023 IRP Update Stipulation, approved by this Commission, required that Georgia Power continue investing in GETs solutions. Specifically, Paragraph 20 of the 2023 IRP Update Stipulation required that Georgia Power "continue to investigate opportunities to use distributed energy resources and grid-enhancing technologies, to reduce or defer the need for transmission upgrades needed to accommodate future load growth or proposed generation additions."[64] Through the 2025 IRP process, Georgia Power has complied with the directive outlined in 2023 IRP Update Stipulation and will continue to evaluate innovative solutions – including GETs – in the transmission planning process.

Q. DOES GEORGIA POWER APPROPRIATELY CONSIDER ADVANCED CONDUCTORS IN ITS TRANSMISSION PLANNING AND DESIGN PROCESS INCLUDING 500KV CONSIDERATIONS?

A. Yes. The Company actively deploys advanced conductors as appropriate and identifies these opportunities in its transmission planning process. As included in Technical Appendix Volume 3, 87 projects have already identified the use of advanced conductors as part of the solution. Georgia Power also utilizes other innovative solutions in its transmission planning and operations processes as described in Section 11 of the Main IRP document and as demonstrated in Technical Appendix Volume 3.

[62] Direct Testimony of Douglas A. Smith and Sasikumar Kannan, Docket Nos. 56002 and 56003 (May 5, 2025) at 20.
[63] *See* GPC Exhibit 16, "December 2024 Deploy Dialogues Summary Report" at 20.
[64] *Order Adopting Stipulated Agreement*, Attachment A, Docket No. 55378 (Apr. 26, 2024) at ¶ 20.

As with the development of any transmission solution, the Company considers multiple factors in the evaluation process to identify potential solutions and selects the preferred solution in accordance with its transmission planning principles. Georgia Power does not currently use advanced conductors as 500kV solutions, however, as GIPL and Southface Witness Patel recommends, because using advanced conductors at this voltage level is not in the best interest of the reliability of the grid nor is it cost-effective for customers. Increasing the total energy capacity of 500kV transmission lines can create new contingency events that are significantly larger than those currently considered in transmission planning studies. If transmission-connected assets are added to the system that increase reliability exposure due to a new largest contingency, that can create further needs to build more transmission infrastructure to ensure the grid can reliably withstand larger contingency events consistent with NERC transmission planning standards. Additionally, creating higher current-carrying capacity on existing 500kV lines through the deployment of advanced conductors instead of increasing the operational voltage could lead to the inability to find terminal equipment with sufficiently high operating characteristics to safely and reliably carry the increased current, thereby limiting the ability to fully achieve the desired increased capacity of the transmission line.

Georgia Power continues to evaluate the use of innovative technologies such as advanced conductors for transmission projects and includes considerations such as those described to select the best solution for each situation. Further, the Company will continue examining all solutions to solve or improve reliability needs for the transmission grid and that are safe and cost-effective.

Q. WHY DID GEORGIA POWER NOT EVALUATE BATTERY STORAGE AS A TRANSMISSION SOLUTION FOR CONSTRAINTS IDENTIFIED IN THE 2025 IRP?

A. Battery storage as a transmission alternative is often impractical and uneconomic for several reasons. First, batteries require grid power for charging, which causes it to act like additional load thereby potentially exacerbating the very constraints that the additional resources and transmission solutions are intended to resolve. Second, batteries serving as transmission solutions cannot simultaneously count as both generation capacity and a transmission solution within the Southern Company System. There are numerous contingency events that could create a need for batteries to be deployed as either a generation or transmission solution, and if a battery is not dedicated to be available for its designated generation or transmission use case(s), there is no way to guarantee it will be available to respond as needed in an emergency event. For example, a battery would need to be available for every possible contingency combination that can cause the identified transmission line to overload. Third, a 4-hour battery is not a practical solution. For example, a tornado could create an unexpected outage during hot weather conditions that lasts for a week. For batteries to resolve the resulting transmission constraints, the grid would need enough available capacity to charge the battery system(s), they would need to be of significant size and discharge duration, and there may need to be multiple battery systems to cover the multiple contingencies across different locations identified in a transmission planning analysis. As a result, in this scenario, the overall cost and land requirements to support battery projects that can cover extended duration outages would be cost prohibitive. Finally, Georgia Power would need to run a total net present value of the battery systems versus wire solutions to contemplate the total life-cycle cost of the two alternatives.

If future BESS applications, configurations, and operations demonstrate that BESS can be deployed reliably and economically as transmission solutions, Georgia Power will continue to consider this technology as a solution. In parallel, the

Company is continuing to gain operational experience through the successful deployment of the Mossy Branch Battery Facility, the first transmission-connected BESS on the System, and ongoing 500 MW BESS deployments approved by the Commission in the 2023 IRP Update and any others that may come from ongoing or upcoming RFP solicitations.

Q. INTERVENORS RECOMMEND THAT GEORGIA POWER CONSIDER CURTAILABLE LOAD FOR DATA CENTERS IN THE TRANSMISSION PLANNING PROCESS. DOES THE COMPANY HAVE AN EXISTING PROCESS ADDRESSING THIS ISSUE?

A. Yes. As referenced in the direct testimony of the Customer Programs Panel, the Company has existing and proposed programs intended to enable load flexibility to provide system value. Already approved tariffs include DPEC, CL, DRC, DCO, and DCL. Using interruptible load to address transmission contingencies is subject to additional requirements. The proposed Large Customer Owned Resiliency ("LCOR") program is designed such that customer sited DERs could be leveraged for transmission use cases. As we previously testified at the Company's direct hearings in this docket, we have and will continue to inquire directly with large loads concerning their ability and desire to participate in such programs and their ability to designate all or part of their load as non-firm and curtailable.[65]

VIII. WHOLESALE-TO-RETAIL OFFER

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S WHOLESALE-TO-RETAIL OFFER?

A. Staff testified that the Company's wholesale-to-retail offer was a "close call," and if the Commission determines to take more capacity than what Staff is recommending, then the Scherer Unit 3 Wholesale Blocks 1–3 should be the first

[65] *See* Direct Hearing, Tr. Vol. 1, 726–28.

additional resources procured.[66] Moreover, Staff recommends the consideration of Block 4 only if the Company agreed to certain conditions.

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S ANALYSIS OF THE WHOLESALE-TO-RETAIL OFFER?

A. Staff only allowed Block 1 of the wholesale-to-retail offer to be selected in 2026, when there was no capacity need. If Staff had allowed Block 1 to be selected in 2026 and beyond, Staff's model would have selected this block.[67]

Q. WHAT RISK DOES THE WHOLESALE TO RETAIL OFFER PRESENT?

A The Company's proposed wholesale-to-retail offer presents very little risk, if any. The MW associated with this proposal is capacity that the Company can reliably deploy for retail use, comes with no construction risks, and requires no additional transmission projects. Staff's proposal to segment the acquisition and condition the fourth block on certain requirements should be considered in light of this lack of risk, and the Commission should consider acquiring all four blocks instead. This offer is an opportunity to maximize economic and reliable capacity from the extension of Plant Scherer Unit 3 to serve customers during a time of capacity and energy need.

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[66] Newsome Panel at 7:1–3.
[67] Tr. 229–230 (Intervenor Hearing Day 1).

EXHIBIT 1: FEBRUARY 2025 LOAD FORECAST

As described herein, Section 7.0 to the Company's Load and Energy Forecast found in Technical Appendix Volume 1 has been updated to account for the revised large load economic development pipeline and underlying assumptions, consistent with the February 2025 sensitivity results shared in hearing request response, HR-1-1.[1]

7.0 FORECAST ADJUSTMENTS FOR LARGE CUSTOMERS

The February 2025 Load Forecast continues to utilize the Load Realization Model developed for the 2023 IRP Update. This model uses a probabilistic approach to evaluate the range and likelihood of future potential outcomes of the load growth from new large-load customers. The results of this approach support the external adjustment applied to the commercial and industrial load and energy forecasts. This Section describes the methodology and assumptions behind the probabilistic approach that is used.

As in the 2023 IRP Update and the Budget 2025, the February 2025 Load Forecast includes an external adjustment to its baseline, organic forecast to account for the increased large load additions described herein. An external adjustment is needed for these loads since Georgia's unprecedented economic development growth would not otherwise be captured in the historical trends underlying the baseline forecast. Georgia Power has made external adjustments for large new customers in the past. For example, the Company adjusted its forecast in the 2016 and 2019 IRPs to account for the addition of the Elba Island Liquified Natural Gas facility, which represented a completely new industry to the state.

Notwithstanding prior large load external adjustments to the forecast, prior to 2023 IRP Update, the Company had never seen such a significant number of new large customer projects materialize in such a short period of time. As a result, Georgia Power developed a way to estimate the impacts of these projects on its system while also addressing the inherent uncertainties around whether

[1] The sensitivity provided by the Company in response to HR-1-1 was a draft sensitivity. The Company has provided the finalized sensitivity in this Exhibit 1. This resulted in a small change that captures the delay of commercial operations for two projects.

such projects will ultimately locate in Georgia, select Georgia Power as the electric service provider, and come online with the anticipated load. The probabilistic model Georgia Power developed to address these considerations, the Load Realization Model, is discussed in the section below.

7.1 MODEL OVERVIEW

7.1.1 Known Project Inputs

For each large load project the Company has evaluated and included in the February 2025 Load Forecast, the following information is provided:

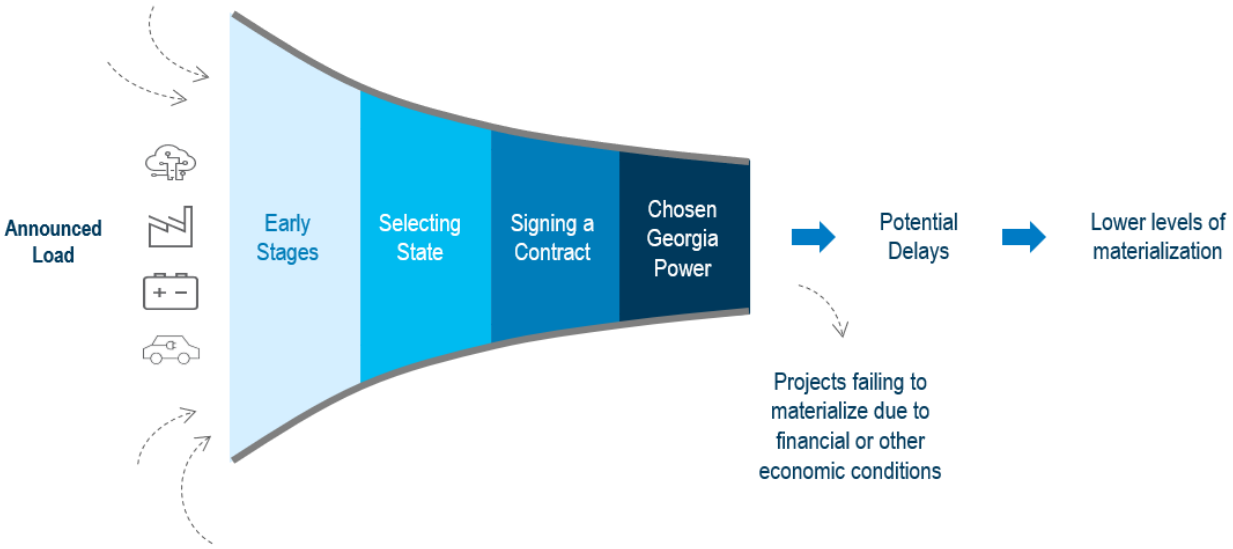
- **Commercial Operation Date ("COD")**: When the initial load is expected to start.
- **Ramp-Up**: A year-by-year load trajectory.
- **Announced Load**: The design capacity for the project load. This corresponds to the maximum load of the ramp-up schedule provided by each customer. The Company's Power Delivery organization uses this information to properly size the facilities and purchase equipment to serve the new load.
- **Class**: Industrial or commercial.
- **Segment**: This criterion corresponds to the particular segment of a business within a customer class, such as cryptocurrency, datacenter, warehouse, battery manufacturing, chemicals, and solar.

7.1.2 Modeling Project Uncertainty

Each large load project contains multiple dimensions of uncertainty that must be considered and analyzed. The first element of uncertainty to consider is whether the potential customers will choose to locate in Georgia. A customer may ultimately end up choosing a different state as the location of a project despite initial indications of interest in Georgia. If a large load customer elects to locate in Georgia, there is still uncertainty due to the competitive nature of the bidding process

for large load customers among electric service providers in the state, and a customer may choose to sign a contract for electric service ("CES") with an electric service provider other than Georgia Power. There is even some uncertainty once a customer signs a CES with Georgia Power, as the project could fail to materialize due to unforeseen circumstances such as financial or other economic conditions. In addition, based on Georgia Power's experience, the load announced by a customer is only an estimate of its metered load, which can materialize at a lower level than that at the time of the customer's initial announcement. Finally, the commercial operation date of a project can be delayed, thus causing load to materialize later than initially expected. Figure 7.1.2-1 below illustrates the Company's process and sequencing for the evaluation of uncertainties related to large load projects.

Figure 7.1.2-1: Sequencing of Large Load and Sources of Uncertainty



7.1.3 Project Success

The Company uses a probabilistic approach to account for the uncertainties described in the previous section to determine the likelihood of success or failure of an individual project. The success of a project requires each of the following three events:

i. Georgia is chosen as the location of the project.

ii. Customer signs a contract with Georgia Power for the project.

iii. The project reaches commercial operation after a contract has been signed with Georgia Power.

7.1.4 State Selection

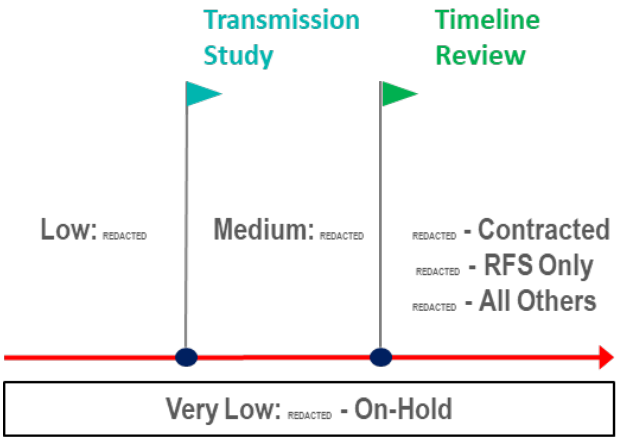
Customers often evaluate sites in multiple states before finalizing the location of a project. Mathematically, state selection can be treated as a binary event, with one (1) assigned for customers that select Georgia and zero (0) for customers that select a different state. For those customers contemplating Georgia as a place for doing business, a probability (referred to as P1) can be assigned for the likelihood of state selection. Likelihood can be estimated based on a historical selection rate that is calculated based on the number of projects that chose Georgia versus the number of projects that did not.

7.1.5 Electric Service Provider

Whether a customer signs a CES with Georgia Power can also be treated as a binary event. The probability of the customer signing a CES with Georgia Power (referred to as P2) is determined by the Company based on the following criteria and milestones (see Figure 7.1.5-1 for a visual illustration):

- REDACTED for customers that have signed a contract
- REDACTED for customers that have submitted a request for electric service ("RFS") but have yet to sign a contract
- REDACTED for projects that have completed Timeline Review but have yet to submit an RFS
- REDACTED for projects that have completed Transmission Study but have yet to complete Timeline Review
- REDACTED for projects that haven't completed Transmission Study and are not on-hold
- REDACTED for projects that are on-hold

Figure 7.1.5-1: Criteria/Milestones for P2 (Probability of Signing a CES with Georgia Power)



7.1.6 Project Reaching Commercial Operation

The probability of projects reaching commercial operation (referred to as P3) is determined by reviewing the number of projects that reached commercial operation versus the total number of projects Georgia Power was selected to serve.

For a new large load project to be considered successful, all three of the above events (i.e., state selection, signing a CES with Georgia Power, and the project reaching commercial operation) must occur. In other words, project success or failure is a binary event that is reflected by the probability formula P = P1*P2*P3.

7.1.7 Announced Load vs. Metered Load

To account for the potential difference between the metered load being served, as measured at the customer's meter, versus the load announced by the customer, the ratio (in %) between metered load and announced load is treated as a range. In the absence of actual historical data, the Company identifies minimum and maximum values for this range, as well as a most likely outcome. For example, in the case of data centers (hyperscaler), the range is between REDACTED% and REDACTED% of the

customer's announced load, with a most likely outcome of REDACTED%. Mathematically, this is modeled with a triangular distribution (see Section 7.3 for more technical details).

Table 7.1.7-1 below demonstrates the parameter inputs for modeling the metered load compared to the announced load, based on the customer class and segment.

Table 7.1.7-1: Specifications of Triangular Distributions for Metered vs. Announced

Class	***Segment***	***Low***	***Mid***	***High***
Commercial	**Cryptocurrency**	REDACTED	REDACTED	REDACTED
	Data Center (Hyperscaler)	REDACTED	REDACTED	REDACTED
	Data Center (Colocator with Tenants)	REDACTED	REDACTED	REDACTED
	Data Center (Colocator without Tenants)	REDACTED	REDACTED	REDACTED
	Data Center (Developers with Data Center Experience)	REDACTED	REDACTED	REDACTED
	Data Center (Developers without Data Center Experience)	REDACTED	REDACTED	REDACTED
	Segments Other than Data Center and Cryptocurrency	REDACTED	REDACTED	REDACTED
Industrial	**All Segments**	REDACTED	REDACTED	REDACTED

7.1.8 Commercial Operation Date Delays

Projects often experience delays in their commercial operation date. The expected delays are shown in Table 7.1.8-1 and can range between REDACTED to REDACTED months, with a most likely delay of REDACTED months. The parameter inputs for modeling the probability of delays in commercial operation are based on the Company's estimates.

Table 7.1.8-1: Specifications of Triangular Distributions for Delay

Class	***Segment***	***Low***	***Mid***	***High***
Commercial	**All segments**	**REDACTED**	**REDACTED**	**REDACTED**
Industrial	**All Segments**	**REDACTED**	**REDACTED**	**REDACTED**

7.2 MODELING THE PORTFOLIO

The portfolio of large load projects being assessed by the Company consists of projects in numerous phases of development, ranging from early stages, such as the state selection or site selection phases, to those under construction and projected to be served by the Company. This creates multiple dimensions of uncertainty for each project that requires a Monte Carlo simulation model to quantify a range of expected load to serve.

Monte Carlo simulation is a mathematical technique that is used to estimate the possible outcomes of a portfolio with uncertain events. Unlike a normal forecasting model, Monte Carlo simulation predicts a set of outcomes based on an estimated range of values versus a set of fixed input values. The simulation assigns random values to input variables with uncertainty based on probability distributions such as the triangular distributions mentioned in Section 7.1.7 and calculates an outcome. It then repeats the process over and over (at least thousands of times typically), each time using a different set of random inputs, to produce a large number of outcomes.

7.2.1 Model Implementation

The model described herein is implemented in Excel with a third-party add-in called @Risk. @Risk allows the incorporation of probability distributions into an Excel spreadsheet so that Monte Carlo simulation and analysis can be done to track the range of potential outcomes and calculate a wide array of statistics (average, standard deviation, percentiles, etc.).

For each project in the model, there are three random numbers being drawn for success/failure, metered/announced ratio, and delay in COD from the distributions described in Section 7.1. For a particular draw, if the success/failure random number is 0, or failure, the load of the project is 0 and the project is excluded from the portfolio. If the success/failure random number is 1, or success, the announced load ramp-up gets scaled by the metered/announced ratio random number and then shifted according to the timing of the ramp-up by the number of months determined by the delay in COD random number. Finally, this adjusted and shifted ramp-up is aggregated year by year into the portfolio level.

7.2.2 Simulation Results

The procedure described in Section 7.2.1 is repeated 100,000 times. Then, these 100,000 load iterations get ranked for each year in order to calculate load percentiles, which helps the Company to understand the load range and compare the likelihood of load outcomes for the portfolio. The table below shows the external adjustments included in the February 2025 Load Forecast, which are consistent with the 50^{th} percentile of simulated load.

7.2.3 External Peak Adjustments for Large Loads

The large load data center energy forecast from the LRM (i.e., the 50^{th} percentile of simulated load described in section 7.2.2) gets a data center load shape applied to it to get hourly load values. These values are then added to the organic hourly load forecast values for the commercial class load and resulting class peak. Similarly, the energy forecast for new large load industrial customers gets an industrial load shape applied to it, and the hourly values are added to the baseline organic hourly load forecast to get the total industrial class peak.

Table 7.2.1 February 2025 LRM Output and External Summer Peak Adjustments for Large Loads

Year	LRM Output	Large Load Peak Adjustment
2025	**REDACTED**	**REDACTED**
2026	**REDACTED**	**REDACTED**
2027	**REDACTED**	**REDACTED**
2028	**REDACTED**	**REDACTED**
2029	**REDACTED**	**REDACTED**
2030	**REDACTED**	**REDACTED**
2031	**REDACTED**	**REDACTED**
2032	**REDACTED**	**REDACTED**
2033	**REDACTED**	**REDACTED**
2034	**REDACTED**	**REDACTED**
2035	**REDACTED**	**REDACTED**
2036	**REDACTED**	**REDACTED**
2037	**REDACTED**	**REDACTED**
2038	**REDACTED**	**REDACTED**
2039	**REDACTED**	**REDACTED**
2040	**REDACTED**	**REDACTED**
2041	**REDACTED**	**REDACTED**
2042	**REDACTED**	**REDACTED**
2043	**REDACTED**	**REDACTED**
2044	**REDACTED**	**REDACTED**

7.3 TRIANGULAR DISTRIBUTION

The triangular distribution is a continuous probability distribution with the following parameters:

a: $a \in (-\infty, \infty)$

b: $a < b$

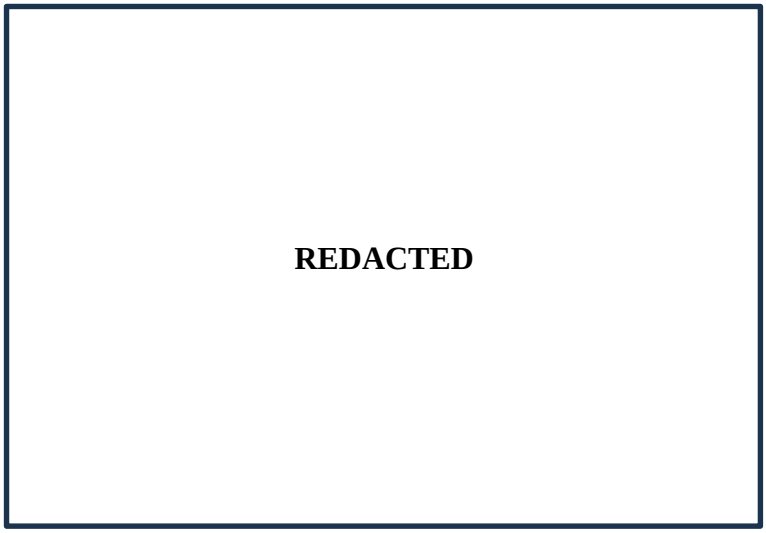
c: $a \leq c \leq b$

In the case of metered versus announced uncertainty, *a* represents the minimum metered/announced ratio, *b* represents maximum metered/announced ratio and *c* represents the most likely metered/announced ratio.

Figure 7.3-1: Probability Density Function for a Triangular Distribution



Figure 7.3-2: Probability Density Function of Triangular Distribution with a= 60%, c=75% and b=90%



Triangular distributions are chosen for this model for the following reasons:

- A triangular distribution has a finite range while other commonly used probability distributions such as normal and lognormal distributions have an infinite range and can even be negative, which is inappropriate to depict the actual/announced ratio.
- The min/max/most likely parametric setup of triangular distributions is intuitive and straightforward to interpret. In contrast, the parameters of some other commonly used distributions are somewhat opaque. For example, normal distributions are defined in terms of mean and standard deviation. Additional calculations are needed to translate those into the range of outcomes that are more appropriate for the context of actual vs. announced load.
- Other than the standard min/max/most likely parametric setup, triangular distributions can also be defined by a combination of percentiles, min, max and most likely, which offers more flexibility to fine tune the model.