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**

DIRECT TESTIMONY AND EXHIBITS

OF

DOUGLAS A. SMITH AND
SASIKUMAR KANNAN

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

PUBLIC DISCLOSURE

MAY 5, 2025

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Staff Exhibit #	**Description**
Exhibit_SP-1	Resume for Douglas A. Smith
Exhibit_SP-2	Resume for Sasikumar Kannan

I. INTRODUCTION

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

A. This testimony is jointly offered by Douglas A. Smith and Sasikumar Kannan, both from Daymark Energy Advisors, Inc. (Daymark). Mr. Smith is a Principal Consultant and Mr. Kannan is a Lead Engineer. Our business address is 370 Main Street, Suite 325, Worcester, Massachusetts 01608.

Q. PLEASE SUMMARIZE DAYMARK'S BUSINESS.

A. Daymark provides energy planning, market analysis, and regulatory policy consulting and advisory services to support decision making within the electricity and natural gas industries. We serve a broad range of clients in North America, including private and public utilities, energy producers and traders, energy consumers and consumer advocates, regulatory agencies and public policy and energy research organizations, and other industry stakeholders. Our technical skills include power market forecasting models and methods, economics, management, planning, rates and pricing, and energy procurement, and contracting. Our experience includes detailed analyses of energy and environmental performance of the electric systems, economic planning for transmission, and market analytics.

Q. MR. SMITH, PLEASE SUMMARIZE YOUR EXPERIENCE AND QUALIFICATIONS.

A. I have over twenty years of experience in the energy industry, primarily supporting clients' efforts to advance or review infrastructure projects. I have advised clients regarding competitive transmission project development, including determination of need, solution building and outreach to stakeholders. I have led evaluations of proposed transmission projects, including assessment of regional benefits, in SPP, PJM, NYISO, ISO-NE and in the province of Manitoba. I have also evaluated non-wires alternatives in Vermont and Maine. Additional detail on my experience and qualifications is provided in my resume, attached hereto as Exhibit_SP-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified in the docket regarding Georgia Power Company's 2023 Integrated Resource Plan ("IRP") Update as well as Georgia Power Company's Application For Certification of the Robins, Moody, Hammond, and McGrau Ford Phase I and II Battery Energy Storage Systems,

Q. MR. KANNAN, PLEASE SUMMARIZE YOUR EXPERIENCE AND QUALIFICATIONS.

A. I have over ten years of experience in the electric power industry, focusing on power system planning, transmission analysis, and regulatory support. I have led and contributed to transmission planning studies, interconnection assessments, and competitive transmission project development efforts across ISO-NE, PJM, and other regions. My work has included evaluation of grid needs, development of technical solutions, and support for regulatory filings and stakeholder engagement. I have experience conducting detailed power system modeling and have worked with a range of tools including PSS®E, TARA, and PSCAD. Prior to my current role, I worked at ISO New England supporting dynamic modeling and stability analysis for regional planning studies. Additional details on my experience and qualifications are provided in my resume, attached hereto as Exhibit_SP-2.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No, I have not.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. We are testifying on behalf of the Public Interest Advocacy Staff ("Staff") of the Georgia Public Service Commission ("Commission"). The purpose of our testimony is to respond to certain elements of Georgia Power Company's ("Company" or "Georgia Power") 2025 Integrated Resource Plan ("IRP") filing. We address issues pertaining to the Company's transmission planning processes and the resulting proposed investments.

We reviewed the Company's analysis and conclusions related to the transmission system upgrades proposed in the IRP filing. Our scope included a thorough review of the Company's assumptions, methodology, and conclusions, including a review of the power flow analyses conducted by the Company in support of its filing.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Our recommendations are as follows:

1. **Evaluate the Risk of Overbuilding Due to Area Max Scenarios** Georgia Power uses "Area Max" scenarios to assess whether the transmission system can accommodate the full simultaneous output of all generators within a defined region. While this method supports firm deliverability and ensures that generation is not "trapped" in constrained areas, it also reflects extreme, infrequent system conditions that may never occur in practice.

   We recommend that any transmission project primarily justified by Area Max scenario results be subject to a formal cost-benefit analysis comparing the lifetime cost of infrastructure upgrades to the operational cost of more flexible solutions—such as controlled curtailment, redispatch, or special protection schemes. This cost-benefit assessment should be reviewed by an independent third party to ensure transparency and analytical rigor. Projects should only proceed where the infrastructure cost is clearly justified relative to feasible operational alternatives.

2. **Supplement Economic Dispatch (ED) with Security-Constrained Dispatch Analysis**

   The Economic Dispatch (ED) analysis used by Georgia Power for transmission planning is not security-constrained, potentially overstating transmission congestion and infrastructure needs. To better reflect realistic operational practices, the Company should supplement ED scenarios with security-constrained dispatch sensitivities. Specifically, after identifying potential violations through ED analysis, Georgia Power should perform security-constrained dispatch runs and evaluate whether operational measures, including remedial action schemes or targeted generation curtailments, could provide more cost-effective solutions. This approach would reduce the risk of investing in unnecessary transmission upgrades by accurately reflecting feasible operational alternatives.

3. **Implement a Formal Screening Process for Grid-Enhancing Technologies (GETs)**

   Georgia Power has taken encouraging steps toward integrating Grid-Enhancing Technologies (GETs) into its system, including pilot deployments of Dynamic Line Ratings (DLR), the installation of advanced conductors, and the use of modular power flow control devices. However, we believe Georgia Power can do more to make GETs a systematic and transparent part of its transmission planning process. GETs like DLR, flow control devices, and topology optimization are proven, mature technologies widely used across the U.S. and internationally to boost capacity and defer traditional upgrades. Georgia Power should adopt a formal, system-wide process to evaluate these tools as potential solutions for all major transmission projects.

   Further, we recommend that the Company publicly report on the planning assumptions, criteria, and outcomes associated with its GET evaluations—particularly as it continues to receive federal support for these deployments. Such transparency would not only improve stakeholder confidence but position Georgia Power as a national leader in innovative grid planning.

4. **Evaluate Non-Wires Alternatives (NWAs), Including SATOAs**

   non-wires alternatives such as Storage as Transmission-Only Assets (SATOAs), distributed generation, and demand-side solutions have not been routinely assessed in Georgia Power's IRP transmission planning. We recommend that the Commission direct Georgia Power to incorporate NWA screening into its standard project development process. This would include technical and economic evaluations of SATOAs as potential substitutes for traditional line or substation builds, especially in constrained or rapidly growing areas.

5. Align Transmission Planning Studies with Updated IRP Load Forecasts

To improve responsiveness to changing conditions, Georgia Power should either incorporate load sensitivity scenarios during the Ten-Year Plan (TYP) process or apply high-level screening in the IRP to reassess transmission needs using updated forecasts.

This would allow the Company to flag material differences between earlier assumptions and current forecasts, especially where new large loads may accelerate or delay infrastructure needs. Incorporating this step can reduce the risk of over-building or under-building and ensure transmission investments remain aligned with actual system requirements.

Q. PLEASE EXPLAIN HOW THE REMAINDER OF THE TESTIMONY IS ORGANIZED.

A. Section II provides an overview of the Company's filing as it pertains to the transmission investment sought. Section III discusses the 2024 Georgia Integrated Transmission System ("ITS") Ten-year Plan ("TYP"), Section IV discusses Daymark's analysis of the TYP and Section V provides some recommendations regarding the use of the TYP in the Company's IRP. Section VI presents observations and recommendations regarding the Company's use of Grid Enhancing Technologies ("GETS").

II. OVERVIEW OF COMPANY FILING

Q. PLEASE SUMMARIZE THE COMPANY'S FILING RELATED TO PROPOSED TRANSMISSION INVESTMENTS.

A. Georgia Power's 2025 IRP filing includes a comprehensive transmission plan built around the 2024 Georgia ITS TYP. The IRP's transmission-related filing consists of:

(i) The full 2024 ITS TYP, which identifies specific transmission projects over 2024-2033 needed to meet forecasted load growth and generation changes,

(ii) Updates on strategic transmission project*s* initiated since the 2023 IRP Update, and

(iii) Discussion of future grid needs beyond the 10-year horizon.

The IRP incorporates both the baseline transmission expansion identified in the 2024 TYP and a set of additional strategic projects developed in response to more recent system needs. Table 11.3 of the IRP highlights 23 strategic transmission projects—primarily 230 kV and 500 kV lines—that were developed in coordination with ITS Participants since the 2022 IRP. These projects aim to strengthen South-to-North transfer capability, accommodate future generation shifts, and support areas experiencing substantial projected load growth. While many of these projects were previously considered in recent TYP cycles, their inclusion in the IRP reflects the Company's effort to reaffirm and advance planning for long-lead infrastructure needed to maintain system reliability through the early 2030s.[1]

Beyond the standard 10-year transmission planning process, the IRP describes an evolving approach to long-term planning. This includes early-stage modeling to identify infrastructure needed to accommodate rapid economic development, integrate renewable

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[1] 2025 IRP Main Document, Table 11.3, p. 113.

resources, and maintain grid flexibility as system conditions shift.[2] The Company indicates that this longer-term view is necessary to meet future transmission needs with sufficient lead time, and that it will increasingly inform regional coordination efforts and support strategic decision-making.

Georgia Power states that these investments are needed to reliably serve approximately 8 GW of projected new load by Winter 2030/31, integrate new generation additions, and remain in compliance with applicable North American Electric Reliability Corporation ("NERC") reliability standards.[3] Through this filing, the Company requests Commission approval of the transmission plan as presented in the IRP, recognizing that while individual transmission projects are not approved in this docket, the overall transmission development strategy is an essential component of the resource plan.

III. DISCUSSION OF THE 2024 GEORGIA ITS TEN-YEAR PLAN ("TYP")

Q. PLEASE SUMMARIZE THE 2024 GA ITS TYP PROCESS.

A. The 2024 Georgia ITS TYP is the product of a coordinated annual transmission planning process conducted jointly by the ITS Participants—Georgia Power Company, Georgia Transmission Corporation, MEAG Power, and Dalton Utilities. The objective of the TYP is to identify and recommend transmission improvements necessary to reliably serve projected electric demand across the ITS footprint over a ten-year planning horizon, in accordance with NERC standards and state regulatory requirements.

[2] 2025 IRP Main Document, Chapter 11.2, pp. 111–112.
[3] 2025 IRP Main Document, Chapter 11.2, p. 111–112

The TYP is built on a structured analytical foundation. ITS Participants contribute updated data each year, including load forecasts, generation expansion plans, power transfer commitments, and interconnection needs. This information is used to construct load flow base cases for each of the next ten years. These cases simulate steady-state system performance and are evaluated under normal and contingency (N-1)[4] conditions to identify thermal overloads, voltage violations, and stability concerns. In addition to steady-state analyses, stability and short-circuit studies are conducted to ensure the system remains secure under transient conditions and fault scenarios. [5]

When potential violations are identified, alternative solutions—including new lines, upgrades, reactive support, or operational guides—are developed and screened for cost-effectiveness, feasibility, and compliance with ITS planning guidelines. This solution identification process is iterative and informed by a set of guiding principles that prioritize reliability, economic efficiency, use of existing assets, and coordination among ITS Participants.

The finalized TYP includes a detailed list of projects, categorized by voltage class, need date, and justification, and is approved through consensus among ITS Participants. The results of the TYP are submitted to the Georgia Public Service Commission for approval and are incorporated by Georgia Power into its IRP.

[4] An "N-1 contingency" refers to the unexpected loss of a single system element (such as a transmission line, transformer, or generator), with the expectation that the system will remain within operational limits and avoid cascading failures.

[5] 2025 IRP Volume 3, I.T.S. Planning Procedure No. 9, p. 18-24

In summary, the 2024 TYP ensures that transmission infrastructure keeps pace with evolving system needs, enabling the delivery of reliable and cost-effective electric service across Georgia.

Q. **WHAT IS THE PURPOSE OF THE 2024 GA ITS TYP IN THE CONTEXT OF THE COMPANY'S 2025 IRP**?

A. The 2024 Georgia ITS TYP serves as the foundational transmission planning document that informs and supports the transmission assumptions made in Georgia Power's 2025 IRP.

The 2024 TYP provides the starting point — establishing the transmission system's ability to meet known and reasonably expected reliability needs — but the 2025 IRP builds upon the 2024 TYP by identifying additional "strategic" projects deemed necessary to address more aggressive load growth and generation development scenarios that emerged after the TYP's finalization.

In summary, the purpose of the 2024 ITS TYP is to form the backbone of the Company's transmission reliability planning for the IRP period, while the 2025 IRP supplements it to account for new large load drivers and future resource integration needs that have developed more recently. Together, they are designed to ensure that both baseline and forward-looking system requirements are addressed to maintain reliable and economic electric service.

Q. HOW DOES THE 2024 TYP ALIGN WITH, OR DIFFER FROM, THE COMPANY'S 2025 IRP ASSUMPTIONS?

A. While the 2024 ITS TYP forms a foundational basis for the Company's 2025 IRP, there are key differences driven by the load forecast assumptions underlying each document. Specifically, the 2024 TYP was developed using the B2024 load forecast,[6] whereas the 2025 IRP utilizes the B2025 forecast,[7] which reflects significantly higher large customer load expectations due to evolving economic development activity and updated customer commitments.

Since the B2025 forecast incorporates more recent information, including additions to the large load pipeline—some areas modeled in the IRP reflect higher anticipated peak demand than those studied in the earlier TYP. This divergence illustrates the importance of maintaining flexibility in transmission planning to reflect current assumptions and to avoid under- or over-building infrastructure as system needs evolve.

Q. WHAT ARE YOUR CONCERNS REGARDING THE LOAD FORECAST USED IN THE TRANSMISSION PLANNING ANALYSIS?

A. The primary concern is the unprecedented magnitude of the projected load growth and the associated uncertainty. Georgia Power forecasts approximately 8 GW of additional winter peak load by 2030/2031 compared to prior projections. Acknowledging uncertainty in the materialization of the Company's load forecast,[8] the transmission plan is limited in its ability to precisely plan to a particular load level.

An additional concern arises because the 2024 TYP was developed using the B2024 load forecast, whereas the 2025 IRP uses the updated B2025 forecast. The B2025 forecast

[6] 2025 IRP Volume 3, Section D1, p. 26
[7] 2025 IRP Main Document, Chapter 5, p.35
[8] Uncertainty regarding the Company's B2025 load forecast is discussed in a separate Staff panel

incorporates significant revisions based on updated customer commitments and economic activity as of mid-2024. As a result, transmission studies conducted for the IRP may reflect materially higher load levels in certain areas than those used to develop the 2024 TYP. The extended duration required to fully develop the TYP further complicates timely updates in response to rapidly evolving load forecasts. Given the pace and magnitude of potential load changes, conducting additional sensitivity analyses around various plausible future scenarios would be beneficial. Incorporating scenario analysis more extensively into the TYP process would capture the impact of significant uncertainties in a timely manner, enabling more responsive planning decisions and better information-sharing during the IRP development process. Such proactive scenario evaluations would allow Georgia Power greater flexibility in aligning transmission investments with actual customer load growth and commitments, reducing the risk of unnecessary or premature infrastructure expenditures.

Q. PLEASE SUMMARIZE HOW THE 2024 GA ITS TYP CASES WERE DEVELOPED.

A. The 2024 Georgia ITS TYP cases were developed through a structured, iterative process led by the ITS Participants, including Georgia Power Company, Georgia Transmission Corporation, MEAG Power, and Dalton Utilities. Each participant contributed baseline load forecasts, generation additions and retirements, and firm power transfer commitments for their respective systems. For Georgia Power specifically, the forecasts were developed using the Load Realization Model, which incorporated expected large load additions based on their probability of realization and timing. [9]

Initial modeling emphasized directional stress scenarios, such as heavy South-to-North and West-to-East flows. These cases were dispatched using an Economic Dispatch ("ED") program developed by Georgia Power.[10] The ED program performs least-cost dispatch of generation resources but is explicitly not security-constrained—it does not account for transmission limitations during dispatch. This approach allows planners to identify potential system constraints that could emerge under economically optimal but electrically unrealistic conditions.[11]

Following dispatch, planners applied high-output stress tests, such as Area Max scenarios (full output generation scenarios in specific regions), and conducted N-1 contingency analyses to identify thermal overloads or voltage violations. Solutions such as new lines, reconductoring, substation enhancements, or reactive additions were developed and modeled iteratively to resolve any identified violations. This process was coordinated across ITS Participants to ensure alignment on joint project needs and timing.

Q. PLEASE DESCRIBE HOW LARGE LOADS ARE MODELED IN THE 2024 GA ITS TYP CASES.

A. As mentioned above, Georgia Power forecasts approximately 8 GW of load growth by winter 2030/2031. In the transmission studies, these loads are placed at specific substations according to expected size and timing. If the added load creates reliability concerns,

[9] 2025 IRP Main Document, Attachment E, Section E.1.6, p. 137
[10] 2025 IRP Volume 3, Section A.8, p. 33
[11] Company Response to Docket Nos. 56002 & 56003 STF-DEA-2-5 Attachment

upgrades are planned to address them. This method aims to align transmission investments with likely customer growth while minimizing unnecessary infrastructure.

Q. CAN YOU IDENTIFY TRANSMISSION PROJECTS THAT MAY NOT BE NEEDED IF LARGE CUSTOMER LOADS DO NOT FULLY MATERIALIZE OR ARE DELAYED?

A. Yes. Several strategic transmission projects identified in Georgia Power's 2025 IRP are closely linked to assumptions regarding significant future load growth, particularly from large industrial and data center customers. If these loads do not fully materialize or are delayed, the timing and justification for some of these projects may warrant reassessment. Projects such as the Ashley Park–Wansley 500 kV, Farley–Tazewell 500 kV, and McGrau Ford–Middle Fork 500 kV lines are explicitly categorized as strategic initiatives and are driven in large part by forecasted regional demand growth and long-term grid flexibility needs.[12] These investments are intended to provide high-capacity corridors and improve reliability in areas with projected rapid development, particularly metro Atlanta and South Georgia. However, if the associated large customer developments are postponed or canceled, the need for immediate infrastructure buildout could diminish.

Similarly, the Hatch–Wadley 500 kV project is referenced as a reinforcement to improve northward transfer capability and integrate potential generation resources in South Georgia.[13] However, if the associated load and generation development does not proceed as forecasted, the project's justification may need to be revisited.

[12] 2025 IRP Volume 3 TRADE SECRET, Section D.1, p. 272-297
[13] 2025 IRP Volume 3 TRADE SECRET, Section D.1, p. 283

As noted in the Company's discovery responses, load additions were modeled using Georgia Power's Load Realization Model, which includes a range of customer commitments with varying levels of certainty. Many large load projects were modeled in the IRP at full levels, whereas in earlier planning stages, they may have been omitted or included at reduced levels. This variation underscores the importance of aligning transmission investment timing with confirmed customer milestones.

To ensure that proposed transmission assets are meeting load from materializing customers, it would be appropriate for the Commission to require the Company to periodically report on the development status of large customer projects that underpin major transmission upgrades. If such projects are delayed or canceled, the related transmission investments should be reconsidered for deferral or adjustment.

Q. EXPLAIN THE PURPOSE OF AREA MAX SCENARIOS IN TRANSMISSION PLANNING AND WHETHER THEIR USE COULD LEAD TO OVER-BUILDING.

A. The "Area Max" scenario is a transmission planning sensitivity in which all generators with long-term firm transmission service in a specific region (often referred to as a "generation pocket") are modeled to operate at their full output simultaneously.[14] This dispatch assumption is used to identify whether sufficient transmission capacity exists to export generation from the area without curtailment under single-contingency (N-1) conditions.

The purpose of the Area Max scenario is to ensure that generation is not "trapped" behind transmission constraints, especially in regions where significant new generation is

[14] 2025 IRP Volume 3, I.T.S. Planning Procedure No. 9, p. 4

expected.[15] By testing the system under these conditions, the Company seeks to maintain a high standard of reliability and ensure dependable physical delivery for transmission customers.

However, this approach can present a risk of overbuilding. The simultaneous full-output condition modeled in Area Max scenarios is not likely to occur frequently in real-time operations, particularly given economic dispatch practices that prioritize the lowest-cost resources and respond dynamically to system conditions. Planning to avoid any curtailment under this rare scenario can drive investments that exceed what may be needed under more probable operating conditions.

The Company acknowledges that the goal of this planning method is to provide firm physical transmission service that is rarely curtailed, even in the event of transmission outages or generator failures. Yet this standard does not explicitly consider alternative operational strategies — such as redispatch, partial curtailments, or remedial action schemes — which might offer more cost-effective solutions in certain cases.

In summary, while Area Max scenarios are a reasonable tool to test for worst-case reliability risks, their rigid application may lead to overbuilding if not balanced with operational flexibility and a realistic assessment of actual generator dispatch patterns.

Q. ARE THERE ALTERNATIVES TO INFRASTRUCTURE INVESTMENT THAT COULD BE CONSIDERED IN SUCH CASES?

A. It is recommended that operational solutions, such as Special Protection Schemes (SPS) or Remedial Action Schemes (RAS), be evaluated as alternatives before defaulting to major transmission upgrades in response to Area Max findings. In cases where an Area Max

[15] 2025 IRP Volume 3, I.T.S. Planning Procedure No. 9, p. 4

contingency reveals an overload that would occur only under very unlikely conditions, a more proportionate response may involve developing operating guides, limited generator redispatch protocols, or other non-wires solutions.

Further, it would be prudent that any transmission project primarily justified based on an Area Max scenario undergo additional scrutiny, including an independent review to assess whether the identified risk justifies the cost of the proposed solution. This approach would help balance system robustness with affordability, ensuring that ratepayers are protected from paying for infrastructure aimed at conditions that are unlikely to materialize with any frequency.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE USE OF THE ECONOMIC DISPATCH TOOL.

A. The Economic Dispatch (ED) tool used by Georgia Power interfaces with power flow models to economically allocate generation among online units after specific scenario conditions are imposed, such as simulating a unit outage or maximizing output in a geographic area ("Area Max" cases).[16] The ED tool aims to equalize the incremental cost of all online generators to achieve an economically efficient dispatch under the scenario assumptions.

However, the ED tool is explicitly not security constrained. It does not account for thermal, voltage, or stability limits on the transmission network while dispatching generation.[17]

[16] Company Response to Docket Nos. 56002 & 56003 STF-DEA-2-4 Attachment
[17] Company Response to Docket Nos. 56002 & 56003 STF-DEA-2-5 Attachment

Instead, the dispatch is performed first based purely on generation costs, and only afterward is contingency analysis run to identify overloads and voltage violations.

Because the dispatch phase does not recognize transmission constraints, it can create highly stressed or unrealistic network conditions. Overloads or reliability violations identified after dispatch may reflect an artificially extreme dispatch scenario that would not occur under real-time operational practices, where system operators would proactively adjust generation dispatch to avoid reliability issues.

As a result, the reliance on ED-driven violations may overstate the need for transmission infrastructure solutions. This planning approach implicitly assumes that any constraint encountered after economic dispatch must be resolved by building new facilities, rather than by considering operational mitigations such as redispatch agreements or temporary corrective actions.

The use of a non-security-constrained ED tool is appropriate for identifying potential system weaknesses under stressed conditions; however, planning decisions based solely on these results without further risk-based evaluation can lead to unnecessary or premature transmission investments.

It is recommended that transmission planning results derived from the ED analysis be complemented by a security-constrained dispatch analysis as a sensitivity study. Such security-constrained analyses explicitly include transmission constraints during the dispatch process, providing more realistic operational outcomes. The results of both dispatch methods should then be compared economically to determine whether alternative solutions—such as remedial action schemes, operational redispatch, or controlled curtailment—represent a more cost-effective solution compared to infrastructure upgrades, particularly for resolving infrequent or marginal transmission issues.

IV. THE COMPANY'S USE OF GRID ENHANCING TECHNOLOGIES SHOULD CONTINUE TO EVOLVE AS A FOCUS FOR FUTURE PLANNING

Q. DESCRIBE HOW GEORGIA POWER DEFINES GRID-ENHANCING TECHNOLOGIES (GETS), AND HOW THAT COMPARES TO INDUSTRY DEFINITIONS.

A. Georgia Power defines Grid-Enhancing Technologies (GETs) as a portfolio of technologies designed to enhance the flexibility, efficiency, and capacity of the transmission system—particularly in support of integrating inverter-based resources. Some GETs work by increasing the physical transfer capacity of transmission assets (e.g., advanced conductors and DLR), while others improve the utilization of existing infrastructure by managing power flows or optimizing grid topology under different operating conditions. The Company's categorization includes Dynamic Line Ratings (DLR), modular power flow control devices, topology optimization, and the use of advanced conductors, following Electric Power Research Institute (EPRI) standards.[18] This definition is broadly consistent with the industry view adopted by organizations such as the National Association of Regulatory Utility Commissioners (NARUC) and the U.S. Department of Energy (DOE), which emphasize DLR, flow control, and topology

[18] 2025 IRP Volume 3, Section A.6, p19

optimization as core GETs technologies ("Utility regulators want more grid-enhancing tech for reliability"). While some industry frameworks treat advanced conductors and energy storage as distinct categories, Georgia Power appropriately includes advanced conductors within its GETs framework, aligning with prevailing national definitions.

Q. HAS GEORGIA POWER EFFECTIVELY IMPLEMENTED GRID-ENHANCING TECHNOLOGIES INTO ITS TRANSMISSION PLANNING?

A. Georgia Power has made measurable progress in deploying Grid-Enhancing Technologies (GETs) across its transmission system. The Company has installed advanced conductors, deployed a STATCOM in 2024, and partnered with LineVision to pilot Dynamic Line Ratings (DLR) aimed at increasing real-time situational awareness and transmission capacity. Additionally, Georgia Power has secured $160 million in federal Department of Energy (DOE) funding to further support GET deployment.

Power flow controllers have been evaluated in multiple projects—primarily at the 115 kV level—and were actively selected in some cases. A notable example includes the installation of Smart Wires' SmartValve devices at East Villa Rica Switching Station. These modular flow control devices were deployed to relieve thermal constraints and defer the need for a more capital-intensive strategic project at [redacted].[19] This illustrates a practical application where GETs were chosen to address system needs in a cost-effective, flexible manner.

That said, while Georgia Power has incorporated GETs into some project evaluations, there is no consistent indication that these technologies are systematically screened across all

[19] 2025 IRP Volume 3 TRADE SECRET, Section D.1, p. 166

voltage levels or project types, including higher-voltage, load-driven infrastructure. Planning documentation does not reflect a transparent methodology for determining where and when GETs are preferred over traditional upgrades.

Accordingly, Georgia Power's efforts place it somewhere in the middle of the pack nationally—engaged and forward-looking in certain areas, but not yet at a level of integration that reflects the full potential of GETs as outlined in recent DOE studies and industry best practices. A more structured and comprehensive evaluation process would allow the Company to maximize the cost, performance, and timing benefits these technologies can offer.

Q. HOW COULD GEORGIA POWER BETTER INTEGRATE GRID-ENHANCING TECHNOLOGIES INTO ITS TRANSMISSION PLANNING PROCESS?

A. Georgia Power should formalize a structured and transparent methodology for evaluating GETs and non-wires alternatives (NWAs) as part of its transmission planning process. While the Company has considered power flow controllers in select projects and is piloting Dynamic Line Ratings in collaboration with LineVision,[20] these efforts have not been systematically applied across the broader project portfolio.

To improve the integration of GETs, the Company should:

(i) incorporate screening for GETs into each major project's evaluation;

(ii) establish thresholds to assess cost-effectiveness and system impact; and

(iii) expand the use of DLR, power flow controllers, and topology optimization in both planning studies and operations.

[20] https://www.linevisioninc.com/news/linevision-deploying-advanced-grid-technology-with-georgia-power

Further, Georgia Power's receipt of substantial DOE funding should come with an expectation of measurable results. The Commission should require regular reporting on GET-related impacts—such as avoided capital projects, capacity increases, and congestion mitigation—to validate that ratepayer-funded grid enhancements are yielding intended benefits.

Given the scale and pace of forecasted load growth, a robust GETs strategy is essential to ensure that Georgia Power can maintain system reliability while containing costs.

Q. ARE THERE EXAMPLES FROM OTHER REGIONS THAT DEMONSTRATE THE BENEFITS OF GRID-ENHANCING TECHNOLOGIES?

A. Yes. In the Southwest Power Pool (SPP), Dynamic Line Rating pilot projects demonstrated the ability to increase transmission line capacity significantly, allowing the deferral of major rebuild projects. In the Northeast United States, utilities have deployed modular flow control devices to redirect flows around congested interfaces, achieving substantial customer savings by avoiding or delaying reconductoring projects. Internationally, the United Kingdom's (UK) National Grid system extensively uses power flow control devices to maximize transmission asset utilization and defer costly network expansions.

These examples confirm that Grid-Enhancing Technologies are mature, proven solutions that can materially enhance grid reliability and efficiency when properly integrated into planning and operations.

Q. DID GEORGIA POWER CONSIDER NON-WIRES ALTERNATIVES IN ITS TRANSMISSION PLANNING?

A. A review of Georgia Power's 2025 IRP and discovery responses does not indicate that NWAs—including Storage as Transmission-Only Assets (SATOAs)—were systematically evaluated as substitutes for proposed transmission upgrades. While the Company has acknowledged growing investments in storage and demand response on the generation side, these resources were not explicitly assessed for transmission purposes.

SATOAs are increasingly recognized as viable options to relieve congestion, support voltage, and defer traditional infrastructure. In principle, Georgia Power could leverage such solutions to address localized reliability needs, particularly in areas facing large industrial load growth. However, there is no evidence in the record of technical or economic evaluation of battery-based NWAs for any transmission project, suggesting a missed opportunity to consider more flexible or cost-effective alternatives.

Q. DOES THIS CONCLUDE STAFF'S TESTIMONY?

A. Yes.