

May 2, 2025

VIA ELECTRONIC DELIVERY

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334

**Re: Direct Testimony on Behalf of Georgia Interfaith Power & Light and Southface
Energy Institute; Docket No. 56002, 56003**

Dear Ms. Tanner:

Please find enclosed an electronic version of the following **Direct Testimony of Anjali Patel on behalf of Georgia Interfaith Power & Light and Southface Energy Institute** to be filed in Docket No. 56002 and 56003.

Respectfully submitted,



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**STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

In Re:)	
)	
Georgia Power Company's 2025)	DOCKET NO. 56002
Integrated Resource Plan)	
)	
Georgia Power Company's 2025)	
Application for Certification,)	DOCKET NO. 56002
Decertification, and Amended Demand-)	
Side Management Plan)	

**DIRECT TESTIMONY OF ANJALI G. PATEL
ON BEHALF OF
GEORGIA INTERFAITH POWER & LIGHT AND
SOUTHFACE ENERGY INSTITUTE**

May 2, 2025

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1 **I. INTRODUCTION**

2 **Q. PLEASE STATE YOUR NAME, OCCUPATION, AND THE PURPOSE OF**
3 **YOUR TESTIMONY.**

4 A. My name is Anjali G. Patel, and I am the Vice President for Clean Energy with David
5 Gardiner and Associates (“DGA”). My testimony addresses why the Georgia Public
6 Service Commission (“Commission”) should direct Georgia Power Company (“Georgia
7 Power”) to engage in cost-effective, proactive, multi-value, and informed transmission
8 planning and development.

9 Transmission is an integral component of the electric network, and Georgia Power is at a
10 pivotal point in time where it must build out and modernize its transmission network to
11 protect against extreme weather, replace aging infrastructure, and meet projected
12 unprecedented growth in energy demand, all in a manner that does not overburden
13 billpayers. Transmission expansion and modernization are necessary. But insufficient or
14 poorly planned transmission can lead to unreasonable increases in customer rates,
15 unreliable service, national security concerns, and missed economic opportunities for the
16 state. My testimony addresses why Commission action is needed to advance infrastructure
17 that serves the public interest and is built smart from the start.

18 **Q. WHAT DO YOU MEAN BY “COST-EFFECTIVE TRANSMISSION PLANNING**
19 **AND DEVELOPMENT”?**

20 A. The end goal of sound transmission policy is to build the *right set* of projects to reliably
21 and affordably serve electric customers. A cost-effective network is one in which all grid
22 investments—generation, transmission, and grid-enhancing technologies—are designed to
23 maximize customer benefits while minimizing overall bills. Although transmission is “the
24 great connector”—providing a highway between generation sources and the load that
25 consumes that power—it is one component within the integrated electric network. As such,
26 transmission cost-effectiveness should not be measured solely by the capital cost of a
27 transmission project, but instead by the multiple quantifiable benefits that it can provide to
28 customers, such as increasing access to low-cost power sources and improving grid
29 resiliency. Moreover, cost-effectiveness should consider the technology being deployed

(both with respect to the transmission line as well as the supporting structures) to ensure that the chosen technologies are maximizing capacity and hardening the grid from physical and cyber threats so that additional reinvestment is not required in the near term.

Georgia Power's customers have no choice but to purchase electricity from Georgia Power and bear the costs associated with such service. At a time of such unprecedented upheaval in the electric sector, customer bills can quickly get out of hand if Georgia Power does not adapt its planning processes to meet this moment. And as the Commission is the backstop for customers, it is important that the Commission's processes review proposed infrastructure plans for overall cost-effectiveness.

Q. WHAT DO YOU MEAN BY THE PHRASE “PROACTIVE AND MULTI-VALUE TRANSMISSION PLANNING AND DEVELOPMENT”?

A. The purpose of proactive multi-value planning and development is to expand the transmission grid's capacity in a manner that neither unreasonably overbuilds nor requires additional reinvestment in the near term. Proactive and multi-value planning requires a transition from traditional reactive planning processes—which are based primarily on identified past or near-term reliability violations—to planning processes that also incorporate consideration of the economic value and energy system benefits of adding transmission. In so doing, proactive and multi-value planning integrates a broader set of planning inputs, including:

- multiple potential load scenarios;
- expected and potential changes to generation mixes; and
- impacts on reliability and system resilience to ensure power is available under both blue-sky conditions and in times of stress.

Utilities around the country are transitioning to proactive and multi-value planning processes because they recognize that such planning better accounts for the long expected lives of transmission assets (50 to 70 years).¹ And like Georgia Power, they are predicting

¹ See, e.g., U.S. Dep't of Energy, *What does it take to modernize the U.S. electric grid?*, <https://www.energy.gov/gdo/articles/what-does-it-take-modernize-us-electric-grid> (last visited Apr. 22, 2025) (“70 percent of transmission lines are over 25 years old and approaching the end of their typical 50–80-year

1 exponential near-term load growth, but are uncertain whether that load growth will actually
2 materialize, and if it does, they are unsure about the exact quantity, timing, and longevity
3 of such growth.

4 **Q. WHAT DO YOU MEAN BY THE PHRASE “INFORMED TRANSMISSION**
5 **PLANNING AND DEVELOPMENT”?**

6 A. Informed transmission planning and development entails a two-way exchange of
7 information whereby the utility plans are shaped by input from customers, the Commission,
8 and other stakeholders, and, reciprocally, the utility provides sufficiently robust
9 information to facilitate the provision of such input.

10 Under twentieth century transmission planning processes, utilities unilaterally designed
11 and built their networks. This single-party planning approach may have been sufficient
12 during the first 100 years of the electric network’s existence, when customers were less
13 informed about energy systems, load growth remained flat for decades-long stretches,
14 technology was less advanced, and transmission infrastructure was closer to the beginning
15 rather than the end of its lifespan. But we are now in an era of projected unprecedented
16 load growth, increasingly severe weather events, and aging generation and transmission
17 infrastructure.

18 Under twenty-first-century advanced transmission planning processes, transmission
19 planners and utilities continue to serve the role as the principal transmission experts, but
20 they also incorporate two-way flows of information, which include: (1) providing an
21 opportunity for stakeholders and regulators to offer input throughout the planning and
22 development process, (2) taking steps to integrate and respond to such input, and
23 (3) providing meaningful transparency to their regulators and stakeholders so that such
24 input is relevant and actionable. If utilities do not take advantage of opportunities to work
25 alongside the Commission and customers, the planning results will likely be less cost-

lifecycle.”); American Society of Civil Engineers, *Policy Statement 484 - Electricity Generation and Transmission Infrastructure*, Re-adopted by the Board of Direction on July 22, 2023 (“The United States [] has an aging and complex patchwork system for energy transmission. The U.S.’s electric system consists of power generation, transmission lines, and substations that must operate cohesively to power our homes and businesses. Most components of these systems were constructed in the 1950s and 1960s with a 50-year life expectancy, and more than 640,000 miles of high-voltage transmission lines in the lower 48 states’ power grids are at full capacity.”).

1 efficient, leading to increased and unnecessary costs that customers will be required to
2 bear.

3 **Q. DOES THE COMMISSION HAVE THE AUTHORITY TO ORDER GEORGIA**
4 **POWER TO ENGAGE IN COST-EFFECTIVE, PROACTIVE, MULTI-VALUE,**
5 **AND INFORMED TRANSMISSION PLANNING AND DEVELOPMENT?**

6 A. Yes. The Commission's authority to direct Georgia Power to adopt processes that will
7 promote cost-effective, proactive, multi-value, and informed transmission planning and
8 development stems from three sources:

- 9 • The Commission's rate-setting authority over Georgia Power's bundled rates,
10 which include the charges Georgia Power assesses its retail customers to recover
11 the costs associated with Georgia Power's transmission investments, in addition to
12 generation and distribution investments. While the Federal Energy Regulatory
13 Commission ("FERC") has primary authority over the rates, terms, and conditions
14 of transmission service under the Federal Power Act, it has declined to exert
15 jurisdiction over bundled rates for retail service such as those Georgia Power
16 charges its retail customers.²
- 17 • State law directing the Commission to make determinations as to the adequacy of
18 the Integrated Resource Plan ("IRP") and to ensure that the utility's IRP has
19 appropriately addressed numerous matters, including whether "all resources
20 reasonably available to reliably meet future energy service demands [including
21 transmission, which is considered to be a supply-side resource,] are considered by
22 the utility on a fair and consistent basis."³
- 23 • Recent FERC orders clarifying that states have an expanded role in regional and
24 interregional transmission planning and determining cost allocation
25 methodologies.⁴

² See *New York v. FERC*, 535 U.S. 1, 25-26 (2002).

³ Ga. Comp. R. & Regs. § 515-3-4.02.

⁴ See, e.g., *Order Establishing Task Force and Soliciting Nominations*, 175 FERC ¶ 61,224, at P 2 (2021) (discussing the importance of state-federal cooperation on transmission planning and stating that "the area is ripe for greater . . . coordination and cooperation."); *Bldg. for the Future Through Elec. Reg'l Transmission*

1 **II. WITNESS BACKGROUND**

2 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

3 A. I am testifying on behalf of Georgia Interfaith Power & Light and Southface Energy
4 Institute.

5 **Q. PLEASE SUMMARIZE YOUR RELEVANT WORK EXPERIENCE AND**
6 **EDUCATION.**

7 A. In my current position at DGA, I provide expert advice on policies needed to support
8 equitable and cost-effective electric transmission expansion and modernization, to advance
9 transportation and building sector decarbonization, and to increase access to decarbonized
10 energy sources. I also provide organizational management support to certain of our non-
11 profit clients.

12 Prior to joining DGA, I served as the Litigation Supervisor and a Senior Assistant People's
13 Counsel at the District of Columbia Office of the People's Counsel, the utility ratepayer
14 advocate for the District of Columbia. In that role, I practiced before FERC, PJM
15 Interconnection LLC ("PJM"), and the District of Columbia Public Service Commission
16 and supervised the dockets of junior attorneys. My portfolio addressed both wholesale and
17 distribution issues, and included electric transmission and distribution rate cases, gas and
18 electric infrastructure proceedings, and regional market, resource adequacy, and grid
19 modernization policies. Between 2010 and 2018, I was an attorney with the law firm
20 Spiegel & McDiarmid where I practiced energy, telecommunications, and airport law. My
21 energy portfolio included transmission and distribution rate cases, FERC rulemakings,
22 environmental regulations, and regional energy and capacity market rules. I earned my J.D.
23 from the University of Michigan, M.S. in Environmental Policy from Drexel University,
24 and B.A. in Biology and Environmental Studies from Case Western Reserve University.

Plan. & Cost Allocation, Order No. 1920, 89 FR 49280 (June 11, 2024) ("Order No. 1920"), 187 FERC ¶ 61,068, at P 994 (requiring transmission providers to consult with and seek support from relevant state commissions), *order on reh'g & clarification*, Order No. 1920-A, 89 FR 97174 (Dec. 6, 2024) ("Order No. 1920-A"), 189 FERC ¶ 61,126 (2024), *order on reh'g & clarification*, Order No. 1920-B, 191 FERC ¶ 61,026 (2025) ("Order No. 1920-B").

1 **Q. WHAT IS YOUR BUSINESS ADDRESS?**

2 A. 2425 Wilson Blvd., Arlington VA, 22201.

3 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

4 A. Yes. In 2024, I testified in Docket No. 55378 regarding Georgia Power's Updated
5 Integrated Resource Plan on behalf of the Southern Alliance for Clean Energy.

6 **Q. ARE YOU SUBMITTING EXHIBITS ALONG WITH YOUR TESTIMONY?**

7 A. Yes, I am submitting one exhibit, my curriculum vitae, marked Exhibit AP-1.

8 **III. SUMMARY OF FINDINGS AND CONCLUSIONS**

9 **Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.**

10 A. On its face, Georgia Power's proposed ten-year Georgia Integrated Transmission System
11 ("ITS") transmission plan ("Ten-Year Plan") in its 2025 IRP appears to be a significant
12 step forward from the transmission filings that it included in past IRPs and the 2023 interim
13 IRP update—which included minimal, if any, transmission projects. I commend Georgia
14 Power for taking seriously the concerns raised in earlier IRP dockets that investments in
15 the transmission system are needed to support customer service. I also commend Georgia
16 Power for taking to heart the Commission's directives to provide additional transparency
17 in transmission planning⁵ by including more expansive information about some, though
18 not all, of the projects in the Ten-Year Plan.

19 On a deeper dive, however, Georgia Power's Ten-Year Plan continues to reflect reactive
20 planning, raising serious questions as to whether the proposed projects are cost-effective.
21 And because the process used to develop the Ten-Year Plan was not meaningfully informed
22 by stakeholders, it is extremely difficult to independently verify the cost-effectiveness of
23 the plan. Given the scale of transmission investment costs identified in this proceeding that
24 will be borne by customers, it is critical that the Commission ensures Georgia Power's
25 proposal is cost-effective and directs Georgia Power to continue developing its planning

⁵ See Ga. Pub. Serv. Comm'n, *Order Adopting Stipulations*, Docket Nos. 44106 and 44161, at ¶ 11 (2022) ("2022 IRP Order").

processes so they are proactive, reflect multi-value planning methodologies and assumptions, and are informed by Commission and stakeholder input.

In order to resolve these concerns, I offer the following seven recommendations:

(1) The Commission should direct Georgia Power to enhance its transmission planning processes and conduct a proactive and multi-value planning analysis.

(2) The Commission should require Georgia Power to provide a meaningful analysis of alternative solutions and technology choices.

(3) The Commission should require Georgia Power to report on regional and interregional transmission alternatives as part of its IRP and associated filings.

(4) The Commission should require Georgia Power to provide a Southern Company (“Southern”)-wide transmission plan alongside its Georgia-only Ten-Year Plan.

(5) The Commission should direct Georgia Power to establish a Georgia Transmission Advisory Group to inform transmission planning processes.

(6) The Commission should direct Georgia Power to provide additional cost transparency.

(7) The Commission should direct Georgia Power to provide post-event reports after extreme weather events.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS?

A. Yes. Given the monumental changes impacting the energy network, I additionally recommend and encourage the Commission to foster more opportunities to collaborate with commissioners in neighboring states on transmission issues.

IV. BACKGROUND ON TRANSMISSION AND THE STATE OF THE ELECTRIC SYSTEM IN GEORGIA

A. Transmission is an integral component of a well-functioning grid.

Q. PLEASE EXPLAIN THE ROLE OF TRANSMISSION IN PROVIDING SAFE, RELIABLE, AND AFFORDABLE ELECTRIC SERVICE TO GEORGIA POWER CUSTOMERS.

A. Transmission serves multiple roles, including:

- Transmission is an integral component of the state’s electric system, filling the role of the highway that carries the electrons from the facilities where they are generated to large industrial customers or to the lower-voltage distribution lines that connect to Georgians’ homes, schools, businesses, and hospitals.
- Transmission enables economies of scale by facilitating the delivery of lower cost power from larger generating systems to load centers. This was an important concept in the 1950s and 1960s when energy demand was surging around the country and, as a result, transmission networks and larger generators were being developed to meet that demand. It is equally, if not more, important today when all facets of Georgia’s economy depend on reliable and affordable electricity, and we are in an era of significant demand growth projections.
- Transmission supports affordability in that it enables utilities to pool resources and dispatch them more effectively to reduce the total amount of generation needed to serve their systems. By contrast, transmission constraints can reduce the capacity available from existing generation, which in turn increases the utility’s generation procurement requirements to meet peak load.
- Transmission serves an important resilience function by allowing utilities to import power from neighbors, particularly during times of extreme stress where generators within a utility footprint cannot operate at peak performance. Importantly, transmission is resource-agnostic. So long as there is sufficient operating capacity, transmission lines will carry electrons from generators to load regardless of the fuel used to create them.

Conversely, when there is insufficient grid capacity to move lower-cost generation to where demand is located, grid operators must dispatch more expensive generation, which increases costs to customers, or they must curtail service. Although there is no monetary information on the price of congestion in the Southeast, in 2023, customers across the country bore around \$11.5 billion in congestion costs.⁶

⁶ Nathan Shreve, et al., Grid Strategies, 2023 Transmission Congestion Report, 3 (Sept. 2024), https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies_2023-Transmission-Congestion-Report.pdf.

1 In worst-case scenarios, a lack of transmission capacity can lead to rolling blackouts,
2 impacting human health and the larger economy. Georgia Power has done a commendable
3 job of avoiding rolling blackouts to date, but, as I discuss later in my testimony, Georgia
4 Power has skated on the razor's edge on more than one occasion. In at least one of those
5 occasions—during Winter Storm Elliott—customers were subjected to significant price
6 spikes in generation as there were only limited transmission interconnections available to
7 import capacity into the state.

8 **Q. ARE ALL FORMS OF TRANSMISSION EQUALLY BENEFICIAL TO**
9 **CUSTOMERS?**

10 No. Transmission comes in a variety of different voltages and cable technologies. With
11 respect to voltage, every voltage level serves a role within the network, but the highest
12 \$/mile value comes from higher-voltage projects.⁷ The reason for this is that, all things
13 equal, higher-voltage projects have larger carrying capacities and lower line losses than
14 lower-voltage lines. Higher-voltage projects are particularly important when the system
15 would benefit from longer-distance facilities to connect load to generation sources located
16 further away or to strengthen interties with neighboring regions. Additionally, one higher-
17 voltage project could offset the need for multiple lower-voltage projects at a lower total
18 cost.

19 Similarly, the value of a project to customers can change based on the type of wire, or
20 “conductor,” used in the project. Traditional aluminum conductor steel-reinforced
21 (“ACSR”) cable was invented in the early 1900s. While many utilities continue to integrate
22 this century-old technology into their transmission systems, it is not the only option, or
23 even the best option. Indeed, ACSR cables are more subject to line sag, thermal limitations,
24 overloading, and higher energy losses than aluminum conductor steel supported (“ACSS”)
25 cables or the even more advanced aluminum conductor composite core (“ACCC”) cables.⁸

⁷ See, e.g., Midcontinent Indep. Sys. Op., Transmission Cost Estimation Guide for MTEP24 (May 2024), <https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf>.

⁸ See, e.g., Pooya Pravizi, et al., *Evaluating the Mechanical and Thermal Performance of High-Temperature Low Sag (HTLS) Conductors: A Comparative Study of ACCC, ACSS, and ACSR Conductors*, Results in Engineering, June 2025, at 1-2, <https://www.sciencedirect.com/science/article/pii/S2590123025008126>. Although ACSS technology is more advanced than ACSR, it was developed in the 1970s, meaning that it is over 50-years old.

1 Experts have found that “[a]t the national level . . . Advanced Conductors [such as ACCC]
2 can prevent annual transmission losses of approximately 21 million megawatt-hours
3 (MWh),” and “can double the power density on paths using existing structures, which can
4 be valuable during system emergencies when system operators desperately need capacity
5 to keep the lights on.”⁹

6 **Q. PLEASE EXPLAIN HOW TRANSMISSION DEVELOPMENT COSTS ARE**
7 **PASSED ONTO CONSUMERS IN THEIR ENERGY BILLS?**

8 When transmission lines go into service, Georgia Power will seek Commission permission
9 in a rate case to include the costs of the projects in retail rates. Transmission is one of
10 multiple network components in rates—the other two major components are costs
11 associated with: (1) power generation and (2) local delivery through the distribution
12 network. The entire cost of the transmission project is not reflected immediately in rates,
13 rather the development costs are recovered over a multi-decade period on a levelized basis.
14 Operational costs associated with the transmission lines are recovered on an ongoing basis.

15 **Q. IF THE COMPANY BUILDS MORE TRANSMISSION, WON’T THAT CAUSE**
16 **CUSTOMER BILLS TO INCREASE?**

17 A. It depends. Well-planned transmission effectively pays for itself, but if transmission is
18 planned poorly, rates could rise, particularly if the projects are not designed to access lower
19 cost generation resources or do not address congestion. Poor planning could also cause
20 rates to rise if transmission projects are not designed to sufficiently meet additional
21 capacity needs, thereby requiring additional transmission upgrades or expansion projects
22 in the relatively near future. Moreover, if projects utilize older technologies that cannot
23 withstand or function fully under extreme weather conditions such as hurricane-force
24 winds, high heat, or extreme cold, then customers will incur additional social and monetary
25 costs due to unreliable service.

Jay Caspary and Jesse Schneider, Advanced Conductors on Existing Transmission Corridors to Accelerate Low Cost Decarbonization 6 (Mar. 2022) (“Advanced Conductors Report”), <https://wiresgroup.com/advanced-conductors-on-existing-transmission-corridors-to-accelerate-low-cost-decarbonization/#:~:text=The%20report%20finds%20that%20reconductoring%20and%20rebuilding%20existing,quickly%20and%20more%20cost-effectively%20than%20new%2C%20large-scale%20transmission.>

⁹ Advanced Conductors Report at 6-7, 18.

1 Studies show, however, that if transmission is planned well, the associated costs are more
2 than offset by the reductions in *generation* costs that come from being able to tap into
3 cheaper energy sources. For example, a 2020 report from Americans for a Clean Energy
4 Grid determined that “transmission expansion and the resulting growth in wind and solar
5 generation causes large reductions in consumer electric bills[.]”¹⁰ The report calculated the
6 savings for an average household would be approximately \$300 per year based on
7 electricity consumption levels in 2020.¹¹

8 Similarly, the Department of Energy’s 2024 National Transmission Planning Study found
9 that “[a]ccelerated transmission expansion leads to national electricity system cost savings
10 of \$270 to \$490 billion through 2050.”¹² The Transmission Planning Study further found
11 that “[i]ncremental investments in transmission are more than compensated for by reduced
12 electricity system costs for fuel, generation and storage capacity, and other costs.
13 Approximately \$1.60 to \$1.80 is saved for every dollar spent on transmission.”¹³ The
14 Department of Energy’s National Transmission Needs Study additionally found that a
15 significant portion of savings comes from alleviating transmission congestion during
16 “[e]xtreme conditions and high-value periods,” noting that “50% of transmission
17 congestion value com[es] from only 5% of hours.”¹⁴

18 In other words, well-planned transmission effectively pays for itself.

19 **B. Additional transmission is needed to serve Georgia Power customers.**

20 **Q. WHAT IS THE MAKEUP OF GEORGIA POWER’S CURRENT TRANSMISSION**
21 **FOOTPRINT?**

22 A. Georgia Power’s existing transmission system is largely comprised of lower-capacity lines.
23 According to Georgia Power’s 2025 IRP Technical Appendix Volume Three, less than

¹⁰ Christopher Clack, et al., Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S. 9 (2020), <https://cleanenergygrid.org/portfolio/consumer-employment-and-environmental-benefits-of-transmission-expansion-in-the-eastern-u-s/>.

¹¹ *Id.*

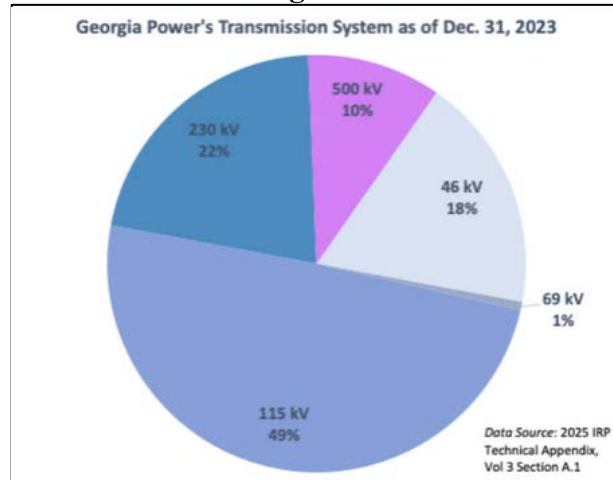
¹² U.S. Dep’t of Energy, National Transmission Planning Study, Executive Summary 2 (2024) (“Transmission Planning Study”), <https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-ExecutiveSummary.pdf>.

¹³ *Id.*

¹⁴ U.S. Dep’t of Energy, National Transmission Needs Study v (2023) (“National Transmission Needs Study”), <https://www.energy.gov/gdo/national-transmission-needs-study>.

one-third of Georgia Power’s transmission network is greater than 230 kV or above and only ten percent of the total lines are high-voltage 500kV or above.¹⁵ See Figure 1 below:

Figure 1



Q. WHAT LEVEL OF INTERCONNECTION DOES GEORGIA POWER HAVE WITH NEIGHBORING UTILITIES?

A. The Georgia Power footprint is located in the Southern balancing authority area (“BAA”), also referred to as “SOCO.” According to the FERC, North American Electric Reliability Corporation (“NERC”), and Regional Staff Entity Report on Winter Storm Elliott, the Southern BAA had 55 total alternating current (“AC”) transmission ties to other core BAAs in the Eastern Interconnection as of 2022.¹⁶ These include:

BAA	No. of Interconnections
Florida	26
Tennessee Valley Authority (“TVA”)	12
Midcontinent Independent System Operator (“MISO”)	9
Dominion Energy South Carolina (“DESC”)	5
South Carolina Public Service Authority (“Santee Cooper”)	2
Duke Energy	1

¹⁵ Georgia Power, 2025 Integrated Resource Plan, Tech. App’x 3, at 1.

¹⁶ FERC, NERC, and Regional Staff Entity Report, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott at 29 (Oct. 2023) (“FERC-NERC Elliott Report”) (Figure 12 provides a breakdown of AC and DC lines by Balancing Authority). Georgia Power’s response to Data Request No. STF-PIA-1-2 provides a current list of interconnections.

1
2 **Q. WHY DOES THE EXISTING DESIGN OF GEORGIA POWER'S**
3 **TRANSMISSION SYSTEM MATTER?**

4 A. Georgia Power, like utilities in other areas of the country, is facing three main risks to its
5 existing network: extreme weather, aging infrastructure, and projected rapid growth in
6 energy demands. Continuing to operate a primarily low-voltage system will be both an
7 expensive and unreliable way to meet these challenges. To avoid exacerbating reliability
8 risks and mitigate adverse economic impacts, Georgia Power must both: (1) expand its
9 system by adding additional transmission facilities and (2) modernize its system by
10 (a) upgrading or reconductoring existing lines with advanced transmission technologies to
11 maximize the capacity of the current system and (b) using advanced transmission
12 technologies on new projects to build "smart from the start."

13 **Q. EARLIER YOU DISCUSSED THE VALUE OF HIGH-VOLTAGE**
14 **TRANSMISSION LINES. ARE YOU RECOMMENDING THAT THE**
15 **COMPANY'S PLAN SHOULD INCLUDE ONLY HIGH VOLTAGE LINES?**

16 A. No. Lower-voltage lines are part of the building blocks of a strong network and may be
17 needed on the system. But the order in which projects are evaluated can make a substantial
18 difference to the ultimate recommendations. I recommend that Georgia Power first
19 evaluate high-capacity solutions, such as 500 kV or high-voltage direct current ("HVDC")
20 lines, because they provide the greatest value to customers. Any remaining gaps could then
21 be filled in with lower-voltage solutions as needed.

22 **Q. WHY SHOULD GEORGIA POWER START WITH HIGH-VOLTAGE LINES?**

23 A. Higher-capacity projects can both obviate the need for other lower-voltage solutions and
24 provide opportunities for future growth.

25 **Q. CAN YOU PROVIDE AN EXAMPLE WHERE PRIORITIZING A HIGH-**
26 **CAPACITY PROJECT OBTAINED THE NEED FOR OTHER LOWER-**
27 **VOLTAGE SOLUTIONS?**

28 A. Yes. Data Request No. STF-GS-1-6 sought information about ARLINGTON PRIMARY
29 - HWY45/234 RECONDUCTOR 115KV (F.K.A. ARLINGTON PRIMARY - DAWSON

1 PRIMARY 115KV), which is listed as “no longer required” in the Ten-Year Plan. In
2 response to the request, Georgia Power explains that the project “is listed as ‘no longer
3 required’ because it was replaced by a strategic transmission project, Farley (APC) –
4 Tazewell 500kV Line (TEAMS 21063), that solved the system overloads driving the
5 aforementioned project and provides numerous other capacity benefits to the system.”

6 **Q. ARE THERE ANY INSTANCES WHERE GEORGIA POWER APPEARS TO BE**
7 **FOLLOWING YOUR RECOMMENDATION TO PRIORITIZE HIGH VOLTAGE**
8 **LINES IN THE PLANNING PROCESS?**

9 A. Yes. Georgia Power’s response to Data Request No. STF DEA-2-1 seems to indicate that
10 Georgia Power first identifies “500kV projects that would alleviate 500kV constraints
11 along with resolving any identified 230kV or 115kV constraints” before turning to 230 kV
12 and 115 kV solutions.

13 **Q. WHAT IS THE DIFFERENCE BETWEEN WHAT GEORGIA POWER IS**
14 **CURRENTLY DOING AND YOUR SUGGESTION?**

15 A. The quoted portion of the response to Data Request No. STF DEA-2-1 refers to Georgia
16 Power’s process for “identifying the *strategic projects* shown in Table 11.3 of the
17 Integrated Resource Plan [] Main Document during the version 2 analyses of the
18 transmission planning process.” (emphasis added). As Georgia Power explains in its
19 response to Data Request No. STF-GS-2-6, the strategic project “studies involve distinct
20 scenarios that are not evaluated as part of the standard ten-year planning process.”
21 Additionally, the prioritization discussed in response to Data Request No. STF DEA-2-1
22 is limited to constraints that Georgia Power defines as “500 kV” constraints.

23 The process that Georgia Power uses for developing solutions to the rest of its Ten-Year
24 Plan—which includes its version 1 analysis, non-strategic projects, and constraints that
25 Georgia Power defines as 230 kV or less—is outlined in Section 6 of Technical
26 Appendix Volume Three and does not prioritize review of 500 kV solutions. I am
27 recommending that potential high-voltage solutions be reviewed first in *all* scenarios to
28 streamline the need for multiple—and potentially more expensive in the aggregate—low-
29 voltage solutions.

1 1. Impact of Extreme Weather

2 **Q. PLEASE EXPLAIN WHY THE TRANSMISSION NETWORK SHOULD BE**
3 **EXPANDED/MODERNIZED TO PROTECT AGAINST EXTREME WEATHER.**

4 A. During times of extreme weather, the energy system within one utility's footprint may not
5 be sufficient to meet its customers' needs. Generators may need to shut down (particularly
6 in high heat, fire, or extreme cold conditions) and fuel may not be available, all while
7 demand may be peaking as customers seek to heat or cool their living and working spaces.
8 Additionally, older transmission technologies may face physical and operational
9 challenges due to high wind or extreme temperature conditions.

10 Strong, interconnected, and modernized transmission means greater flexibility to import
11 power from outside the affected area, particularly from areas that may not be experiencing
12 the same weather patterns or are not as hard hit.

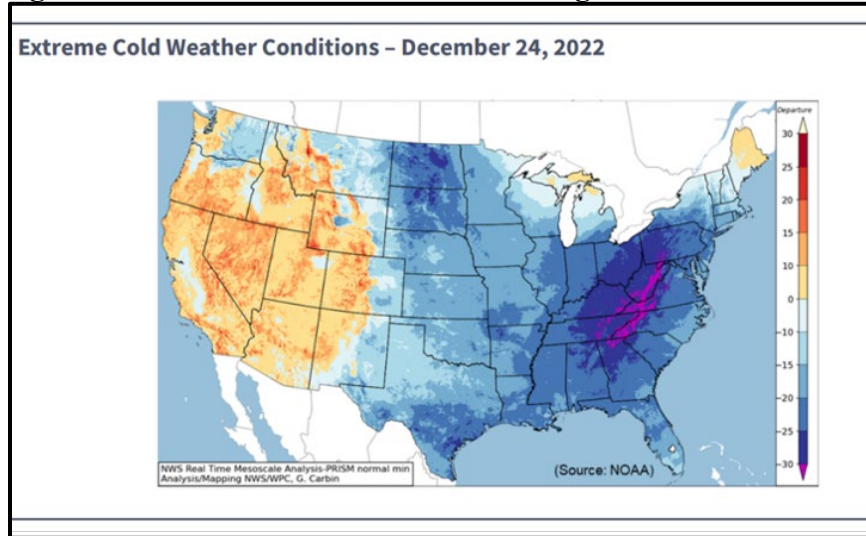
13 **Q. CAN YOU SHARE ANY EXAMPLES OF RECENT EXTREME WEATHER**
14 **EVENTS THAT IMPACTED GEORGIA POWER?**

15 A. Yes, there have been several recent storms that impacted Georgia Power's system,
16 including most recently Hurricane Helene and Winter Storm Elliott.¹⁷ Winter Storm Elliott,
17 which hit right around the Christmas holiday in 2022, "had the largest footprint of any
18 [extreme weather event] examined in a joint FERC-NERC-Regional Entity inquiry...the
19 extreme cold weather covered most of the eastern half of the lower 48 United States."¹⁸
20 (See Figure 2).

¹⁷ A few years earlier, in 2018, Georgia was impacted by Hurricane Michael which "resulted in outages for up to 1.7 million electricity customers across six states," after making landfall in the Florida panhandle and travelling through Alabama, Georgia, North Carolina, South Carolina, and Virginia. Energy Info. Admin., *Hurricane Michael caused 1.7 million electricity outages in the Southeast United States* (Oct. 22, 2018), <https://www.eia.gov/todayinenergy/detail.php?id=37332>.

¹⁸ FERC-NERC Elliott Report at 22.

Figure 2: Cold Weather Conditions During Winter Storm Elliott



(Source: FERC-NERC Elliott Report at Figure 8, Page 23).

Q. WHAT WAS THE EFFECT OF WINTER STORM ELLIOTT ON UTILITIES IN THE SOUTHEAST?

A. During Winter Storm Elliott, several major utilities in the Southeast were forced to implement rolling blackouts within their systems, including Duke Energy, TVA, and Louisville Gas & Electric/Kentucky Utilities (“LG&E/KU”).¹⁹ As per the FERC-NERC report:

virtually all of the [balancing authorities/reliability coordinators] saw generation lost or derated due to Natural Gas Fuel Issues on December 23 and 24. SPP, TVA, LG&E/KU, and VACAR-South RC all reported gaining awareness on December 23 or 24 that generating units were struggling to find adequate natural gas supply or that pipelines were struggling or unable to maintain adequate pressure at certain locations.²⁰

¹⁹ Energy Ventures Analysis, Operation of the U.S. Power Generation Fleet During Winter Storm Elliott 17, (Feb. 2023); see also, Duke Energy, *Duke Energy updates North Carolina Utilities Commission on Winter Storm Elliott Emergency Outage Event* (Jan. 3, 2023), <https://news.duke-energy.com/releases/duke-energy-updates-north-carolina-utilities-commission-on-winter-storm-elliott-emergency-outage-event>; Tennessee Valley Authority, *TVA Accepts Responsibility, Starts Full Review* (Dec. 28, 2022), <https://www.tva.com/news-media/releases/tva-accepts-responsibility-starts-full-review>; Louisville Public Media, LG&E/KU underestimated energy demand ahead of winter storm Elliott (Jan. 26, 2023), <https://www.lpm.org/news/2023-01-26/lg-e-ku-underestimated-energy-demand-ahead-of-winter-storm-elliott>.

²⁰ FERC-NERC Elliott Report at 49.

1 In the Southern territory, generation also went down, but its utility operating companies—
2 including Georgia Power—were able to import sufficient power from neighboring utilities,
3 mainly from Florida, to stave off large-scale blackouts.

4 **Q. CAN YOU EXPLAIN EXACTLY HOW TRANSMISSION PREVENTED**
5 **OUTAGES IN SOUTHERN’S TERRITORY?**

6 A. For Georgia specifically, power outages in the Southern BAA began at midnight on
7 December 23, 2022.²¹ During the first two hours of December 24, Southern forced 500
8 MW of gas- and oil- generating unit capacity offline. Over the following four hours,
9 Southern forced an additional 890 MW of gas/combined cycle generating capacity offline.
10 Between 12:00am to 6:00am on December 24, Southern had a total of 1,390 MW in
11 incremental unplanned outages.²²

12 Initially, Southern was able to provide emergency energy to support other BAAs, such as
13 TVA, but by the early evening of December 23, Southern began curtailing its energy
14 exports to TVA to deal with its own energy emergencies.²³ On December 24 at 2:00am
15 Southern declared an Energy Emergency Alert (“EEA”) 1 given increasing system loads
16 and unplanned generation outages. By 6:25am, Southern declared an EEA 2 due to
17 additional unplanned generation outages, declining operating reserves, and expected load
18 increase, leading to a request for emergency energy from its neighbor, Florida Power &
19 Light (“FP&L”). At 7 am, FP&L sent **1,000 MW of emergency energy** into the Southern
20 BAA.²⁴ PJM reports that MISO also provided **100 MW of emergency power** to the
21 Southern BAA during Winter Storm Elliot.²⁵

²¹ *Id.* at 48.

²² *Id.*

²³ *Id.* at 63-64.

²⁴ *Id.* at 64, 69, 72.

²⁵ PJM Interconnection, L.L.C., Winter Storm Elliott: Event Analysis and Recommendation Report 19 (July 17, 2023).

1 **Q. ARE THERE ANY OTHER STUDIES THAT DEMONSTRATE HOW**
2 **GENERATION LOSS IMPACTED GEORGIA DURING WINTER STORM**
3 **ELLIOTT?**

4 A. Yes. Telos Energy recently conducted a study using data provided by Georgia Power,
5 which explains how the Company experienced concerning drops in generation capacity
6 during the EEA 1 and EEA 2 periods. On December 24, 2022, 228 plants in the territory
7 either had “known outages reported by GPC” or “substantial deviations,” or “did not
8 generate at all during the event.”²⁶ As the report notes:

9 Not all the unavailability exhibited by these plants can be
10 attributed to forced outages without additional information. But
11 the fact remains that these plants either had generators on some
12 type of outage or were experiencing derates due to fuel supply
13 availability during the emergency window.²⁷

14 **Q. PLEASE DESCRIBE WHAT HAPPENED DURING HURRICANE HELENE.**

15 A. Hurricane Helene was the second deadliest hurricane to strike the continental U.S. in 50
16 years. In September 2024, Helene made landfall in Florida before entering Georgia as a
17 Category 1 storm. At peak, 1.1 million Georgia customers (22%) experienced outages.²⁸
18 According to the limited information available publicly, the storm impacted over 1,200
19 spans of transmission lines, and “[i]n total, teams replaced 345 transmission structures and
20 restored over 230 facilities, including around 200 transmission lines. In the hardest hit
21 areas, around 50% of transmission lines were impacted.”²⁹

22 **Q. HOW DID GEORGIA POWER’S GENERATION RESOURCES AND**
23 **TRANSMISSION SYSTEM PERFORM DURING HELENE?**

24 A. As there is not publicly available information on this issue, it is unclear.

²⁶ Telos Energy, Winter Storm Elliott: An Independent Review of Southern Company’s Performance During the Historic Events of December 22-25, 2022 7 (May 2025), https://drive.google.com/file/d/1N8W60AN1jbnFPmFXCaKOV_N-TCFeKNmo/view (“Telos Report”); *see also* Response to Data Request No. HR-1-1, Docket No. 55378 (noting multiple reasons, in addition to fuel unavailability, that generators may not be able to operate).

²⁷ Telos Report at 7.

²⁸ Dave Krueger and Rhiannon Gomes, SERC Reliability Corporation Ex Parte Briefing to The South Carolina Public Service Commission and Office of Regulatory Staff 11 (Jan. 29, 2025).

²⁹ Response to Data Request No. STF-DEA-2-6, Attachment.

1 **Q. HAS GEORGIA POWER TAKEN ANY STEPS TO IMPROVE RESILIENCY**
2 **AFTER HURRICANE HELENE?**

3 A. In a data request, Georgia Power was asked whether it had “assessed resiliency
4 improvements in response to Hurricane Helene,” and, if so, what it had considered.³⁰ In
5 response, Georgia Power provided an attachment that included a post-storm summary that
6 primarily detailed the extent of storm damage and utility crew response efforts.³¹ However,
7 neither the data response nor the attachment discusses any proactive steps Georgia Power
8 has considered to improve resiliency during future storms like Helene or which, if any,
9 projects in the Ten-Year Plan address this issue.

10 **Q. HAS GEORGIA POWER COMMENTED ON THE ROLE THAT**
11 **TRANSMISSION TIES PLAYED IN ITS RESPONSE TO EXTREME WEATHER**
12 **EVENTS?**

13 A. Yes. During this IRP proceeding, Company witness, Michael Robinson, Vice President for
14 Grid Transformation, acknowledged that interregional transfer capability facilitated power
15 imports, but he caveated that statement with the following comment:

16 I would say we have that reliability today . . . and that’s been
17 evidenced through Elliott, through other winter storms where . .
18 . we’ve been able to weather through those where our
19 neighboring utilities have not necessarily been able to do that.³²

20 Mr. Robinson also stated the company does not “see a need for increased reliability,” but
21 “if there were a need, we would look at the economics of that and what made sense for our
22 customers and the customers of our neighboring utilities.”³³

23 **Q. DO YOU AGREE WITH MR. ROBINSON’S CLAIM THAT THERE IS NO**
24 **“NEED FOR INCREASED RELIABILITY” OR ADDITIONAL TRANSMISSION**

³⁰ Data Request No. STF-DEA-2-6.

³¹ Response to Data Request No. STF-DEA-2-6, Attachment.

³² Tr.225:5-10 (March 25, 2025).

³³ *Id.* at 446:11-13.

1 **TIES WITH NEIGHBORS GIVEN THAT GEORGIA POWER WAS ABLE TO**
2 **AVOID ROLLING BLACKOUTS IN BOTH EVENTS?**

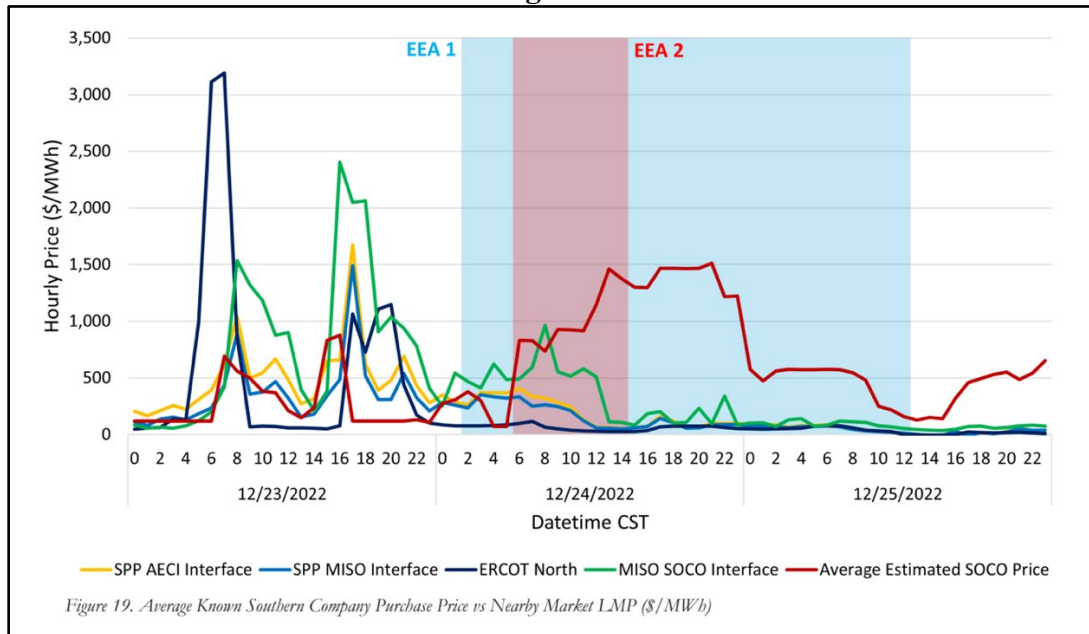
3 A. No. Although it is true that in both instances, Georgia customers were spared the rolling
4 blackouts that affected neighboring states, the system was running on a razor's edge in both
5 instances. Had it not been for energy imports from Florida, the generation outages could
6 have been much worse and could have led to rolling blackouts. And those imports came at
7 a heavy price for customers. As Georgia Power Witness Looney mentioned at the hearing:
8 “[e]ven in the events that may not be quite that severe, we've seen – the only opportunity
9 is to purchase power at extremely high prices: \$2,000 a megawatt hour, that ballpark, and
10 so it's not something you want to rely on, on a frequent basis.”³⁴

11 Mr. Looney's statement failed to explain that prices were that high, in part, because
12 Georgia Power has limited interconnections with other BAAs. The Telos Report provides
13 an analysis of pricing at the interfaces between Southern and other BAAs during Elliott,
14 and includes a chart, provided below in Figure 3, which shows that on December 24 and
15 25, the two days with energy emergency alerts where power was most needed to serve
16 Georgia customers, “prices in ERCOT, SPP, and MISO (at the Southern Company
17 interface) were considerably lower than GPC purchase prices [], when generation weighted
18 known prices averaged over \$1,000/MWh.”³⁵ (*Note: The blue band depicts the EEA 1 time
19 period and the red band depicts EEA 2 time period).*

³⁴ *Id.* at 448:18-23.

³⁵ Telos Report at 21.

Figure 3



If Georgia Power were to expand its transmission connections to neighboring systems, better integrating itself into a larger grid—particularly one that is sized bigger than any possible storm—it could greatly mitigate the risk to customers of future storms.

Q. ARE THERE ANY STUDIES THAT ANALYZE HOW MANY ADDITIONAL INTERCONNECTIONS ARE NEEDED?

A. Yes. There are several findings in this regard, though they are presented in terms of the amount of power neighboring regions should be able to transmit to each other, known as “interregional transfer capability,” rather than in terms of a specific number of lines.

For example, NERC, at the direction of the U.S. Congress, recently published an interregional transfer capability reliability analysis that found that interregional transfer capabilities were “relatively lower” in the Southeast.³⁶ The report also evaluated “prudent additions” to the U.S. transmission system that would “mitigate grid reliability risks under especially challenging circumstances.”³⁷ NERC selected 12 past weather conditions and modeled what would happen if those conditions repeated themselves in 2033; in every case,

³⁶ NERC, Interregional Transfer Capability Study (ITCS) Strengthening Reliability Through the Energy Transformation 13 (2024) (“NERC ITCS Study”).

³⁷ *Id.* at xiv.

the report identified “potential for energy deficiency”³⁸ and recommended adding additional transfer capabilities. (See Figure 4).

Figure 4

Executive Summary

Table ES.1: Recommended Prudent Additions Detail

Transmission Planning Region	Weather Years (WY) / Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
ERCOT	Winter Storm Uri (WY2021) and nine other events	135	18,926	14,100	Front Range (5,700) MISO-S (4,300) SPP-S (4,100)
MISO-E	WY2020 Heat Wave and two other events	58	5,715	3,000	MISO-W (2,000) PJM-W (1,000)
New York	WY2023 Heat Wave and seven other events	52	3,729	3,700	PJM-E (1,800) Québec (1,900)
SPP-S	Winter Storm Uri (WY2021)	34	4,137	3,700	Front Range (1,200) ERCOT (800) MISO-W (1,700)
PJM-S	Winter Storm Elliott (WY2022)	20	4,147	2,800	PJM-E (2,800)
California North	WY2022 Heat Wave	17	3,211	1,100	Wasatch Front (1,100)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
New England	WY2012 Heat Wave and two other events	5	984	700	Québec (400) Maritimes (300)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT (300) SERC-SE (300)
TOTAL				35,000	

Increasing Energy Deficiency Hours

(Credit: NERC ITCS Study at 47).

In the SERC Reliability Corporation territory, which includes the Southern footprint, NERC recommends an additional 4,100 MW of transfer capability to prevent serious problems. Within the sub-footprint of SERC-SE, which is specific to the Southern footprint, NERC recommends 2,200 MW of additional transfer capacity.³⁹ NERC’s recommendations are based on Winter Storm Elliott. As such, contrary to Georgia Power’s assertions at the hearing, even though Georgia Power avoided widespread disruption during Winter Storm Elliott, that is no guarantee its system will withstand future storms.

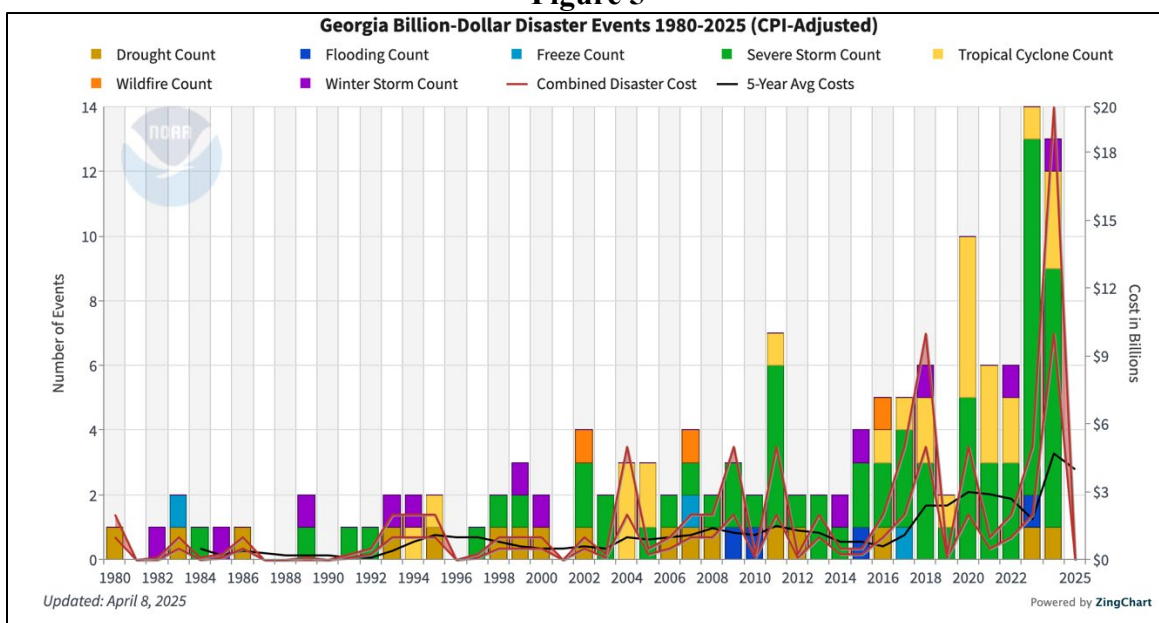
³⁸ *Id.* at 44-45.

³⁹ *Id.* at 47.

1 **Q. BECAUSE TRANSMISSION PROJECTS REQUIRE SIGNIFICANT CAPITAL,**
2 **WOULDN'T IT BE UNECONOMIC TO INVEST IN TRANSMISSION FOR**
3 **ONE-OFF EVENTS?**

4 A. No. As a primary matter, extreme weather events are increasing in frequency; they are no
5 longer “one-off” events. As shown below in Figure 5, the number and cost impacts of
6 billion-dollar disaster events in Georgia have significantly increased since 1980, the
7 starting year of the National Oceanic and Atmospheric Administration (“NOAA”) data
8 reporting.

9 **Figure 5**



(Credit: NOAA, National Centers for Environmental Info., U.S. Billion-Dollar Weather and Climate Disasters: *Georgia*, <https://www.ncei.noaa.gov/access/billions/> (last visited Apr. 30, 2025)).

10 In 2024, alone, the U.S. experienced 27 severe weather events that cost \$1 billion or more
11 in damages, collectively totaling \$185 billion.⁴⁰ Nearly half of those events (thirteen)
12 impacted Georgia, resulting in greater damage costs than any previous year recorded in the
13 data.⁴¹

14 The greater the potential for extreme weather, the more important it is for Georgia Power
15 to build transmission infrastructure to access energy imports to mitigate that risk.

⁴⁰ NOAA, National Centers for Environmental Information, U.S. Billion-Dollar Weather and Climate Disasters, <https://www.ncei.noaa.gov/access/billions/> (last visited Apr. 30, 2024).

⁴¹ *Id.*

1 **Q. IS THERE ANY OTHER JUSTIFICATION FOR EXPANDING AND**
2 **MODERNIZING THE SYSTEM TO ADDRESS WEATHER EVENTS?**

3 A. Yes, it is important to do so to temper overall costs to customers. Studies show that in some
4 instances the costs of building high-capacity transmission are more than outweighed by the
5 benefits those high-capacity transmission facilities bring during a few small high-impact
6 events. For example, researchers that reviewed the impact of transmission during Winter
7 Storm Elliott and Winter Storm Uri—which hit Texas in 2021—found that, had there been
8 adequate transmission connections between Texas and the Southeast, the “modest
9 investments to increase power flows” that could have saved lives during Winter Storm Uri
10 *also* could have provided reverse power flows during Winter Storm Elliott, and over the
11 course of the two events provided close to \$2 billion in value.⁴²

12 Similarly, a 2022 Energy Systems Integration Group report on multi-value transmission
13 planning highlights the relatively low cost of building out transmission to mitigate the
14 impacts of climate events compared to the high-cost implications of said climate events to
15 utility customers.⁴³ The analysis projects a potential 2 GW HVDC interregional line
16 between ERCOT and Southern could “avert \$2.7 billion of unserved energy over 30 years
17 depending on the loss of load expectation.”⁴⁴

18 **2. Impacts of Load Growth**

19 **Q. IS EXTREME WEATHER THE ONLY REASON THAT GEORGIA POWER**
20 **SHOULD BE INVESTING IN EXPANDING AND MODERNIZING ITS**
21 **TRANSMISSION SYSTEM?**

22 A. No. Projected surging energy demand is putting new pressures on the energy system in the
23 region. As Georgia Power explains “Georgia Power continues to see positive economic

⁴² Grid Strategies, The Value of Transmission During Winter Storm Elliott 7 (Feb. 2023), <https://acore.org/wp-content/uploads/2023/02/ACORE-The-Value-of-Transmission-During-Winter-Storm-Elliott.pdf> (finding that a one GW transmission line between the Electric Reliability Council of Texas (“ERCOT”) and TVA would have provided nearly \$95 million in value, mostly to TVA customers. That adds to the nearly \$1 billion in value that line, flowing in the other direction, would have provided Texans suffering through outages during Winter Storm Uri in February 2021).

⁴³ Energy Systems Integration Group, Multi-Value Transmission Planning for a Clean Energy Future 55 (June 2022), <https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf>.

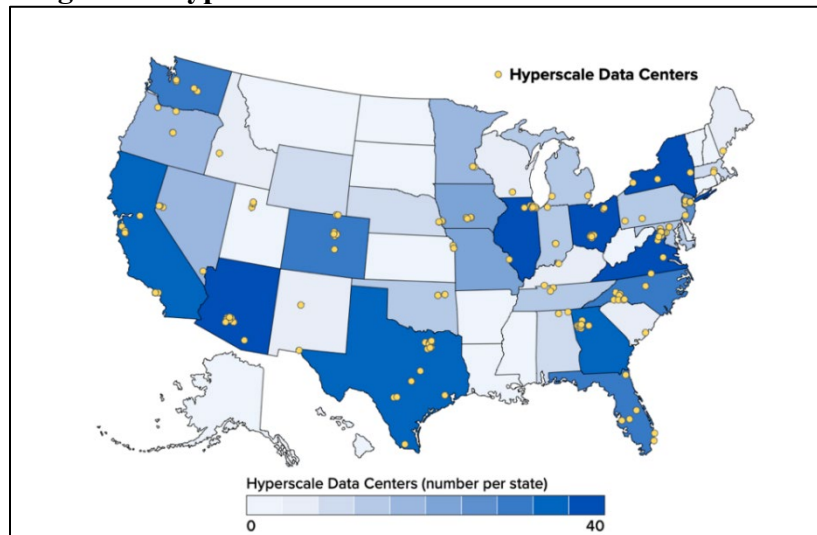
⁴⁴ *Id.*

development trends throughout the state,” and its risk-adjusted load forecast for winter 2024/2025 through winter 2030/2031 includes approximately 8,200 MW of load growth—a jump of more the 2,200 MW since the load growth projections included for this same time period in the 2023 IRP Update.⁴⁵

Q. IS GEORGIA POWER THE ONLY UTILITY PROJECTING LARGE LOAD GROWTH?

A. No. After two decades of mostly flat load growth, national forecasts are predicting an average of three percent annual growth for each year over the next five years.⁴⁶ The majority of that projected growth is attributable to data center load, which is concentrated in a few regions as shown in Figure 6 below:

Figure 6: Hyperscale Data Center Distribution as of 2022



(Credit: EPRI, Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption 9 (May 2024)(“EPRI Report”).

Q. WHAT IS THE IMPACT OF THE GROWTH PREDICTIONS?

A. Forecasters have estimated that while the three percent growth might seem small, “it would mean **six times** the planning and construction of new generation and transmission capacity.”⁴⁷

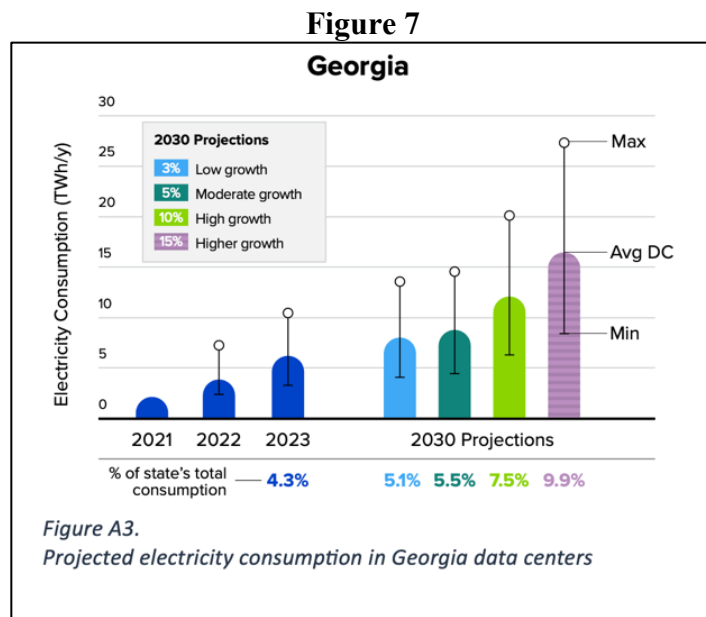
⁴⁵ Georgia Power, 2025 Integrated Resource Plan at 1.

⁴⁶ John Wilson, et al., Grid Strategies, Strategic Industries Surging: Driving US Power Demand slide 5 (Dec. 2024), <https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf> (“Grid Strategies Demand Report”).

⁴⁷ *Id.* (emphasis added).

1 **Q. IS THIS GROWTH GUARANTEED?**

2 A. No. Much is unknown about how much growth will materialize, and, if it does, when it
3 will materialize. Nationwide estimates of data center demand vary widely, from
4 approximately 10 to 65 GW through 2029.⁴⁸ With respect to Georgia, specifically, the
5 EPRI report estimates between 5.1-9.9% increases in load growth by 2030 compared to
6 2021. (See Figure 7).



(Credit: EPRI Report at 24).

8 **Q. WITH SO MUCH UNCERTAINTY, HOW SHOULD GEORGIA POWER**
9 **APPROACH SYSTEM EXPANSION AND MODERNIZATION?**

10 A. I address this issue further in my testimony under Section V.A, but it is important to note
11 here that uncertainty is one of the main reasons that Georgia Power should adopt proactive
12 multi-value planning. By examining multiple load growth scenarios, and multiple system
13 needs, Georgia Power will be better positioned to determine which solutions are “no
14 regrets” solutions and whether there are opportunities to right-size projects.

⁴⁸ *Id.* at slide 10.

1 Based on Georgia Power's response to Data Request No. STF-DEA-6-1,⁴⁹ a sizeable
2 number of the proposed transmission projects in the Ten-Year Plan are aimed at serving
3 projected load growth. Because Georgia Power did not conduct a multi-value planning
4 process, it is not clear that these projects are cost-effective or needed if load does not
5 materialize in the quantities predicted. Moreover, there is no evaluation or showing that
6 these projects will benefit non-large load customers.

7 3. Impacts of Aging Infrastructure

8 **Q. ARE THERE ANY OTHER FACTORS THAT ARE DRIVING THE NEED FOR**
9 **TRANSMISSION EXPANSION AND MODERNIZATION?**

10 A. Yes. Infrastructure age can play a role in reliability of the system. Across the nation,
11 transmission infrastructure is aging. A recent report card from the American Society of
12 Civil Engineers rated the nation's energy infrastructure at a D+, finding that "70% of power
13 transformers are 25 years or older, 60% of circuit breakers are 30 years or older, and 70%
14 of transmission lines are 25 years or older."⁵⁰ There is no data specific to Southern, or
15 Georgia Power in particular, about the age of their transmission lines, but they are likely
16 of a similar, if not older, vintage, than other parts of the nation. The question for the
17 Commission to ask is whether the upgrades Georgia Power has proposed in the Ten-Year
18 Plan are the most cost-effective replacement alternatives.

19 **Q. IS THERE ANY OTHER INFRASTRUCTURE THAT IS AGING?**

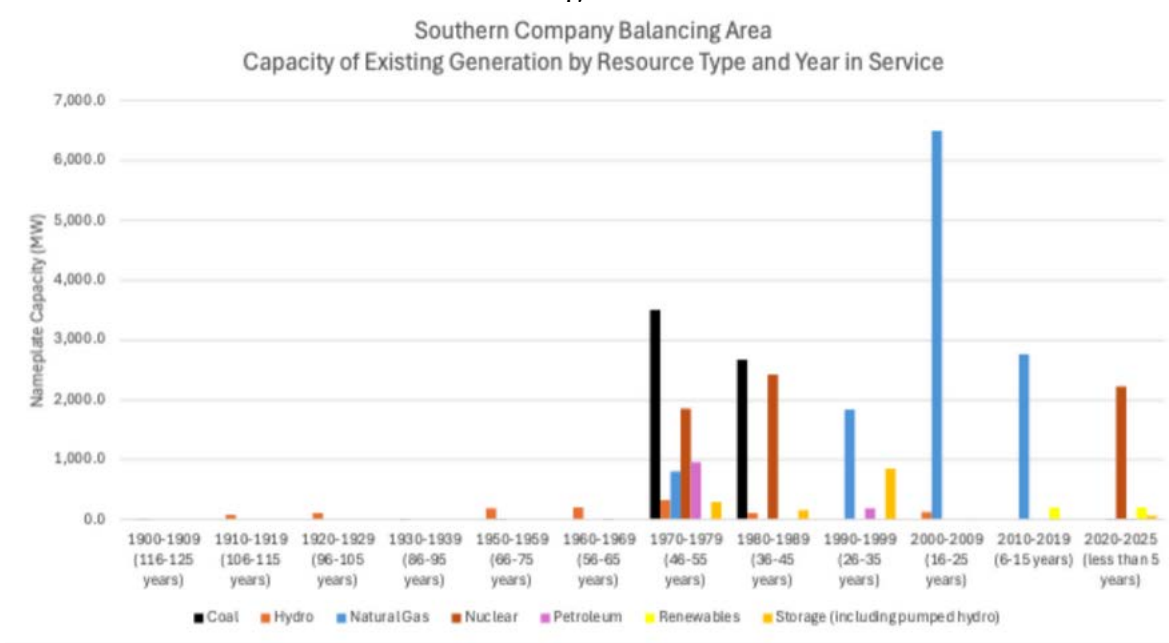
20 A. Yes. The generation infrastructure that serves Georgia Power customers is also aging.
21 Figure 8 below provides a breakdown by generating type and year in service of the existing
22 generation capacity across the Southern BAA, which includes generation located within
23 the Georgia Power footprint and resources within the larger Southern footprint that Georgia
24 Power purchases to serve customers.

⁴⁹ Explaining that there are 208 total projects in the Ten-Year Plan, twenty (20) of which are directly associated with serving large customer loads and twenty-one (21) of which are directly associated with serving Customer Choice Loads. Georgia Power's numbers may be undercounting the transmission projects that are being driven primarily by large load growth.

⁵⁰ American Society of Civil Engineers, *2025 Report Card for America's Infrastructure: Energy*, at 76 (2025), <https://infrastructurereportcard.org/wp-content/uploads/2025/03/Full-Report-2025-Natl-IRC-WEB.pdf>.

1

Figure 8



(Data Source: Energy Info. Admin., *Form 860 Monthly Update* (Mar. 2024), <https://www.eia.gov/electricity/data/cia860m/>).

2 Nearly 50% of the operational capacity in the Southern footprint was built over 35 years
 3 ago, including the still-operational coal plants. Even if the region were not facing projected
 4 significant load growth, advanced planning would be needed to address the transition from
 5 plants reaching or surpassing their retirement age to new capacity sources. And the rise in
 6 demand only accelerates that need for additional generation.

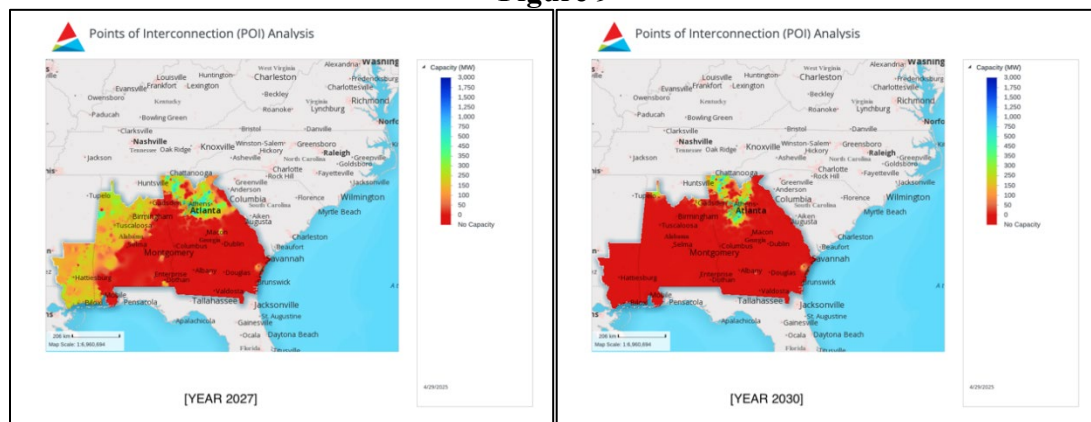
7 The graph also shows that, with the exception of the Vogtle nuclear units, the vast majority
 8 of generation development since 1990 has been in natural gas plants. Although Georgia
 9 Power’s current generation portfolio includes a mix of resources, the trend toward
 10 homogeneity is concerning. Reliance on a less diverse generation mix places customers at
 11 risk of price spikes if fuel costs rise, as occurred in late 2022,⁵¹ and potential deliverability
 12 issues in extreme weather events when fuel is not available or the plants are not operational,
 13 as occurred during Winter Storm Elliott.

⁵¹ FERC-NERC Elliott Report at 54; *see also* Direct Testimony of Adams and Houston on behalf of Georgia Power Company, FCR-26, Docket No. 44902, at 6:1-7:6 (Feb. 28, 2023) (pointing to “geopolitical unrest, global supply chain constraints” as two of the reasons for “dramatic” fuel cost increases).

1 **Q. IS THERE SUFFICIENT CAPACITY ON THE EXISTING SYSTEM TO**
2 **INTERCONNECT NEW GENERATION?**

3 A. No. Southern's recently released [SIGHT](#) tool⁵² allows stakeholders and the public to
4 review available capacity at potential interconnection points within Southern's three-utility
5 footprint. Figure 9 provides two SIGHT tool snapshots from Years 2027 and 2030 which
6 show that there is extremely limited capacity for interconnection in the near term and even
7 less as time goes on.

8 **Figure 9**



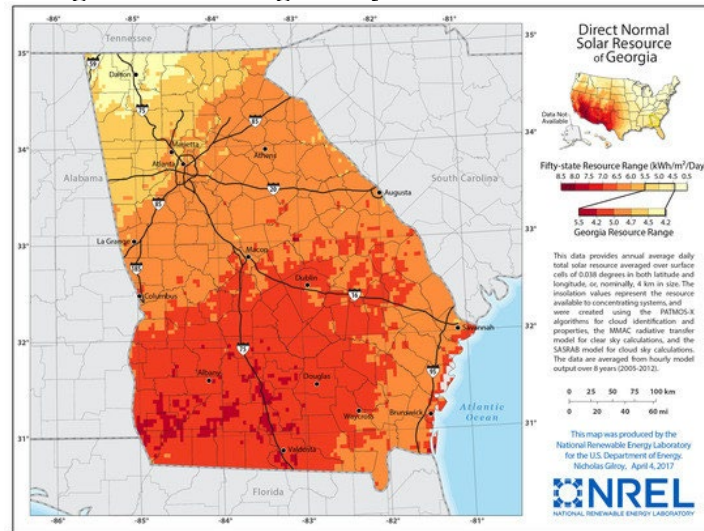
(Credit: Southern, *Points of Interconnection (POI)*, <https://sight.southernco.com/poi-analysis-map> (last visited May 1, 2025)).

9 Importantly, the most heavily constrained parts of the state also have the highest solar
10 potential, as shown in Figure 10.

⁵² Southern Company, Points of Interconnection Analysis, <https://sight.southernco.com/poi-analysis-map> (last visited Apr. 30, 2025).

1

Figure 10: Average Daily Total Solar Resource



(Credit: Nat'l Renewable Energy Lab'y, Solar Resource Maps and Data (2018),
<https://www2.nrel.gov/gis/solar-resource-maps>).

2

Taken together, these maps demonstrate the need for additional South to North transmission capacity, which would best enable Georgia Power to tap into additional low-cost generation resources in South Georgia.

3

4

Q. ARE THERE ANY REPORTS OR STUDIES THAT DESCRIBE HOW MUCH ADDITIONAL TRANSMISSION CAPACITY IS NEEDED TO SERVE GEORGIA POWER CUSTOMERS?

8

A. Yes. For example, the Department of Energy's Transmission Needs Study identifies expansion needs both within the Southeast region and to connect the Southeast to neighboring regions.⁵³ The Transmission Needs Study identifies a need to expand transmission within the region by 77% under a moderate load and high clean energy growth scenario and by 102% under a high load and high clean energy growth.⁵⁴ The Transmission Needs Study also identifies the need to exponentially increase the interregional transmission capacity between the Southeast and, respectively, the Mid-Atlantic, Midwest, Delta, and Florida regions.⁵⁵ (See Figure 11).

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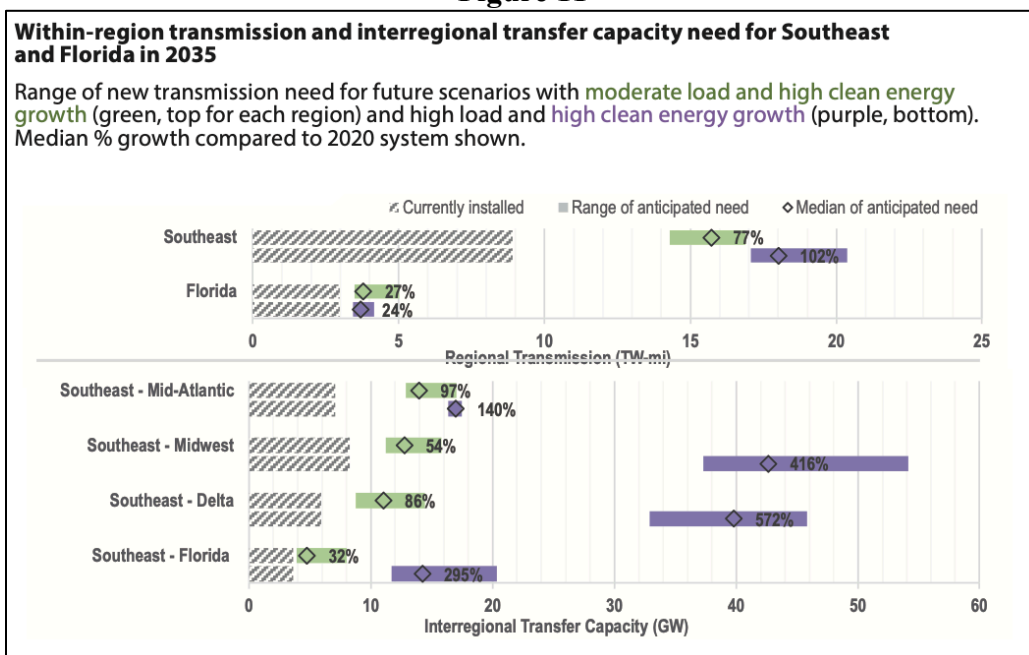
⁵³ See National Transmission Needs Study.

⁵⁴ *Id.* at vi-x.

⁵⁵ *Id.*

1

Figure 11



(Credit: U.S. Dep't of Energy, Fact Sheet: 2023 National Transmission Needs Study: Southeast and Florida 2, (Oct. 2023)).

2

V. COMMENTS ON GEORGIA POWER'S IRP FILING

3 **Q. PLEASE PROVIDE YOUR OVERALL ASSESSMENT OF GEORGIA POWER'S**
 4 **FILING.**

5 A. Compared to its earlier IRP filings, Georgia Power facially appears to have made a
 6 significant move in the right direction by proposing a broad Ten-Year Plan with a mix of
 7 projects, including several 500 kV “strategic transmission” projects that are aimed at
 8 augmenting south-north power flows and unlocking portions of the Southern footprint
 9 where there is potential to develop significant renewable energy resources.

10 However, I do not recommend that the Commission approve the transmission plan as filed
 11 without further investigation into the proposed projects and clear direction to evolve the
 12 planning process going forward. There are four reasons for this recommendation:

13 (1) Georgia Power is not following best transmission planning principles. It is important
 14 that the system be planned in a proactive and multi-value manner to avoid unnecessary,
 15 duplicative, and costly investments that customers will ultimately pay for.

1 (2) As a corollary to the failure to use best planning practices, the Ten-Year Plan was
2 developed in a vacuum with no meaningful stakeholder engagement. The lack of
3 transparency undermines the results.

4 (3) The plan does not demonstrate that Georgia Power seriously considered alternatives,
5 nor does it leverage widely available, state-of-the-art transmission technologies.

6 (4) The plan does not include any discussion of accompanying regional and interregional
7 solutions, which would provide some of the highest dollar value to customers, nor is there
8 evidence that such solutions are being considered in other venues.

9 **A. Incorporating proactive, multi-value transmission planning practices will benefit**
10 **customers.**

11 **Q. PLEASE DESCRIBE HOW GEORGIA POWER CURRENTLY CONDUCTS ITS**
12 **TRANSMISSION PLANNING PROCESS.**

13 A. Based on Georgia Power's IRP filing and testimony, it is my understanding that there are
14 theoretically at least three layers in Georgia Power's transmission planning process:

15 (1) internal planning, within Georgia Power covering its Georgia-based system, and more
16 broadly within its parent, Southern, covering Southern's entire three-state territory;⁵⁶

17 (2) a broader Georgia-state planning process through the ITS, which "consists of electric
18 transmission facilities (>40kV) that are individually owned and maintained by Georgia
19 Power Company ('GPC'), Georgia Transmission Corporation ('GTC'), MEAG Power
20 ('MEAG') and Dalton Utilities ('DU');"⁵⁷ and

21 (3) a regional planning initiative through the Southeastern Regional Transmission Planning
22 ("SERTP") process, which currently includes Southern, DU, GTC, MEAG, PowerSouth,

⁵⁶ 2025 Direct Hr'g Tr. 443:8-23; *see also* Georgia Power, 2025 Integrated Resource Plan, Tech. App'x 3 at 3 ("Transmission Planning-East (TP-E) of Southern Company Services (SCS) and Grid Transformation of GPC, are responsible for planning the transmission system for GPC. TP-E develops a planning model of the transmission system for the current year and for ten years into the future. This planning model is used to identify transmission problems and to evaluate alternative solutions to those problems.").

⁵⁷ Georgia Power, 2025 Integrated Resource Plan, Tech. App'x 3 at 1.

1 LG&E/KU, Associated Electric Cooperative Inc., TVA, and Duke Energy (DEC and Duke
2 Energy Progress), and will soon also include DESC and Santee Cooper.⁵⁸

3 Additionally, in direct testimony, Georgia Power explained that it sometimes also
4 “complet[es] transmission evaluations separate from and incremental to the standard ten-
5 year transmission planning processes. For example, Georgia Power’s transmission
6 planning process includes identification of strategic transmission projects that are included
7 in this filing.”⁵⁹

8 **Q. ARE THESE THREE PROCESSES ALIGNED?**

9 A. Not always. The internal Georgia Power and ITS processes seem to be more aligned as
10 they both address local planning needs—i.e., needs within the state of Georgia—and
11 Georgia Power “performs the responsibilities of Planning Coordinator” for two of the other
12 ITS members, MEAG and DU.⁶⁰

13 What is less clear is how Southern’s planning efforts across its three-utility system intersect
14 with the ITS process. For example, Georgia Power’s response to Data Request No. STF-
15 DEA-2-33 provides greater detail about the proposed project: GTC: LaGrange - North
16 Opelika 230kV (New Line), clarifying that

17 The Georgia Transmission Corporation (“GTC”): Lagrange-
18 North Opelika 230kV line provides an additional network
19 connection from Alabama Power Company (“APC”) into
20 Georgia and a high-capacity corridor to alleviate the West to
21 East flows. This new transmission line addresses thermal
22 constraints as defined in the Steady State Transmission Planning
23 Criteria of the NERC Reliability Standard (TPL-001-5) under
24 P1-Single Contingency event . . . North Opelika is owned by
25 APC; therefore, cost for these facilities will be incurred by GTC
26 and APC.

27 While this discovery response seems to indicate at least some level of coordination between
28 the Georgia ITS entities and Georgia Power’s affiliate Alabama Power Company, the IRP
29 documentation does not make clear whether the thermal constraints were based on

⁵⁸ Southeastern Regional Transmission Planning, *About Us*, <https://www.southeasternrtp.com/> (last accessed April 29, 2025).

⁵⁹ 2025 Direct Hr’g Tr. 147:22-148:2.

⁶⁰ Georgia Power, 2025 Integrated Resource Plan, Tech. App’x 3 at 34.

Georgia-specific models or if they resulted from a broader Southern analysis that also incorporated all the Georgia ITS participants.

Q. IS THE SERTP PROCESS ALIGNED WITH THE LOCAL PLANNING PROCESSES?

A. No. The SERTP process, which is the region’s designated FERC Order No. 1000 regional planning process, seems to be less well aligned with either Georgia Power’s or the ITS local planning processes. It is my understanding that the base plan considered in the SERTP process is not an independent region-wide modeling/cost-benefit analysis, but rather an aggregation of each of the sponsoring entities’ local transmission plans. However, there appear to be discrepancies between the information presented in local planning processes versus the SERTP process. For example, a recent report from the Brattle Group found that “SERTP studies include just 12% of the 80 GW of new generation identified as needed by the most recent IRP studies.” (See Figure 12).⁶¹

This is particularly concerning for Georgia Power as it is projecting the highest levels of load growth compared to other SERTP sponsors and, thus, could benefit most from the access to new generation that regional transmission facilities enable. (See Figure 13).

Figure 12

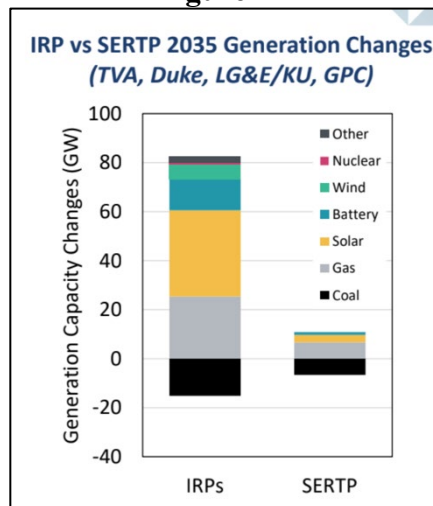
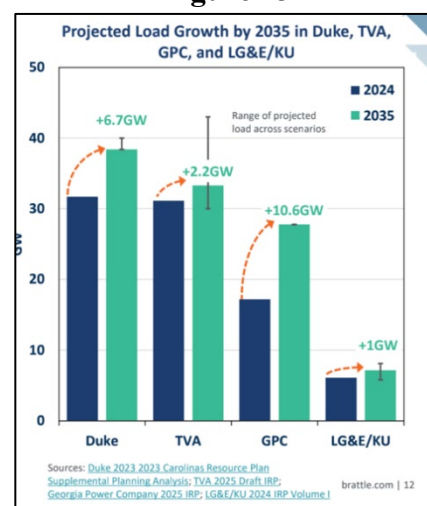


Figure 13



(Credit: Brattle Report at 4, 12).

⁶¹ Michael J. Hagerty, et al., Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy 4 (Apr. 2, 2025), https://carolinasceba.com/wp-content/uploads/2025/04/SERTP-Report-Summary_FINAL.pdf (“Brattle Report”).

1 In other words, SERTP is not planning with a full deck of information; while ostensibly
2 planning for the entire Southeast region, it is not using the full generation or demand
3 assumptions included in its members' IRPs, including Georgia Power's.

4 **Q. IS THE MISALIGNMENT PROBLEMATIC?**

5 A. Yes. The grid is integrated, and if planners are using different assumptions and information
6 to determine the need for transmission, the solutions that come out of these processes will
7 be suboptimal. Moreover, this issue calls into question the SERTP utilities' annual
8 determination that they have not identified any regional transmission solutions that are
9 more efficient or cost effective than the locally identified solutions.

10 **Q. YOU STATED THAT GEORGIA POWER IS NOT USING BEST PLANNING**
11 **PRACTICES, COULD YOU PLEASE EXPLAIN FURTHER?**

12 A. Yes. Compared to its last IRP, Georgia Power seems to have made some positive
13 movement towards better planning by incorporating multiple load sensitivities into its
14 resource planning analysis,⁶² but it did not include these load scenarios in its transmission
15 analysis.⁶³ And as addressed in Section V.B, the lack of stakeholder engagement in
16 developing these scenarios and load growth assumptions raises questions about the
17 reasonableness of the information.

18 Other areas where Georgia Power's process does not align with best planning processes
19 include:

- 20 • Georgia Power plans its generation resources on a twenty-year basis, but it plans
21 transmission on a ten-year forward basis and generally only scopes, estimates, and
22 budgets projects for the first five years of the planning horizon.⁶⁴
- 23 • The Ten-Year Plan continues to be a reactive and short-term examination rather
24 than a forward-looking identification of the transmission projects that can best help

⁶² See, e.g., Response to Data Request No. STF-JKA-1-1 Attach. b (providing various sensitivities).

⁶³ See, e.g., Response to Data Request No. STG-GS-2-6 (noting that "for consideration of the base ten-year plan, the Company takes into consideration firm and future firm generation and load"); see also 2025 Direct Hr'g Tr. 732:10-13 (noting that only the MG0 scenario was used to develop the transmission plan).

⁶⁴ Georgia Power, 2025 Integrated Resource Plan, Tech. App'x 3 Sec. 6a.

1 build capacity, reliability, and resiliency.⁶⁵ In particular, Georgia Power examines
2 transmission needs to ensure that there are no current or expected reliability
3 violations and to connect generation choices, rather than maximizing the
4 capabilities of the system. Even the strategic projects, which Georgia Power states
5 are designed to solve multiple constraints, including some of the projected load
6 growth,⁶⁶ are reactive to reliability issues, specifically thermal and voltage
7 problems.⁶⁷

- 8 • In selecting projects, Georgia Power considers only a limited set of benefits,
9 undervaluing the need for the transmission projects and the benefits that these
10 projects could bring to customers.

11 **Q. WHY ARE THE TEN-YEAR TRANSMISSION PLANNING AND FIVE-YEAR**
12 **PROJECT LOADING HORIZONS PROBLEMATIC?**

13 A. The ten-year planning and five-year loading horizons are problematic for three reasons: (1)
14 transmission lines are long-lived assets and longer planning horizons better value the
15 lifespan and network role of the infrastructure, (2) it can take multiple years to fully develop
16 and energize a transmission project and planning projects for only the next five years means
17 Georgia Power may prolong the construction timelines, and (3) because transmission is a
18 supply-side resource, it should be considered on a comparable basis as other supply-side
19 inputs in Georgia Power's IRP.

20 **Q. DOES GEORGIA POWER AGREE THAT TRANSMISSION PLANNING**
21 **HORIZONS SHOULD BE ELONGATED?**

22 A. Yes. Georgia Power has recognized that industry standards are moving toward longer-term
23 planning horizons in regional planning processes, stating that "strategic planning beyond
24 ten years will be an important part of Georgia Power's planning process going forward."⁶⁸
25 Georgia Power further stated in the Main Document of its 2025 IRP that:

⁶⁵ *Id.* Sec. II.A (noting that the planning conducted by Southern Company Services – Transmission is concerned with "maintaining system models" and includes steady state, stability, and short circuit studies).

⁶⁶ Response to Data Request No. STF-GS-2-6(a).

⁶⁷ Response to Data Request No. STF-DEA-4-69.

⁶⁸ Georgia Power, 2025 Integrated Resource Plan at 114.

1 The Company's longer-term planning horizon will ensure
2 projects are identified with sufficient lead time to provide timely
3 construction and optionality while balancing the appropriate
4 local customer value with regional considerations. System needs
5 and growth continue to move at an extraordinary pace, and it is
6 prudent to strategically plan and expand transmission capacity
7 with local future siting considerations that accommodate a range
8 of generation options and load growth needs and keep Georgia
9 Power customer needs at the forefront. Demonstrating a robust,
10 locally developed plan to meet these longer-term needs will also
11 feed into future regional planning processes, focusing on
12 projects that provide value and benefit customers.⁶⁹

13 During the hearing on Georgia Power's direct testimony, Georgia Power witness Robinson
14 testified that Georgia Power had been developing these changes even before FERC issued
15 Order No. 1920 on regional transmission planning, which requires at least a 20-year
16 planning horizon in regional planning processes like SERTP.⁷⁰

17 **Q. HAS GEORGIA POWER SHARED THE PROCESS IT PLANS TO USE TO**
18 **EXTEND THE PLANNING PROCESS TO 20 YEARS?**

19 A. No. While these planned changes are a positive sign that Georgia Power understands
20 why—given the major changes coming to the energy system from load growth, extreme
21 weather, and changing resource mix, among others—it is important to look out beyond 10
22 years and prepare for a variety of circumstances, Georgia Power has provided scant detail
23 about how the new planning horizon will be implemented.

24 Specifically, during the hearing on Georgia Power's direct testimony, Georgia Power
25 witness Robinson testified that the 20-year planning process was “still under
26 development.”⁷¹ He followed this statement with a broad explanation that:

27 [T]he 20-year plan process that we're working on looks at
28 informing our transmission plan and our resource plan on
29 assumptions across the system, looking at scenarios of different
30 load penetrations, looking at access to different sources of
31 generation, particularly looking at where you've got maybe
32 cheaper gas or access to carbon capture, where you've got
33 renewables, where you've got potential site development for

⁶⁹ *Id.*

⁷⁰ 2025 Direct Hr'g Tr. 734:11-15.

⁷¹ *Id.* at 734:20-735:6.

1 potential further nuclear. And then all of that is put forward in
2 this integrated system planning process and develop a plan that
3 is beyond the 10-year plan looking at the 11 through the 20th
4 year.⁷²

5 **Q. PLEASE EXPLAIN HOW GEORGIA POWER CAN ENGAGE IN PROACTIVE,**
6 **MULTI-VALUE PLANNING RATHER THAN REACTIVE, RELIABILITY-**
7 **ONLY FOCUSED PLANNING.**

8 A. In a proactive planning process, the utility conducts a forward-looking analysis that:
9 (1) identifies whether new transmission solutions can help prepare the system for potential
10 known and unknown network changes and (2) addresses multiple need drivers in addition
11 to reliability. In an ideal proactive plan, Georgia Power would run a multi-value scenario
12 analysis that considers not only reliability issues, but also at a minimum, examines:
13 expected projected load growth under both status quo and high-growth load scenarios,
14 impacts of generator retirements, whether new transmission would increase import or
15 export capability, whether transmission upgrades could result in increased system
16 efficiency and reduced line losses, and whether new or upgraded transmission would
17 increase economic efficiency.

18 Georgia Power's transmission plan examines only one generation scenario, and it does not
19 appear to have incorporated any of the other planning elements in either its base case or
20 strategic plan. Rather, Georgia Power has confirmed that it limited its transmission
21 expansion plan to meeting basic reliability needs only.⁷³

⁷² *Id.*

⁷³ For example, Data Request No. STF-DEA-4-6(b) sought information on how the identified project will "contribute to reducing grid congestion and ensuring grid resilience during peak load conditions." Georgia Power's response was limited to thermal and voltage—i.e. reliability considerations—and makes no mention of the economic impacts. Similarly, in its Response to Data Request No. STF-DEA-4-6(b) at 2, the Company states that:

[t]he transmission projects address multiple thermal overloads identified as part of the Georgia Integrated Transmission System ("ITS") transmission planning processes in compliance with NERC TPL-001-5. . . . Results of the transmission planning processes are noted in the thermal and voltage problem reports provided in Sections H1A and H1B of Technical Appendix, Volume 3.).

1 **Q. YOU ALSO MENTIONED THAT GEORGIA POWER DOES NOT CONSIDER**
2 **THE FULL BENEFITS OF TRANSMISSION. CAN YOU EXPLAIN FURTHER?**

3 A. Yes. Transmission provides extensive network benefits to customers, and if it is
4 undervalued, then a utility may not be building sufficient transmission resources to support
5 affordable and reliable service. In Response to Data Request No. STF-GS-1-2, Georgia
6 Power makes clear that it does not model certain benefits at all, noting that “[p]roduction
7 cost savings or generator capacity costs savings are not assessed during the [transmission]
8 project assessment process.”

9 To the extent Georgia Power models benefits, it does so in a qualitative rather than a
10 quantitative matter. For example, in the IRP Technical Appendix Volume Three,
11 Section 6d, Georgia Power explains that its:

12 evaluation process is a cost/benefit analysis. Costs can be
13 measured with a fair degree of accuracy. Benefits are measured,
14 if they can be measured at all, in other terms. Thus, in comparing
15 alternative projects, the cost/benefit ratio cannot be stated in
16 absolute terms.

17 Similarly, in response to Data Request No. STF-GS-2-8 (emphasis added), Georgia Power
18 states that:

19 The benefit-to-cost analysis performed by the Company is an
20 iterative and *qualitative analysis* comparing the preferred and
21 alternative solutions for each project listed in the ten-year plans
22 detailed in Sections H1a and H1b. Considerations in this
23 qualitative analysis between greenfield and brownfield projects
24 include, but are not limited to, estimated project costs, ability to
25 take outages on the system to facilitate the solution (particularly
26 important when weighing a solution that involves multiple line
27 rebuilds in an area), transmission capacity added to the system,
28 and power flow trends in an area.

29 **Q. WHAT BENEFITS SHOULD GEORGIA POWER BE CONSIDERING?**

30 A. At minimum, Georgia Power should be considering the following benefits, all of which are
31 standard energy system benefits:⁷⁴

⁷⁴ Additional information on transmission benefit accounting can be found in Brattle Report at 37 and Johannes Pfeifenberger, et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and*

- the full suite of production cost savings (including, reduced congestion and energy losses, reduced production costs during extreme events and system contingencies, and impact of generation outages);
- reliability and resource adequacy benefits;
- generation capacity cost savings;
- fuel diversity and system flexibility; and
- reduced cost of future transmission needs.

Q. ARE THERE ANY EXAMPLES IN THE COMPANY’S TEN-YEAR PLAN THAT DEMONSTRATE THAT PROACTIVE, MULTI-VALUE PLANNING WOULD HAVE BEEN BENEFICIAL?

A. Yes. In the response to Data Request No. STF-DEA-2-23, the Commerce – East Maysville Area Study, Georgia Power provided an attachment explaining its plan to build and upgrade transmission lines to serve a data center customer, stating that:

The recommended plan of constructing the Midway – Pond Fork 115 kV line alleviates the thermal loading limitations caused by the identified contingencies and does not necessitate brute force rebuilds of existing 115kV lines in the area recently rebuilt with 100C 1351 ACSR conductor.

In short, due to increased demand from this data center customer, Georgia Power decided it must build a brand new 115 kV after having just recently rebuilt nearby lines.

While there is no guarantee that a multi-value analysis would have presented a solution that would have resolved both the rebuild and the additional load growth needs, a proactive analysis could have determined a better, higher capacity solution at the outset instead of subjecting customers to the cost of two low-voltage projects in the same vicinity. Moreover, a comprehensive benefit analysis would be helpful in determining if a project is needed even if projected load growth does not materialize.

Reduce Costs (Oct. 2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf.

1 **Q. DO YOU HAVE ANY OTHER COMMENTS YOU WOULD LIKE TO MAKE**
2 **ABOUT PLANNING BEST PRACTICES?**

3 A. Yes. Best planning principles also call for iterative generation and transmission modeling
4 to identify the highest benefit-to-cost ratio and the lowest overall system cost that will
5 provide needed reliability. As I noted in my testimony in the updated IRP proceeding last
6 year, Georgia Power examines transmission needs only to the extent they may be needed
7 to serve their proposed generation solutions.⁷⁵ Georgia Power provides no analysis of the
8 flip side to that equation—whether integrating transmission solutions with generation
9 solutions will result in a more cost-effective and reliable network. Indeed, Georgia Power
10 witnesses have made clear that transmission is not included in the Commission’s
11 generation expansion models.⁷⁶

12 Moreover, as Georgia Power’s benefit analysis is qualitative, versus quantitative, it is
13 difficult for customers to understand the overall value of the proposed projects.

14 **B. Meaningful stakeholder engagement would improve the credibility of Georgia**
15 **Power’s planning results.**

16 **Q. HOW DOES STAKEHOLDER INPUT PLAY A ROLE IN BEST**
17 **TRANSMISSION PLANNING PRACTICES?**

18 A. As I discussed in the introduction, utility planning was historically conducted in a black
19 box. In contrast, modern best planning practices are employing more open and transparent
20 processes that allow all stakeholders—not just other utilities and transmission providers—
21 to vet and inform the planning scenarios and assumptions to ensure they match probable
22 network changes.

⁷⁵ See Response to Data Request No. STF-JKA 1-5 (listing the inputs to the supply side models but excluding transmission).

⁷⁶ 2025 Direct Hr’g Tr. 503:16-18 (Company Witness Grubb explaining that “[s]o the expansion plan serves several roles. One, is to give you an indication of what those technologies are. It does not factor in transmission. We do that in the RFPs.”).

1 **Q. PLEASE DESCRIBE OPPORTUNITIES FOR STAKEHOLDER ENGAGEMENT**
2 **WITHIN THE SOUTHERN/GEORGIA POWER INTERNAL PLANNING**
3 **PROCESS AND THE GEORGIA ITS PLANNING PROCESS.**

4 A. There are no opportunities for stakeholder engagement in these processes. Both the internal
5 Southern/Georgia Power and ITS planning processes are closed to outside input,⁷⁷ with the
6 study assumptions chosen and models run internally before customers or the broader public
7 get a chance to weigh in. The opportunity to weigh in occurs only after the results are filed
8 in the IRP docket every three years.

9 At hearing, Georgia Power Witness Robinson alleged that: “the ITS has functioned very
10 well for 50 years, taking into consideration input from Georgia Power, from the EMCs,
11 from the municipalities, and their resource providers to ensure that we are planning and
12 building the system appropriately.”⁷⁸ But what has worked for the past 50 years will not
13 work for the next 50. Transparency can make Georgia Power’s process run smoother and
14 deliver better outcomes for customers.

15 **Q. IN YOUR OPINION, IS THE IRP PROCESS ITSELF A SUFFICIENT**
16 **OPPORTUNITY FOR STAKEHOLDER ENGAGEMENT?**

17 A. No. During the IRP process, stakeholders can offer *reactive* feedback on a limited snapshot
18 of Georgia Power’s transmission plan. Of course, Georgia Power’s transmission plan is
19 constantly evolving, and we hope Georgia Power staff will integrate feedback received
20 during the IRP. But there are no formal opportunities for stakeholders to share their
21 *proactive* input while the transmission plan is under development.

22 **Q. PLEASE DESCRIBE THE STAKEHOLDER OPPORTUNITIES THAT ARE**
23 **AVAILABLE IN THE SERTP PROCESS.**

24 A. SERTP—the regional planning process for the Southeast—invites stakeholders to
25 participate in quarterly meetings and to offer input on regional transmission plans at a
26 single point in time: during the Second Quarter meeting each June after the preliminary
27 expansion plan is unveiled. At this time, stakeholders can also bring their own suggestions

⁷⁷ *Id.* at 537:4-14.

⁷⁸ *Id.* at 539:2-9.

1 of projects for SERTP to include in its plans. SERTP presents the final expansion plan
2 during the Fourth Quarter meeting each December.

3 **Q. IN YOUR OPINION, IS THIS A SUFFICIENT OPPORTUNITY FOR**
4 **STAKEHOLDER ENGAGEMENT IN GEORGIA?**

5 A. No. Georgia Power voluntarily decides which projects in its Ten-Year Plan are fed into the
6 SERTP process, meaning they may not all be included. Moreover, the SERTP proceedings
7 use very limited criteria to determine if any regional transmission projects could displace
8 the need for local projects within individual utilities' expansion plans. By that point, it is
9 too late for stakeholders to help shape the foundational assumptions and project proposals.
10 If outside parties cannot share their input on the local plan before it gets baked into SERTP,
11 then it's not sufficient stakeholder engagement.

12 **Q. DO YOU HAVE OTHER CONCERNS ABOUT THE LACK OF**
13 **TRANSPARENCY AT SERTP?**

14 A. Yes. The quarterly cadence of the SERTP meetings, and effective restriction of stakeholder
15 input to the period immediate following the Second Quarter meeting, can impede the
16 already limited ability of stakeholders to comment on proposals. For example, one of
17 Georgia Power's "strategic" transmission lines—the Ashley Park – Wansley line—has a
18 listed "start date" of December 1, 2024, but it was only shared with SERTP for the first
19 time on December 10, 2024, a week and a half later. During the Second Quarter meeting
20 in June 2024, when the preliminary expansion plan was presented, there was no mention
21 of this project. The "start date" indicates when Georgia Power "would originate that
22 project, starting activities associated with that project. That would be preliminary siting of
23 that line, as well as beginning engineering, working towards [the] in-service date."⁷⁹

24 **Q. HAS GEORGIA POWER EXPLAINED WHY THAT PROJECT WAS NOT**
25 **SHARED WITH SERTP ANY EARLIER?**

26 A. At the hearing, Georgia Power witness Robinson explained that the project was not
27 identified by June. But during the summer, "a lot of assumptions were updated, particularly

⁷⁹ *Id.* at 541:9-13.

1 coming out of the updated IRP from last year.”⁸⁰ Mr. Robinson further stated that, as a
2 result, Georgia Power had to “recreate the entire ten-year plan process,” and the Ashley
3 Park – Wansley line was “identified later in the year, closer to quarter four.”⁸¹

4 **Q. WHY IS THIS INCIDENT CONCERNING?**

5 A. Again, by the time Georgia Power shared this project with SERTP, it was too late for
6 stakeholders to do anything about it. SERTP often feels like an afterthought, but, currently,
7 it is the only venue for stakeholders to have any say on transmission planning in Georgia.

8 Moreover, the Ashley Park – Wansley line is just one of many ITS projects that were first
9 introduced at the December 10th SERTP meeting that had start dates of December 1, 2024,
10 or earlier in 2024. While Georgia Power has designated the costs of all projects, including
11 these late-introduced projects, as trade secret, the total impact on customers is significant.
12 The prevalence of multiple Fourth Quarter updates diminishes the value of the lone existing
13 opportunity to provide input during the previously held Second Quarter meeting.

14 **Q. WHY SHOULD GEORGIA POWER PROVIDE MORE OPPORTUNITIES FOR**
15 **STAKEHOLDER ENGAGEMENT?**

16 A. At the end of the day, Georgia customers are responsible for the cost of developing,
17 maintaining, and operating the transmission system, and parties representing their interests
18 should have a seat at the table.

19 Stakeholder engagement will also benefit Georgia Power. For example, getting outside
20 input as early as possible can improve the accuracy of planning inputs and prevent
21 opposition during the IRP process. Certain stakeholders, such as large energy consumers,
22 can provide unique insight into their energy needs with a fuller picture, which will impact
23 transmission planning.

24 For example, after Georgia Power filed its 2023 Updated IRP, Microsoft filed comments
25 which noted that Georgia Power “potentially over-estimates new load that will select GPC
26 as a provider.”⁸² Microsoft recommended that Georgia Power determine a data center’s

⁸⁰ *Id.* at 540:21-25.

⁸¹ *Id.* at 541:1-5.

⁸² Microsoft Comments on Georgia Power’s 2023 Integrated Resource Plan Update, Docket No. 55378 (Ap. 1, 2024).

1 level of “commitment” to seek power in Georgia and to “provide greater transparency to
2 stakeholders regarding its large load forecasting methodology and the underlying data used
3 to support it.”⁸³

4 Of course, any energy forecast is inherently imprecise because you cannot predict the
5 future, but informed planning with stakeholder engagement ensures the forecasts are as
6 reasonable as possible. And any company with plans to expand its data center footprint
7 should want to be at the table with Georgia Power as it will be responsible for a substantial
8 portion of the costs associated with connecting and serving that load.

9 **Q. GEORGIA IS A VERTICALLY INTEGRATED STATE. IS STAKEHOLDER**
10 **ENGAGEMENT LIMITED TO REGIONAL TRANSMISSION**
11 **ORGANIZATIONS (“RTO”) WHERE THE REGIONAL OPERATOR PLANS**
12 **THE GRID FOR MULTIPLE UTILITIES?**

13 A. No, stakeholder outreach should not be, and is not, limited to RTO regions. For example,
14 Duke Energy recently revamped the local transmission planning process it runs through
15 the Carolinas Transmission Planning Collaborative (“CTPC”) to adopt many of the
16 proactive, multi-value planning methodologies described above.

17 As part of its process, the CTPC convenes a Transmission Advisory Group (“TAG”) where
18 interested parties can share input on the development of Duke Energy’s annual local
19 transmission plan.⁸⁴ TAG participants provide input on topics such as study criteria,
20 assumptions, and methodology (such as planning horizons) and the development of local
21 solutions. TAG members can also request to review base case models and give input on
22 whether the models in fact represent study assumptions the CTPC approved.⁸⁵ Multiple
23 stakeholder groups have expressed their support for the new CTPC process.⁸⁶

⁸³ *Id.*

⁸⁴ *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Re-Filing of Proposed Revisions to Local Transmission Planning Process in Attachment N-1 of Joint OATT, FERC Docket No. ER24-874 (filed Jan. 12, 2024).

⁸⁵ *Id.*

⁸⁶ Ethan Howland, Clean Energy Groups Back Duke Energy Multi-Value Local Transmission Planning Proposal, Utility Dive (Feb. 5, 2024), <https://www.utilitydive.com/news/duke-energy-carolinas-progress-multi-value-local-transmission-planning-collaborative-ferc/706519/>.

Q. IS THERE ANOTHER EXAMPLE OF A VERTICALLY INTEGRATED UTILITY THAT OFFERS OPPORTUNITIES FOR STAKEHOLDER ENGAGEMENT IN UTILITY TRANSMISSION PLANNING PROCESSES?

A. Yes. Idaho Power seeks customer input during the development of its IRP every two years. The company's Integrated Resource Plan Advisory Council includes large industrial customers, environmental groups, irrigation representatives, state and local elected officials, utility commission representatives, and others.⁸⁷ In a series of public meetings—held in the months before Idaho Power files its IRP—Idaho Power presents, and seeks feedback, on various IRP-related topics including:

- Reserve Requirements Methodology
- Future Supply-side Resources
- Carbon Outlook and Modeling Scenarios
- Forecasts for Natural Gas, Energy and Demand, and Energy Efficiency and Demand Response
- Reliability and Capacity
- Natural Gas Conversion
- Load Forecast
- Transmission
- Modeling Update, Preliminary Results; and
- Preferred Portfolio

Q. DOES GEORGIA POWER RUN ANY STAKEHOLDER WORKING GROUPS?

A. Yes. For example, Georgia Power has a working group focused on its Demand Side Management (“DSM”) portfolio. Georgia Power’s “DSM Program Planning Approach,” is a Commission-approved, nine-step process that is intended to include collaboration with stakeholders.

Q. CAN YOU DESCRIBE THE STAKEHOLDER ENGAGEMENT?

A. Yes. In direct testimony, Georgia Power witnesses explained that as part of the 2025 IRP process, Georgia Power met with its DSM Working Group (“DSMWG”) to “develop, discuss, and refine DSM concepts.”⁸⁸ The witnesses further stated that Georgia Power has engaged with its DSMWG eight times since 2022 to “discuss proposed program

⁸⁷ Idaho Power, *Our 20-Year Plan*, <https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/our-twenty-year-plan/> (last accessed Apr. 29, 2025).

⁸⁸ 2025 Direct Hr’g Tr. 768:16-17.

1 modifications and new initiatives,” and engaged separately with a subset of the DSMWG
2 to “specifically work through program ideation.” They further noted: “This process ensured
3 broad stakeholder input in the DSM program development process.”⁸⁹ Getting stakeholder
4 buy-in for demand side program is, of course, critical to ensuring the programs are well-
5 utilized. But stakeholder engagement on transmission is even more valuable, since energy
6 customers in Georgia *do* rely on the transmission system and *will* pay for it through their
7 energy bills.

8 **Q. YOU HAVE EXPLAINED WHY STAKEHOLDER INPUT IS SO IMPORTANT.**
9 **SHOULD UTILITIES FULLY RELY ON OUTSIDE INPUT TO DEVELOP**
10 **THEIR TRANSMISSION PLANS?**

11 A. No. Utilities are still the transmission planning experts and have legal obligations to plan
12 their systems in accordance with established reliability standards. But that doesn’t mean
13 planning should be done in a black box.

14 **Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT TRANSPARENCY?**

15 A. Yes. It is concerning that Georgia Power does not share publicly its estimated cost
16 information for its proposed transmission projects.

17 **Q. WHY IS THIS CONCERNING?**

18 A. First and foremost, the sole reason the Georgia Power electric network exists is to serve
19 customers, and it is those customers who are also responsible for paying for the system.
20 Customers should have an opportunity to understand the potential costs of proposed
21 projects so they can understand what makes up their utility rates. Because Georgia Power
22 treats all estimated transmission cost information as trade secret, it cannot be discussed
23 openly at hearings where the public and customers participate. The Ten-Year Plan includes
24 208 projects,⁹⁰ the costs impacts of which are sizeable but hidden from customers. And if
25 projected load growth comes to fruition, those potential costs may rise.

26 Second, although certain stakeholders may sign a non-disclosure agreement to access the
27 cost information, that access to trade secret material is limited to the sole docket in which

⁸⁹ *Id.*

⁹⁰ Response to Data Request No. STF-DEA-6-1.

1 it is offered. Transmission has long lead times, which means the same proposed lines may
2 be considered in multiple Commission proceedings. But even those stakeholders with
3 access to “trade secret” cost information in this proceeding are not permitted to raise
4 information in a later proceeding. Similarly, some of the projects presented—in particular,
5 the strategic projects—are also addressed in other transmission planning processes, such
6 as SERTP meetings. Although Georgia Power claims that the SERTP process is the right
7 space for stakeholders to engage on transmission issues, its choice to label the Ten-Year
8 Plan’s cost and need information as trade secret means that stakeholders are prohibited
9 from raising questions around costs or areas of potential alignment or misalignment in
10 SERTP proceedings if such questions arise from information filed here.

11 **Q. GEORGIA POWER SUBMITTED AN AFFIDAVIT PROVIDING THE BASIS**
12 **FOR PROTECTING COST INFORMATION AS TRADE SECRET. DO YOU**
13 **AGREE WITH ITS ASSERTION?**

14 **A.** No. Georgia Power’s assertion is not valid. In short, Georgia Power claims that making the
15 cost information public would provide an undue advantage to its “competitors and
16 suppliers” including that it would “allow Georgia Power’s competitors and suppliers to
17 have access to the costs paid by the Company and insight into the Company’s transmission
18 planning process.”⁹¹ But as Georgia Power’s witness seemed to acknowledge at the
19 hearing, the Company does not have any competitors when it comes to building
20 transmission.⁹²

21 With respect to the concern about suppliers, the projects in the plan are simply proposals
22 and the budgets show only estimated costs of each of the overall projects.⁹³ Suppliers
23 provide costs for components of the projects. Sharing the overall budget does not provide
24 suppliers with a competitive advantage over pricing of components, especially as actual
25 supplier bids will depend on many factors, including final routing, final technology
26 choices, supply chain availability, etc. Moreover, the supplier role is to provide the

⁹¹ Georgia Power, 2025 Integrated Resource Plan, Tech. App’x 3 Trade Secret Assertion at 1.

⁹² 2025 Direct Hr’g Tr. 545:9-546:6.

⁹³ For example, in response to Data Request No. STF-GS-2-25, the Company explained that the costs for certain projects changed between the 2022 and 2025 IRPs because “[t]he cost for each project is revised through scoping, engineering, and design processes, which include but are not limited to the increase in material costs over the years.”

1 equipment and/or labor; Georgia Power has provided no explanation of how information
2 into Georgia Power's *planning process* would impact supplier bidding on final project
3 plans.

4 Additionally, if there was a real security or economic concern with sharing cost estimates,
5 then no utility would provide public cost estimates in their transmission plans, but that is
6 not the case.

7 **Q. CAN YOU PROVIDE EXAMPLES OF OTHER UTILITIES THAT PROVIDE**
8 **COST ESTIMATES IN THEIR PROPOSED TRANSMISSION PLANS?**

9 A. Yes. With respect to utilities in regional transmission organizations, estimated cost data is
10 provided, at minimum, through the regional transmission planning process.⁹⁴

11 **Q. IS ESTIMATED COST DATA FOR PROPOSED TRANSMISSION PROJECTS**
12 **PROVIDED BY ANY UTILITIES THAT ARE NOT LOCATED IN REGIONAL**
13 **TRANSMISSION ORGANIZATIONS?**

14 A. Yes. For example,

- 15 • Duke Energy provides estimated costs in its CTPC planning process (e.g., Carolinas
16 Transmission Planning Collaborative, Report on the CTPC 2024-2034 Collaborative
17 Transmission Plan 60-67 (Feb. 28, 2025),
18 https://carolinastpc.org/media/reference/2025/02/28/2024_CTPC_Collaborative_Transmission_Plan_FINAL_Report_02-28-2025.pdf);
- 20 • DESC provides project estimates through the South Carolina Regional Transmission
21 Planning Process (e.g., South Carolina Regional Transmission Planning, \$2M & Above
22 Project Descriptions, <https://www.scrtp.com/assets/pdfs/home/2024-2028-2million-and-above-project-descriptions.pdf> (last visited May 1, 2025));

⁹⁴ See, e.g., MISO Transmission Expansion Plan (last visited May 1, 2025), <https://www.misoenergy.org/planning/transmission-planning/mtep/#t=10&p=0&s=&sd=> (showing, for example, estimated costs of projects under evaluation); PJM Transmission Expansion Advisory Committee (last visited May 1, 2025), <https://www.pjm.com/committees-and-groups/committees/teac> (providing presentation slides with cost estimates for various proposed projects); SPP 2024 Integrated Transmission Planning Assessment Report (Jan. 24, 2025), <https://www.spp.org/media/2229/2024-itp-assessment-report-v10.pdf> (providing throughout the report cost estimates for proposed transmission projects).

- Black Hills Energy provides estimated project budgets as part of its annual transmission filing with the Colorado Public Utilities Commission (e.g., Black Hills Energy, *Transmission Projects*, <https://www.blackhillsenergy.com/transmission-rates-and-planning/transmission-projects> (last visited May 1, 2025));
- PacifiCorp provides estimated transmission cost information in its IRP workpapers (e.g., PacifiCorp, *IRP Support and Studies*, <https://www.pacifiCorp.com/energy/integrated-resource-plan/support.html> (last visited May 1, 2025)); and
- Idaho Power includes cost estimates for transmission projects in its IRP filing (e.g., Idaho Power, *Building Our Power: Integrated Resource Plan* (Sept. 2023), <https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/our-twenty-year-plan/>).

C. Additional information is needed about alternatives and the technologies Georgia Power has proposed to use in the Ten-Year Plan.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH GEORGIA POWER’S IRP?

A. Yes. Georgia Power does not appear to be following its own planning principles, which include the following:

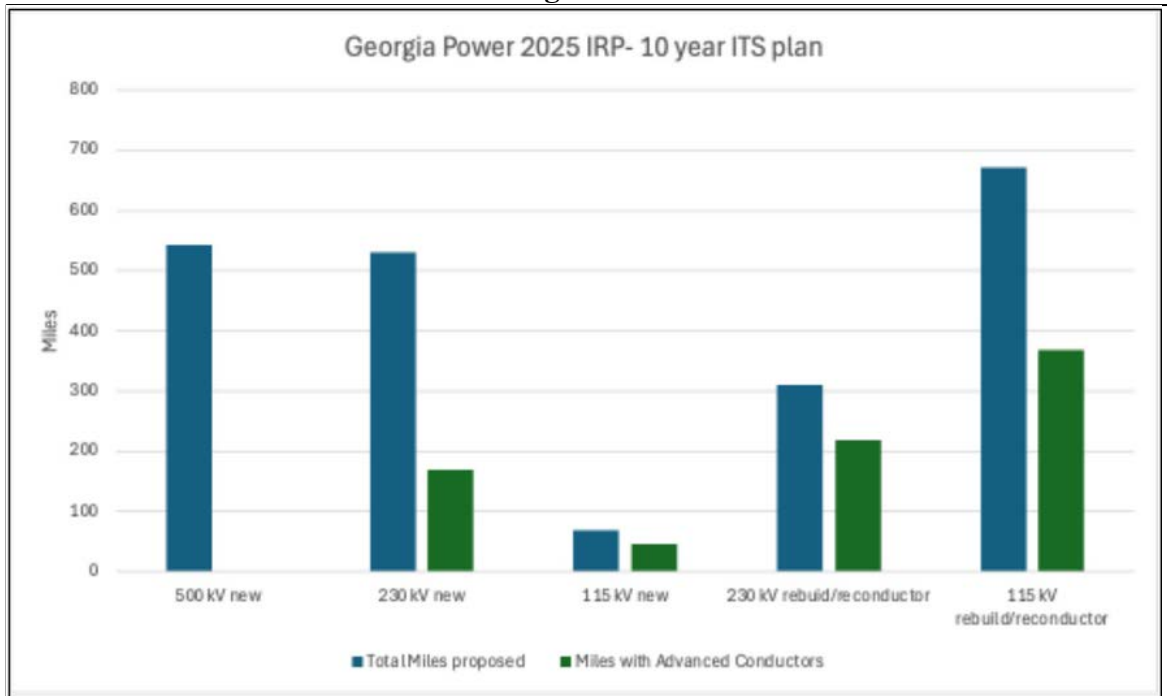
11. Minimize transmission losses when cost effective.
12. Minimize the loss of life to transmission equipment from forced operation at higher loading levels.⁹⁵

Two of the most cost-effective ways to address these principles are to build high-voltage lines and to integrate modern technologies, in particular, Advanced Conductors. First, the Ten-Year Plan is largely comprised of low-voltage (115-230 kV) lines, which as discussed above, provide minimal benefits and are typically less cost-effective when compared to high-voltage lines. Second, although Advanced Conductor technology can be used with both new and existing projects, Georgia Power is only considering Advanced Conductors for a limited set of its new projects and none of its proposed 500 kV projects.

⁹⁵ Georgia Power, 2025 Integrated Resource Plan, Tech. App’x at 3.

1 The chart below in Figure 14 provides a comparison of the total miles proposed in the Ten-
2 Year Plan by voltage and the number of miles of that proposal on which Georgia Power is
3 planning to use Advanced Conductors.

Figure 14



(Data Source: Responses to Data Requests No. STF-DEA-2-7 and STF-DEA-2-8).

4 **Q. WHY IS THIS A PROBLEM?**

5 A. As explained earlier, ACSR technology is over 100 years old. It has higher transmission
6 losses and offers less loading capability than ACCC and ACSS technologies. But rather
7 than building projects that are smart from the start, Georgia Power is proposing to use
8 ACSR technologies in all the 500kV projects and most of its 230kV projects.

9 **Q. HOW DOES GEORGIA POWER JUSTIFY THIS DECISION?**

10 A. Georgia Power claims that:

11 500kV New Transmission Lines will not be built using advanced
12 conductors, as it is more cost-effective to use standard
13 conductors for new structures and to gain more capacity from
14 the conductor. Advanced conductors are more applicable when
15 the Company is reconductoring an existing line to avoid the need
16 to replace structures or make extensive modifications to the
17 existing lines due to their lighter conductor weight and ability to
18 allow high current carrying capacity because they can operate at

1 higher temperatures than traditional conductors. However,
2 advanced conductors are not cost advantageous when building
3 new lines due to that higher cost.⁹⁶

4 **Q. WHAT ARE YOUR CONCERNS WITH GEORGIA POWER'S ANSWER?**

5 A. Georgia Power acknowledges the operational benefits of using more modern technologies
6 but summarily dismisses them as options with the claim that “advanced conductors are not
7 cost advantageous when building new lines due to that higher cost.” Georgia Power
8 provided no cost evaluations to back up this claim or allow the Commission or other parties
9 to verify its veracity.

10 Georgia Power's strategic projects will help unlock power in the southern portion of
11 Georgia and create opportunities for economic growth. However, customer dollars should
12 be used wisely and invested in projects that provide opportunity for the future rather than
13 those that may be capacity constrained from the start. And customers should not be required
14 to pay for older technology, only to have it replaced soon thereafter.

15 **Q. ARE YOU RECOMMENDING THAT ALL OF THE PROJECTS BE**
16 **CONVERTED TO ACCC OR ACSS TECHNOLOGIES?**

17 A. No. I am recommending that the Commission direct Georgia Power to provide quantitative
18 justification for choosing one technology over another so that the Commission can make
19 an informed decision as to whether Georgia Power's proposal is cost-effective for
20 customers. Simply declaring one more expensive than the other is not enough. The
21 Commission and stakeholders should be able to “trust but verify” Georgia Power's
22 proposal. Here there is neither reason to trust, nor the ability to verify.

23 Further, the quantitative cost calculations should not be based solely on the sticker price of
24 ACSR versus a more advanced technology. Rather, the calculations should account for the
25 full benefits of choosing these advanced technologies, including, but not limited to the
26 reductions in transmission losses, ability to operate at higher loading levels, resilience
27 benefits in the event of extreme weather, and the avoided cost of having to build additional
28 projects if ACSR is chosen over another conductor technology.

⁹⁶ Response to Data Request No. STF-DEA-2-7.

1 **D. The IRP should provide greater insight on Georgia Power's efforts to plan**
2 **regional and interregional transmission**

3 **Q. DO YOU HAVE ANY OTHER CONCERNS WITH GEORGIA POWER'S IRP?**

4 A. Yes. Georgia Power is part of an integrated network, but there is minimal information about
5 how Georgia Power's transmission plan fits within Southern's broader plan (discussed
6 above) or how it integrates into the larger regional/interregional network.

7 With respect to the latter, at the hearing Georgia Power witness Robinson discussed some
8 of the planning efforts that Georgia Power undertakes with neighboring utilities, including
9 with SERTP and Florida, but stated that he "[c]an't talk specifics today about that."⁹⁷ The
10 IRP filing similarly provides scant details on how Georgia Power plans to better integrate
11 with other regions.

12 **Q. AS DISCUSSED EARLIER, GEORGIA POWER CLAIMS THAT ITS SYSTEM**
13 **IS SUFFICIENTLY RELIABLE. IF THAT IS THE CASE, THEN WHY DOES**
14 **THE COMPANY NEED TO PROVIDE INFORMATION ABOUT BROADER**
15 **PLANS?**

16 A. The high price of imports and NERC ITCS Study belie the claim that the system is
17 sufficiently reliable. Moreover, planning within one utility footprint is the most expensive
18 way to provide customers with electric service.

19 For example, the Transmission Planning Study finds that:

20 When transmission regions coordinate to achieve resource
21 adequacy, system costs through 2050 are lowered by \$170–380
22 billion. In scenarios that allow coordination, transmission is used
23 bidirectionally across many regional interfaces to support
24 resource adequacy. Coordinated planning to enable external
25 resources to support local adequacy requirements increases the
26 motivation for interregional transmission expansion. When
27 resource adequacy requirements are met by in-region resources
28 only, 40%–60% less interregional transmission capacity is
29 added—resulting in the \$170–380 billion higher systemwide
30 costs.⁹⁸

⁹⁷ 2025 Direct Hr'g Tr. 444:4-12.

⁹⁸ Transmission Planning Study, Executive Summary at 15.

1 **Q. THE COMMISSION DOES NOT HAVE AUTHORITY OVER PLANNING IN**
2 **OTHER STATES, WHY SHOULD GEORGIA POWER PROVIDE**
3 **INFORMATION ABOUT THE BROADER SOUTHERN OR REGIONAL PLANS**
4 **HERE?**

5 A. The network is integrated, and it is important that the Commission and Georgia
6 stakeholders are provided information about how external connections can help support
7 reliable and affordable service. It is equally important for the Commission and stakeholders
8 to understand if increasing connections to neighbors could help lower costs and increase
9 affordability and how those connections would fit within the context of Georgia Power's
10 local transmission plan.

11 **E. Georgia Power customers would benefit from more proactive action by the**
12 **Commission.**

13 **Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING GEORGIA**
14 **POWER'S FILING OR STATUS QUO TRANSMISSION PLANNING IN**
15 **GEORGIA?**

16 A. Yes. I firmly believe that customers would benefit from more proactive action by the
17 Commission and Commission staff on this issue.

18 **Q. WHY ARE YOU RECOMMENDING THAT THE COMMISSIONERS AND**
19 **COMMISSION STAFF TAKE ON A MORE PROACTIVE ROLE WITH**
20 **RESPECT TO TRANSMISSION?**

21 A. Transmission touches on a number of core state concerns, including: maintaining
22 affordable rates, providing safe and reliable service, enabling economic opportunities, and
23 minimizing physical and siting impacts of infrastructure projects. Moreover, state
24 commissions are also on the frontlines of responding to customer concerns and complaints
25 regarding utility service and rates which, as discussed earlier, are impacted when the
26 transmission network is not appropriately robust. Given that additional transmission
27 capacity is needed to serve customers in the state, the Commission and Commission staff
28 have a unique opportunity to shape transmission planning processes and outcomes so that
29 they lead to more cost-effective decisions.

1 **Q. DOES THE COMMISSION’S STATUTORY AUTHORITY ALLOW IT TO**
2 **INFLUENCE THE PROCESSES AND OUTCOMES OF GEORGIA POWER’S**
3 **PROPOSED TRANSMISSION INVESTMENT DECISIONS?**

4 A. Yes. The Commission’s power stems from at least three sources.

- 5 • The Commission’s rate-setting authority over Georgia Power’s bundled rates;
- 6 • State law directing the Commission to make determinations as to the adequacy of
7 the IRP; and
- 8 • FERC orders outlining the role of states in regional transmission development.

9 **Q. PLEASE DESCRIBE THE COMMISSION’S RATE-SETTING AUTHORITY**
10 **WITH RESPECT TO TRANSMISSION.**

11 A. The Federal Power Act, 16 USC § 824, vests the federal government with jurisdiction over
12 “the transmission of electric energy in interstate commerce and the sale of such energy at
13 wholesale in interstate commerce” but limits the federal authority to regulate “only to those
14 matters which are not subject to regulation by the States.” Generally, this means that FERC
15 regulates the rates, terms, and conditions of service for transmission lines owned by FERC-
16 jurisdictional utilities such as Georgia Power. However, FERC has declined to assert its
17 jurisdiction over bundled retail rates—i.e., a single rate that reflects total generation,
18 transmission, and distribution charges in contrast to unbundled rates where generation,
19 transmission, and distribution charges are calculated separately.⁹⁹ In such cases, FERC
20 continues to maintain sole authority over Georgia Power’s wholesale transmission rates,¹⁰⁰
21 but the Commission has authority to review the transmission inputs into the retail rates.

22 Only 1.9% of Georgia Power’s revenues come from wholesale customers;¹⁰¹ consequently,
23 only a minimal portion of Georgia Power’s transmission charges are subject to FERC
24 oversight. The portion of Georgia Power’s system that is subject to the Commission’s
25 review, through Georgia Power’s rate case, comprises the vast majority of the revenue that

⁹⁹ See *New York v. FERC*, 535 U.S. 1, 25-26 (2002).

¹⁰⁰ See *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 953 (1986) (“FERC clearly has exclusive jurisdiction over the rates to be charged ... [to] interstate wholesale customers.”).

¹⁰¹ Georgia Power, *Facts & Figures*, <https://www.georgiapower.com/about/company/facts-and-figures.html> (last visited Apr. 23, 2025) (reporting information as of Dec. 31, 2023).

Georgia Power collects for its transmission facilities. In this role, the Commission is charged with reviewing the prudence of Georgia Power's transmission investment, including whether the investments are just and reasonable. It is in Georgia customers' best interests that the Commission take proactive action to promote prudent investment decisions prior to and during the IRP stage because once an investment is introduced in a rate case it is a sunk cost.

Q. PLEASE DESCRIBE HOW STATE LAW REQUIRING THE COMMISSION TO MAKE DETERMINATIONS AS TO THE ADEQUACY OF THE IRP INTERSECTS WITH TRANSMISSION PLANNING AND DEVELOPMENT.

A. Under O.C.G.A. § 46-3A-2, every Georgia regulated utility must file an IRP with the Commission every three years, and the Commission must make a determination as to the adequacy of the filing. Commission Rule 515-3-4-.01(2) establishes that such a decision will be based on the Commission's determination that the plan is in the public interest.

The linkage between the IRP and transmission arises out of how the Commission defines the IRP and supply-side resources. Commission Rule 515-3-4-.02(25) defines the IRP planning process as:

A utility resource planning process in which an integrated combination of demand-side and supply-side resources is selected to satisfy future energy service demands in the most economic and reliable manner while balancing the interests of utility customers, utility shareholders and society-at large. In IRP, all resources reasonably available to reliably meet future energy service demands are considered by the utility on a fair and consistent basis.¹⁰²

Transmission expansion and modernization fall under the ambit of supply side resources. In particular, the Commission defines "supply-side resource" as a:

A resource which can provide for a supply of electrical energy and/or capacity to the utility. Supply-side resources include supply-side capacity options, supplies from other utilities, cogenerators, renewable resource technologies, or independent third parties via existing or new transmission facilities; and **the life extension, upgrading, plant refurbishment, efficiency**

¹⁰² Ga. Comp R & Regs. 515-3-4-.02(25).

1 **improvement, or capital additions of** existing generation,
2 **transmission** or distribution facilities of the utility.¹⁰³

3 **Q. DO YOU AGREE THAT TRANSMISSION SHOULD BE TREATED AS A**
4 **SUPPLY-SIDE RESOURCE?**

5 A. Yes. Although transmission does not generate actual electrons, transmission provides
6 multiple supply-side functions including:

- 7 • providing access to power generation from diversified locations, including
8 generation resources within the utility footprint and resources located in
9 neighboring utility footprints;
- 10 • reducing the need to procure peaking resources by improving capacity access from
11 existing generation and providing access to energy from wider geographic areas,
12 some of which may may have different peak demand periods; and
- 13 • increasing reliability and resilience especially in the face of grid threats such as
14 cyber-attacks and extreme weather events.

15 It is important that the Commission consider whether transmission solutions “are
16 considered by the utility on a fair and consistent basis” as other supply-side and demand-
17 side options as part of its public interest determination.

18 **Q. YOU ALSO MENTIONED THAT THERE ARE RECENT FERC ORDERS THAT**
19 **SPEAK TO STATE ROLES IN REGIONAL AND INTERREGIONAL**
20 **TRANSMISSION PLANNING AND ASSOCIATED COST ALLOCATION.**
21 **COULD YOU PLEASE PROVIDE FURTHER DETAIL ON THIS ISSUE?**

22 A. Yes. Over the past two years FERC has issued a series of orders—Order Nos. 1920, 1920-
23 A, and 1920-B—aimed at advancing multi-value and more proactive regional transmission
24 planning. As part of these orders, the Commission also expanded the state role over
25 regional and interregional transmission. Specifically, state tools and powers discussed in
26 the orders include the authority:

¹⁰³ Ga. Comp R & Regs. 515-3-4-.02(39).

- to collectively develop, and require transmission providers to file for FERC’s consideration, a regional cost allocation formula, and to provide input on any future changes to the cost allocation formula following elements;¹⁰⁴ and
- to inform the planning scenarios required under Order Nos. 1920-A and 1920-B and to request additional long-term planning scenarios.¹⁰⁵

Q. ARE OTHER COMMISSIONS BECOMING MORE ACTIVELY ENGAGED ON TRANSMISSION ISSUES?

A. Yes. States across the country are confronting the three main issues that necessitate cost-effective transmission expansion and modernization to serve customers—aging infrastructure, projected exponential load growth, and extreme weather (and in some regions, wildfire) events. Many commissions have “stepped up their game” with respect to engaging on transmission.

For example, within the SERTP region:

- The South Carolina Public Service Commission recently invited the SERC Reliability Corporation and environmental stakeholders to provide education on the changing needs of the energy system that are impacting the transmission network and best transmission planning practices.¹⁰⁶
- The North Carolina Utilities Commission has been even more proactive, directing its utilities to develop procedures for a more proactive transmission planning through its local transmission process, the CTPC, discussed above. In its comments to FERC on the proposed multi-value planning process, the North Carolina

¹⁰⁴ Order No. 1920-A at P 651.

¹⁰⁵ See, e.g. FERC, *What State Regulators Need to Know About Order No. 1920-B* (updated Apr. 22, 2025), <https://www.ferc.gov/what-state-regulators-need-know-about-order-no-1920-b>.

¹⁰⁶ S.C. Pub. Serv. Comm’n, Notice of Request for Allowable Ex Parte Communication Briefing Filed by Conservation Voters of South Carolina Regarding Transmission Planning Best Practices and Examples of Successful Transmission Planning in Other States, Docket No. ND-2024-44-E (2025); S.C. Pub. Serv. Comm’n, Notice of Request for Allowable Ex Parte Communication Briefing Filed by SERC Reliability Corporation Regarding SERC 101/ERO Enterprise, Transmission Planning, and Load Growth/Changing Resource Mix, Docket No. ND-2024-55-E (2025).

Utilities Commission and the Public Staff – North Carolina Utilities Commission
noted that:¹⁰⁷

Historically in North Carolina, the development of local transmission projects has occurred in response to reliability needs and/or generator needs. As previously discussed, the transmission needs of the utilities were discussed in the IRPs. When a local transmission project was proposed by a utility, the Public Staff would investigate the proposal and make recommendations to the Commission regarding any siting/construction requirements and cost recovery. In general, seldom, if ever, did the Public Staff recommend against a proposed local transmission project. . .

To ensure that customers in North Carolina pay just and reasonable rates that reflect only the costs caused by those customers, planning and investment by utilities in North Carolina must be laser-focused on, and limited to, the needs of the system to serve those customers adequately and reliably. . . Investments in transmission that is unplanned, that does not correlate to resource adequacy, that is not necessary to ensure reliability or sufficiency of import/export capability¹⁰⁸—are not investments that North Carolina customers should have to make and are investments that North Carolina customers cannot afford to make.

Q. ARE THERE ANY OTHER EXAMPLES OUTSIDE OF THE SERTP REGION WHERE STATE COMMISSIONS ARE ACTIVELY ENGAGED ON TRANSMISSION ISSUES?

A. Yes. Idaho Power is one such relevant example. Idaho Power has a similar jurisdictional profile to Georgia Power—it has not joined an RTO and uses bundled rates. Idaho Power’s footprint spans Washington and Oregon and both commissions actively consider high-capacity transmission projects within their IRP processes.¹⁰⁸

¹⁰⁷ *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Re-Filing of Proposed Revisions to Local Transmission Planning Process in Attachment N-1 of Joint OATT, FERC Docket No. ER24-874, at 7, 10-11 (filed Feb. 2, 2024).

¹⁰⁸ Idaho Power, *Our 20-Year Plan* (last visited Apr. 29, 2025), <https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/our-twenty-year-plan/>.

1 **VI. RECOMMENDATIONS**

2 **Q. DO YOU HAVE RECOMMENDATIONS TO ADDRESS THE CONCERNS AND**
3 **DEFICIENCIES THAT YOU HAVE RAISED ABOVE?**

4 A. Yes. I have seven recommendations aimed at evolving Georgia Power's transmission
5 planning processes to reflect proactive, multi-value, and informed planning so that the
6 processes result in cost-effective solutions.

7 **Q. PLEASE DISCUSS YOUR RECOMMENDATIONS AROUND PROACTIVE,**
8 **MULTI-VALUE TRANSMISSION PLANNING.**

9 **Recommendation 1: The Commission should direct Georgia Power to enhance**
10 **transmission planning processes and conduct a proactive and multi-value planning**
11 **analysis.** Georgia Power has said it plans to introduce longer-term planning horizons and
12 scenario planning to its transmission planning procedures. As discussed above, such
13 enhancements are critical to identifying cost-effective grid upgrades, but based on Georgia
14 Power's statements in this proceeding, its plans are currently amorphous. The Commission
15 should help facilitate these efforts by making clear that when conducting transmission
16 planning analyses Georgia Power should: employ at least a 20-year planning horizon,
17 analyze at least three diverse and plausible scenarios, evaluate the full spectrum of
18 transmission benefits, and provide quantitative support for such benefit calculations. The
19 Commission should require Georgia Power to explain and report on its compliance with
20 these directives within each triennial IRP filing and in the annual update and status report
21 filings that the Commission required in the 2022 IRP.¹⁰⁹

22 **Recommendation 2: The Commission should require Georgia Power to provide a**
23 **meaningful analysis of alternative solutions and technology choices.** As part of the
24 triennial IRP filing, the Commission should require Georgia Power to disclose all
25 alternatives considered to each facility included in the plan and provide an accounting of
26 the relative costs and benefits of each. Additionally, the Commission should direct Georgia
27 Power to evaluate for each proposed project (including new, upgraded, and reconductor
28 projects) the use of advanced conductors and grid-enhancing technologies. Georgia

¹⁰⁹ 2022 IRP Order at 18.

1 Power's IRP should identify where such alternative transmission technologies were
2 integrated into the project and, if not, provide an explanation and quantitative data
3 justifying the decision.

4 **Recommendation 3: The Commission should require Georgia Power to report on**
5 **regional and interregional transmission alternatives as part of its IRP and associated**
6 **filings.** Above, I have stressed the value that regional and interregional transmission
7 facilities can provide to Georgia customers. To adequately explore this value, Georgia
8 Power must work collaboratively with its neighbors to develop regional and interregional
9 transmission that will maximize benefits to billpayers and serve as a crucial insurance
10 policy when extreme weather strikes. The Commission should therefore require Georgia
11 Power to report on: (1) which, if any, projects increase interregional transfer capability, (2)
12 the regional projects explored by SERTP as alternatives to local projects, and (3) any
13 interregional projects explored with neighboring utilities that are not SERTP members.
14 This report should account for the full scope of reliability and economic benefits these
15 facilities could provide to Georgia Power billpayers and should be filed along with each
16 triennial IRP filing and in the annual Ten-Year Plan update filings.

17 **Recommendation 4: The Commission should require Georgia Power to provide a**
18 **Southern-wide transmission plan alongside its Georgia-only Ten-Year Plan.** Southern
19 plans transmission across its three-utility system, but in preparing for IRP proceedings,
20 Georgia Power pulls out only the Georgia slice of that plan. It is, as a result, difficult for
21 the Commission and outside observers to understand exactly how the Georgia, Alabama,
22 and Mississippi systems fit together. Throughout my testimony, I've discussed the
23 importance of interstate and interregional transmission. Southern deserves credit for
24 planning transmission collectively across its large footprint, which can maximize energy
25 resources and minimize development costs. But the Commission should be able to visualize
26 the *entire* Southern network so it can more accurately assess whether Georgia Power is
27 planning effectively and taking advantage of the ties between sister companies to serve
28 Georgia customers. Accordingly, the Commission should require Georgia Power to file a
29 Southern-wide transmission plan for informational purposes as part of its triennial IRP
30 filing.

1 **Q. PLEASE DISCUSS YOUR RECOMMENDATIONS AROUND INFORMED**
2 **TRANSMISSION PLANNING.**

3 **Recommendation 5: The Commission should direct Georgia Power to establish a**
4 **Georgia Transmission Advisory Group to inform transmission planning processes.**

5 Because the regional SERTP process offers an insufficient forum for stakeholder
6 engagement, interested parties need a chance to react to proposed local plans *before* they
7 are baked into the regional plan. The Commission should therefore direct Georgia Power
8 to establish a Georgia Transmission Advisory Group (“GTAG”) that gives stakeholders an
9 avenue to suggest scenarios, review planning assumptions, propose alternative
10 transmission solutions, and offer other recommendations. The GTAG should be comprised
11 of Public Staff, customer representatives, generation developers, environmental groups,
12 and other interested stakeholders. Georgia Power should also use this process to educate
13 participants about how Georgia Power’s local transmission plan integrates with the broader
14 Southern footprint—and how that footprint intersects with neighboring states and regions.

15 **Recommendation 6: The Commission should direct Georgia Power to provide**
16 **additional cost transparency.** In Technical Appendix Volume 3 of this IRP, Georgia
17 Power redacts the estimated costs of all the projects in its Ten-Year Plan. If ratepayers are
18 going to bear the costs of new and upgraded transmission, they deserve to have ready access
19 to that financial data, so they can make an informed judgment about the cost-benefit ratio
20 of Georgia Power’s proposed projects. Accordingly, the Commission should direct Georgia
21 Power to include the planning-level cost estimates of each project in its Ten-Year Plan,
22 both as part of the triennial IRP filing and in the annual update filings. Crucially, the public
23 should be able to view this information *without* having to sign a non-disclosure agreement.

24 **Recommendation 7: The Commission should direct Georgia Power to provide post-**
25 **event reports after extreme weather events.** As noted above, although Georgia Power is
26 taking the viewpoint that additional connections to neighboring regions are not needed,
27 that sentiment is not shared by others, including NERC. To evaluate these positions, it
28 would be helpful if the Commission and stakeholders have access to information about
29 previous events to determine whether existing capacity will be sufficient in the future such
30 as the analysis provided in the NERC-FERC Report. Accordingly, the Commission should

1 direct Georgia Power to compile and file for Hurricane Helene and every future extreme
2 weather event, a post-event report that includes information on: (1) generator performance
3 in the Southern BAA and reasons for nonperformance, (2) import/export quantity and
4 pricing from/to neighboring BAAs, (3) import/export constraints including reasons for
5 such constraints (e.g. neighboring authority did not have excess capacity available,
6 transmission constraints limited import capability, etc.).

7 **Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS?**

8 A. Yes. Given the substantial changes on the horizon for Georgia Power—and the country as
9 a whole—I recommend and encourage **the Commission to foster more opportunities to**
10 **collaborate with commissioners in neighboring states on transmission issues.** Because
11 the Southeast does not have a regional organization to convene state regulators—such as
12 the Organization of MISO States, the Organization of PJM States, Inc., the Western
13 Interstate Energy Board, or the Western Conference of Public Service Commissioners—
14 the Commission may need to take a proactive role to foster avenues for such
15 communication.

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

17 A. Yes.

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**STATE OF GEORGIA
BEFORE THE
PUBLIC SERVICE COMMISSION**

In Re:)	
)	Docket No. 56002
Georgia Power Company's)	
2025 Integrated Resource Plan)	
)	
And)	
)	
Georgia Power Company's 2025 Application)	
for the Certification, Decertification, and)	Docket No. 56003
Amended Demand-Side Management Plan)	
)	

EXHIBIT AP-1

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EMPLOYMENT HISTORY:

David Gardiner and Associates, Clarendon, VA

Vice President for Clean Energy

April 2022–present

- Provide strategic, programmatic, and management support to Americans for a Clean Energy Grid, a multi-stakeholder organization that educates and advocates for the expansion, modernization, and integration of the high-capacity transmission network to improve reliability and resilience and increase access to cleaner energy resources.
- Advocate for federal and state policies to improve corporate access to clean energy and to facilitate cost-effective and equitable transportation decarbonization initiatives.
- Educate public and private entities on energy infrastructure investment, decarbonization technologies, and tax incentives and federal funding opportunities to help advance greenhouse gas emission reductions.
- Assist with business development and supervise and manage the firm's Clean Energy team.

Office of the People's Counsel for the District of Columbia, Washington, DC

Litigation Supervisor

September 2021–April 2022

Senior Assistant People's Counsel

June 2018–September 2021

- Managed a complex portfolio of litigated cases, and regulatory and policy matters before PJM, state and federal agencies, and appellate courts with an emphasis on ensuring safe and reliable utility service at just and reasonable rates, promoting equity considerations, and advancing the District of Columbia (DC) government's robust decarbonization goals. Major cases include: serving as lead counsel in an electric distribution rate case in which the utility sought approval to transition to a multiyear rate plan with performance incentive mechanisms; drafting a petition to address community solar billing and metering issues; advocating for the public interest in proposed energy efficiency, transportation electrification, and infrastructure improvement programs; advocating for transparent and cost-effective market rules and policies in PJM's stakeholder processes; drafting comments to address Federal Energy Regulatory Commission (FERC) rulemaking proposals and comments and protests to FERC orders revising PJM's governing documents; serving as the Secretary of the DC Public Service Commission's Pilot Project Governance Board; participating in stakeholder meetings addressing grid modernization, energy efficiency, and electrification initiatives.
- Provided issue briefings and strategic advice to senior management and assisted in developing the agency's litigation, legislative, and policy positions.
- Supervised, mentored, and trained staff attorneys and ensured that federal, state, and court dockets pertaining to utility-related matters impacting DC consumers were staffed appropriately.
- Drafted and reviewed legal and informational materials to support the agency's mission and policies, including motions, briefs, comments, petitions, testimony, discovery, settlement agreements, public fact sheets, web articles, and press releases.
- Supervised and managed litigation teams of in- and out-of-house attorneys and technical experts.
- Managed consultant contracts and assisted the Agency's Technical Division in procurement processes.
- Conducted outreach to elected and appointed officials, civic and neighborhood associations, labor organizations, environmental and advocacy groups, and other stakeholders on pending cases and emerging issues in the energy industry.
- Served as the Freedom of Information Act (FOIA) Officer from June 2018-November 2021.

Spiegel & McDiarmid LLP, Washington, DC

Associate

September 2010–May 2018

- Advocated for the interests of governmental authorities and public entities before appellate courts and federal and state agencies, including FERC, the U.S. Environmental Protection Agency, and Federal Aviation Administration, by developing litigation strategies, drafting procedural and substantive pleadings, engaging in settlement negotiations, cross-examining witnesses at hearings, drafting and reviewing discovery, reviewing and revising expert testimony, and collaborating with technical consultants. Work included: litigating gas and electric cases before state public service commissions; representing municipal utility and state agency interests in public utility merger proceedings; representing client interests in an arbitration proceeding concerning power purchase costs; representing client interests in settlement negotiations before FERC Administrative Law Judges; and drafting comments for municipal utilities on FERC's electric and merchant gas transmission policies.
- Co-founded and contributed to the public interest energy and environmental blog, consideringthegrid.com.
- Counseled clients on the application of and developments in complex regulatory and constitutional laws and policies.
- Drafted, negotiated, and interpreted contracts for municipal utilities and airport operators.
- Mentored, issued assignments to, and reviewed work product from junior associates.
- Directed and managed secretarial and paralegal support.

Law Clerk

May–July 2008

Great Lakes Commission, Ann Arbor, MI

Great Lakes Commission-Sea Grant Fellow

June 2009–July 2010

- Facilitated consensus building, information exchange, and policy development for the Great Lakes Wind Collaborative—a multi-sector and binational coalition dedicated to facilitating the sustainable development of onshore and offshore wind in the Great Lakes region—and the Great Lakes Panel on Aquatic Nuisance Species—a federally organized panel with binational membership dedicated to preventing the spread of new, and controlling existing, aquatic invasive species in the Great Lakes.
- Drafted resolutions, comments on proposed rulemakings, and legislative testimony on issues of regional environmental and economic significance.
- Developed grant agreements for, and addressed public comments on, the implementation of the Great Lakes Restoration Initiative, a \$475 million Congressionally approved program.
- Organized and conducted regional stakeholder workshops and webinars.

Academy of Natural Sciences, Philadelphia, PA

Educator and Overnight Program Manager

September 2001–June 2005

- Designed and conducted classes and teacher workshops on natural history and environmental topics.
- Created curricula, hired and managed staff, and developed and maintained an annual budget for the museum's overnight program.

EDUCATION:

The University of Michigan Law School, Ann Arbor, MI

Juris Doctor

December 2008

Drexel University, Philadelphia, PA

Master of Science in Environmental Policy

June 2005

Case Western Reserve University, Cleveland, OH
Bachelor of Arts in Biology and Environmental Studies, *magna cum laude*
Minors in Chemistry and English

May 1999

SELECT PUBLICATIONS:

Americans for a Clean Energy Grid, *State Policies to Advance Transmission Modernization and Expansion* (2024).

David Gardiner and Associates, *Options for Decarbonizing Cold-Weather Higher Education Campus Heating Systems* (2024).

David Gardiner and Associates, *Consumer Advocates of the PJM States' Transmission Handbook*, CAPS, (2024).

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Lisa Dowden, Anjali Patel, Latif Nurani, *Alternative Resource Adequacy Mechanisms and Where Capacity Markets Go From Here*, American Public Power Association Pre-Conference Workshop (October 2014).

Robert A. Jablon, Anjali G. Patel, and Latif M. Nurani, *Trinko and Credit Suisse Revisited: The Need for Effective Agency Review and Shared Antitrust Responsibility*, 34 Energy L.J. 627 (Fall 2013).

National Association of Local Government Environmental Professionals, *Cultivating Green Energy on Brownfields* (2012).

Anjali G. Patel, Katherine Glassner-Shwayder, and Tim Eder, *Halting the Invasion: Maintaining the Health of the Great Lakes and Mississippi River Basins by Preventing Further Exchange of Aquatic Invasive Species*, 12 Environmental Practice 342 (2010).

Anjali Patel, *The Role of the Great Lakes-St. Lawrence Seaway Ports in the Advancement of the Wind Energy Industry*, The Great Lakes Commission (2010).

BAR ADMISSIONS

U.S. Court of Appeals, D.C. Circuit	Admitted 2015
U.S. Court of Appeals, Second Circuit	Admitted 2018
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CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of Anjali Patel on behalf of Georgia Interfaith Power & Light and Southface Energy Institute** was filed with the Public Service Commission in Dockets No. 56002 and 56003 by electronic delivery on the 2nd of May, 2025. An electronic copy of the same was served upon all parties listed below by electronic mail as follows:



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