

BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:	:	
	:	
GEORGIA POWER COMPANY’S	:	DOCKET NO. 56002
2025 INTEGRATED RESOURCE PLAN	:	
UPDATE	:	
	:	
AND	:	
	:	
GEORGIA POWER COMPANY’S 2025	:	DOCKET NO. 56003
APPLICATION FOR THE	:	
CERTIFICATION,	:	
DECERTIFICATION,	:	
AND AMENDED DEMAND-SIDE	:	
MANAGEMENT PLAN	:	

DIRECT TESTIMONY OF TED THOMAS
ON BEHALF OF CLEAN ENERGY BUYERS ASSOCIATION

May 2, 2025

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I. Introduction and Summary of Recommendations.

Q: Please state your name.

A: My name is Ted Thomas.

Q: By whom are you employed and in what position?

A: I am an independent consultant with the firm that I founded, Energize Strategies.

Q: Please describe your current role and your relevant professional experience.

A: My prior employment includes serving as the Chairman of the Arkansas Public Service Commission from January 2015 to September 2022. In that role, I led the state agency responsible for utility regulation in Arkansas and was the President of the Organization of MISO states, among other things. I have also previously served as a lawyer, a member of the Arkansas House of Representatives, a budget director for Governor Mike Huckabee, a consultant and law partner, an Administrative Law Judge, and a prosecutor.

I earned a Bachelor of Arts with High Honors in Political Science from the University of Arkansas in 1986. I was awarded my Juris Doctorate from the University of Arkansas School of Law in 1988.

Q: Have you previously provided testimony before the Georgia Public Service Commission?

A: No, I have not.

Q: Have you previously provided testimony in any proceedings before other regulatory commissions?

A: Yes. I filed testimony before the Indiana Utility Regulatory Commission in Cause No. 46183.

1 **Q: Please describe Clean Energy Buyers Association (CEBA).**

2 A: CEBA is a business trade association that activates a community of energy buyers and
3 partners to advance low-cost, reliable, carbon emissions-free global electricity systems.
4 CEBA's more than 400 members represent more than \$20 trillion in market capital and
5 include institutional energy customers of every type and size – corporate and industrial
6 companies, universities, and cities, as well as project developers and service providers.
7 CEBA's membership includes one-fifth of the Fortune 500 companies and some of the
8 largest buyers of clean energy that conduct business operations across the United States
9 and in Georgia, including customers of Georgia Power Company (Georgia Power).
10 CEBA's corporate and industrial members include companies across a variety of sectors
11 including information technology, data centers, auto manufacturing, clean energy
12 manufacturing, heavy industry, food and beverage manufacturers, financial institutions,
13 restaurants, hotels, retail chains, and more. CEBA's members have ambitious clean energy
14 commitments, and many of these members now consider, if not prioritize, their ability to
15 access clean energy when determining where to locate new facilities and which existing
16 facilities to expand.

17 **Q: What is the purpose of your Direct Testimony?**

18 A: The purpose of my Direct Testimony is to discuss the risks that regulators and utilities
19 manage on behalf of utility customers and how transmission planning and deployment can
20 help mitigate that risk, and to provide three recommended actions the Commission should
21 order Georgia Power to take in this proceeding.

1 **Q: Please summarize your recommendations to the Commission.**

2 **A:** I recommend that the Commission:

3 1. Direct Georgia Power to conduct and submit a study on the potential benefits of joint
4 transmission planning with Alabama Power and Mississippi Power that reflects the
5 integrated operations of the Southern Company pool. This planning should:

6 a. Use multiple future scenarios to capture a range of risks;

7 b. Consider multi-value benefit streams (e.g., economic dispatch, reserve margins,
8 reliability); and

9 c. Include a cost allocation framework to ensure costs are roughly commensurate
10 with benefits across jurisdictions.

11 2. Direct Georgia Power to incorporate utility-scale and customer-driven clean generation
12 resource deployment into its transmission planning assumptions, including various
13 levels of deployment. This should include:

14 a. Utility-scale solar in the IRP;

15 b. Anticipated deployment under the CARES customer subscription program and
16 the proposed Customer Identified Resource option; and

17 c. Consideration of geographic and grid access factors in siting analysis.

18 3. Direct Georgia Power to conduct and submit a study of the potential benefits of
19 increasing the interregional transmission transfer capability between its balancing
20 authority and adjacent regions, consistent with North American Electric Reliability
21 Corporation's (NERC) recommendations. The study should:

- 1 a. Evaluate current and potential capacity to import/export power during extreme
2 events;
3 b. Identify constraints and needed upgrades; and
4 c. Include coordination with sister companies and adjacent balancing authorities.

5 **II. Regulator as Risk Manager**

6 **Q: What will you address in this section of your testimony?**

7 A: In this section of my testimony, I will address risks that have to be managed by regulators
8 and utilities and how transmission and transmission planning can perform a key role in risk
9 mitigation.

10 **Q: Do Company witnesses in support of the IRP filing address risks that need to be**
11 **managed?**

12 A: Yes. The Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney,
13 Michael B. Robinson, and Francisco Valle discusses risk extensively.¹ Additionally, the
14 Direct Testimony of Jennifer S. McNelly and Robert W. Mitchell III focuses on
15 environmental compliance, which is a key risk factor.²

16 **Q: How do you think regulators should think about risk?**

17 A: I think the regulator's role is analogous to the role of the manager of a pension fund. The
18 assets are owned by the utility for the benefit of customers. The utility earns a return on the
19 total investment, but the value of the assets flows through to the customers. A regulator

¹ Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle at 17-30.

² The Direct Testimony of Jennifer S. McNelly and Robert W. Mitchell III addresses environmental policy risk and need for flexibility to address that risk throughout the testimony.

1 should seek to manage those assets in a way that creates the most value for customers. I
2 break economic risk into four broad categories:

- 3 1. Changing prices.
- 4 2. Changing federal and state policy.
- 5 3. Changing technology.
- 6 4. Reliability and resilience risks.

7 **Q: How should regulators think about the risk of changing prices?**

8 A: The key price that is subject to changes in the utility industry is the price of natural gas.
9 The price of natural gas is volatile and difficult to predict. A regulator wants exposure to
10 natural gas for the benefit of customers when its price is low but should diversify the
11 portfolio to account for times when the price of natural gas is high. During the expected
12 life of generation assets, it is probable that there will be periods of both high and low natural
13 gas prices. Georgia Power currently generates 40% of its electricity mix from natural gas,
14 which makes customers very vulnerable to a gas price spike.

15 A second key price concept is what technology experts refer to as the “S” curve,³ a
16 graphical presentation of the rate of adoption of new technologies. Adoption of new
17 technologies is not linear; it starts out slowly then rapidly accelerates and then levels out.
18 This happened with automobiles, washing machines, microwave ovens, flat screen
19 televisions and nearly every consumer technology, and also happens with energy

³ A good description of the “S” curve and technology innovation can be found at
<https://medium.com/groveventures/technologys-favorite-curve-the-s-curve-and-why-it-matters-to-you-249367792bd7>.

1 technologies. Every new technology starts out as more expensive, but as production scales
2 the price comes down. Accordingly, when thinking about the price of new generation
3 technologies that are beneficial to customers but potentially more expensive, regulators
4 should expect prices to come down over time as adoption increases.

5 **Q: How should regulators think about the risk of changing federal and state policy?**

6 A: As discussed extensively by the Company's witnesses,⁴ environmental policy is a key risk
7 factor that can change the value of the generation portfolio that flows through to customers.
8 Regardless of a regulator's view on the proper balance between cost and environmental
9 protection, during the life of a generation asset there are likely to be times of more
10 aggressive and less aggressive environmental regulation. Other federal or state regulations
11 can also impact the value of that generation portfolio. A regulator should consider how to
12 hedge policy change risks while managing the portfolio to maximize customer value.

13 **Q: How should regulators think about the risk and reward of technology changes?**

14 A: Technology solves and changes our policy challenges over time. A regulator should want
15 its customers exposed to the potential benefits of innovation and technology change.
16 Technology adoption comes with risk in that not all potential new technologies reach their
17 intended goal or are available at a price that provides value. A regulator should consider
18 all of the possible technologies that might emerge and think about how the regulatory
19 landscape would need to change if any of those technologies emerge as a winner. In the
20 electric utility industry, the pace of change is different because of the long useful life of

⁴ The Direct Testimony of Jennifer S. McNelly and Robert W. Mitchell III addresses environmental policy risk and need for flexibility to address that risk.

1 the assets. Regulators should also consider the impact of the “S” curve on technology prices
2 and understand that experimentation with new technologies comes with some cost risk, but
3 that cost is part of how innovation happens.

4 **Q: How should regulators think about reliability and resilience risks?**

5 A: Reliability is always a top priority, as is resilience, which I view as the ability to recover
6 quickly from a reliability issue. These are operational issues, and it is also difficult to apply
7 benefit-cost analysis to reliability and resilience. The regulator’s role should be focused on
8 oversight of utility operations. As is discussed below, planning for a more robust grid can
9 mitigate reliability and resilience risks.

10 **Q: You referenced the comprehensive nature of the Company witnesses with respect to**
11 **risk that needs to be managed. Are there any risks that you think merit more attention**
12 **from the Company witnesses?**

13 A: Yes. I think the risk of gas plants operating at low capacity factors in later years is a risk
14 that merits more consideration when evaluating new gas-fired generation.

15 **Q: Why is the capacity factor of a resource important?**

16 A: A capacity factor represents the percentage of hours during a given year that a generation
17 unit operates or is expected to operate. Cost comparisons used by utilities and regulators to
18 evaluate generation resources are typically based on an expected capacity factor. If a
19 resource operates at a lower capacity factor than projected, it means that there are fewer
20 hours of operation over which to spread fixed costs. For example, if a unit with a projected
21 40% capacity factor for a given year only runs 20% of the year, then the fixed costs for that
22 year are double what they were projected to be for that year, on a \$/MWh basis.

1 **Q: Do you offer an opinion regarding the need for any new gas units?**

2 A: No, I do not. I am just calling attention to what I view as an often-overlooked risk factor
3 with respect to new natural gas units.

4 **Q: How can the IRP process mitigate these risks?**

5 A: A diverse generation portfolio and a thoughtful adoption of new technology are both
6 critical to mitigating the four main economic risks described above. Aggressive
7 deployment of renewables, particularly when a utility has a low level of renewable
8 penetration as Georgia Power does, can mitigate both environmental policy risk and cost
9 risk because the unsubsidized all-in costs of solar and wind generation are cost competitive
10 with natural gas with a reasonable gas price forecast.⁵ When renewable resources plus
11 integration costs are roughly equivalent to natural gas units on an all-in cost, life-of-the-
12 unit basis, aggressive adoption of renewables is a cost-free hedge against high natural gas
13 prices.

14 **Q: What do you recommend with respect to this issue?**

15 A: The Commission should carefully consider ways to mitigate the risk of changing prices,
16 changing environmental policy, and changing technology on consumer costs.

17 **III. Transmission as Risk Mitigator**

18 **Q: What will you address in this section of your testimony?**

19 A: In this section of my testimony, I will address how a well-planned and developed
20 transmission grid can mitigate risks faced by utilities and regulators.

⁵ See Lazard Levelized Cost of Energy Analysis. <https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-vf.pdf>.

1 **Q: What is transmission and its fundamental purpose?**

2 A: Transmission is the wires from generating units to the substation, at which point the
3 distribution system begins. Its fundamental purpose is to move power from the generation
4 units to the circuits that deliver power to homes and businesses. From an economic
5 perspective, transmission expands the geographic area in which a generator can reliably
6 serve load.

7 **Q: How does transmission mitigate risk?**

8 A: The transmission grid serves all sources of generation and provides flexibility to the system
9 so that the system economics can respond to changes in prices and environmental policy
10 that are among the core drivers of the value of the generation fleet.

11 **Q: How do changes in the variable costs of generation influence the operation of the grid?**

12 A: The system is dispatched such that the lowest cost generation resource that can reach the
13 load reliably is used to serve that load across the entire Southern Company Balancing
14 Authority without regard to ownership of generation or location of load. As load increases,
15 the next available generation resource that is not yet being used, that is capable of ramping
16 up, and that is the least expensive, is used to serve that additional load. As the load
17 decreases, the most expensive generation capable of ramping down is ramped down. It is
18 important to understand that in this context, only the variable cost of generation is
19 considered.⁶ The fixed costs are sunk costs that will be incurred whether or not the
20 generation unit is operating. This is known as security-constrained economic dispatch. The

⁶ Economic dispatch is described in more detail on page 148 of the IRP document.

1 dispatch is “security constrained” in that the list of generators competing to be the least
2 expensive is limited to those generators which the grid can accommodate consistent with
3 reliability standards.

4 **Q: Why is the distinction between fixed costs and variable costs so important in economic**
5 **dispatch?**

6 A: The system is dispatched based on variable costs only, although customers remain
7 responsible for all prudently incurred costs. Because renewables have no variable costs,
8 they are always among the least expensive resources in a dispatch determination. Even a
9 wind turbine made of gold would be the lowest cost unit for dispatch purposes, even though
10 it would be very expensive when computing all in costs over the life of the asset, because
11 economic dispatch is based on variable costs only.

12 **Q: How does increased transmission impact economic dispatch?**

13 A: Because transmission increases the geographic reach of generation assets, additional
14 transmission makes more resources available for consideration in the economic dispatch,
15 creating more instances where the transmission enables generation savings.

16 **Q: How can opportunities for savings be identified?**

17 A: This is one of the purposes of good transmission planning. Utilities and regulators should
18 aggressively seek out opportunities to strengthen the grid that are paid for by savings in
19 generation costs. Like renewable generation at low levels of penetration, this can be a cost-
20 free hedge against risk. Transmission planning is discussed in more detail below.

1 **Q: How does transmission mitigate risk?**

2 A: Variable cost inputs will change the economic dispatch of generation resources, and
3 expanding transmission enables more of the generation portfolio to be available, thereby
4 working with portfolio diversification to mitigate risks. Additionally, a higher level of
5 deliverability of generation across the Southern Company Balancing Authority allows the
6 same level of reliability to be achieved with a lower reserve margin. In this way,
7 transmission should be viewed as a resource adequacy asset because it enables more
8 geographic diversity of generation resources.

9 **Q: What do you recommend with respect to this issue?**

10 A: I recommend that the Commission view transmission expansion as a tool to mitigate risks
11 for customers.

12 **IV. Transmission Planning**

13 **Q: What will you address in this section of your testimony?**

14 A: In this section of my testimony, I will address how a well-planned and developed
15 transmission grid can mitigate risks faced by utilities and regulators.

16 **Q: Why is transmission planning important?**

17 A: The transmission grid is a network, and networks must be planned. They do not emerge
18 from markets as happens with consumer products.

19 **Q: In your view, what are the elements of optimal transmission planning?**

20 A: Optimal transmission planning consists of three key elements:

21 1. Use of multiple planning scenarios.

22 2. Simultaneous consideration of multi-value benefit streams.

1 3. A long enough planning horizon to be proactive with respect to expected system
2 change.

3 **Q: Why is it important to use multiple planning scenarios?**

4 A: Multiple planning scenarios focusing on mitigating different risks can identify transmission
5 projects that create value in a variety of different circumstances. Commonly used system
6 modeling tools can simulate the economic dispatch described above over a significant
7 period. High and low natural gas price scenarios, higher and lower emissions restrictions,
8 and varying prices for new generation technologies can all be modeled to identify value
9 that can be captured from deployment of new transmission.

10 **Q: Why is simultaneous consideration of multi-value benefit streams important?**

11 A: The key planning criterion for transmission planning is compliance with NERC reliability
12 standards, but this criterion should be optimized with other criteria including energy
13 benefits from economic dispatch as described above, reserve requirement benefits as
14 described below, and optimization of smaller reliability projects and larger projects that
15 solve multiple reliability problems, including resolving congestion constraints that result
16 in higher costs for customers. Optimal transmission planning involves the search for
17 opportunities in which transmission can be developed such that expected generation
18 savings pays for all or part of the transmission project. Building a more robust grid paid
19 for to the maximum extent possible by savings in generation costs can enhance reliability
20 and resilience without engaging in the difficult process of trying to monetize resilience and
21 reliability benefits.

1 **Q: Why is the planning horizon important?**

2 A: In order to be more proactive with respect to expected system changes, a longer planning
3 horizon is needed. Although a longer planning horizon necessarily adds to the risk of
4 inaccurate assumptions, at a time of rapid load growth there is greater risk in failing to meet
5 expected future demand. Transmission is itself a long-lived, multi-decadal asset; the
6 benefits of transmission tend to increase over time while its costs decrease as transmission
7 assets are depreciated. Significant load growth mitigates the risk of excessive transmission
8 investment because of the difficulty of forecasting during a longer time horizon. Given the
9 long lead times needed to plan and build transmission projects, utilities and regulators can
10 increase their ability to be proactive, rather than reactive, by increasing their planning
11 horizons.

12 **V. Joint Transmission Planning Among Georgia Power, Alabama Power, And**
13 **Mississippi Power**

14 **Q: What is the Southern Company Pool?**

15 A: The Southern Company Pool is an arrangement between Georgia Power, Alabama Power,
16 and Mississippi Power to share generation resources. The economic dispatch discussed
17 above is done on a system-wide basis using the generation assets of each of the Southern
18 Company operating companies. These transactions are governed by the Southern Company
19 System Intercompany Interchange Contract (IIC). Because transactions between the
20 operating companies are sales for resale, the IIC is a Federal Energy Regulatory
21 Commission (FERC) approved tariff. A complete description of the pooling arrangement
22 appears in the Georgia Power IRP document, Attachment G.

1 **Q: What are the benefits to Georgia Power customers of participating in the pool?**

2 A: Those benefits are enumerated in the IRP Main Document on pages 145-146. Among the
3 benefits are access to lower cost generation when it is available and a lower reserve margin
4 for each of the operating companies because of the sharing of resources.

5 **Q: How do “sales” to and from Georgia Power, Alabama Power, and Mississippi Power**
6 **occur?**

7 A: These “sales” occur as part of the economic dispatch process. The entire Southern
8 Company Balancing Authority is dispatched as if it were a single entity without regard to
9 state boundaries or the boundaries between Southern Company operating companies and
10 municipal and cooperative utilities. There are two parallel universes: first is the physical
11 system that delivers electricity to all of the customers in the balancing authority without
12 regard to political boundaries. Second is the economic and accounting system that allocates
13 the cost to customers based on ownership of the assets and the assigned service territories
14 of each entity that provides electric energy in the Southern Company Balancing Authority.
15 Each operating company, municipal utility, and cooperative’s load is measured each hour,
16 as are their generation assets. The load and generation of the total balancing authority will
17 always be equal, but in any given hour a utility’s load may exceed its generation that is
18 online or be less than its generation that is online. Those utilities with excess generation
19 during that hour are deemed to have “sold” that generation to those utilities that have more
20 load than generation online.

1 **Q: Is this process fair to both the “buyer” and the “seller”?**

2 A: Yes. The lowest cost resources of each utility stay with that utility and their customers that
3 have cost responsibility for that generation. Only the excess generation that a utility does
4 not need to serve its own customers is “sold” through the pool. The excess that is “sold”
5 are the more expensive resources that were not needed to serve that utility’s load. Thus,
6 this arrangement is not a detriment to the owning utility or its customers. Similarly, the
7 “buyer” of the excess generation will only “buy” generation if it is less expensive than any
8 other generation available to that utility. Thus, it is the lowest cost alternative to the buying
9 utility and its customers.

10 **Q: Does the IIC reference transmission service?**

11 A: Yes, in two places. First, FERC requires separation between power market participants and
12 transmission operations within the same company so that ownership and operation of the
13 transmission system is not used to favor the owning company’s generation resources. The
14 IIC contains a provision to comply with these rules, which are referred to as “standards of
15 conduct.” Second, the IIC provides that transmission service requests should be made
16 through Southern Company’s Open Access Transmission Tariff so that all participants,
17 including Southern Company operating companies, have access to the grid under the same
18 terms and conditions.

19 **Q: Does the IIC reference transmission planning?**

20 A: No, it does not.

1 **Q: Does the Georgia Power IRP document describe how Georgia Power conducts**
2 **transmission planning?**

3 A: Yes, it does. Page 111 of the IRP Main Document describes the transmission planning
4 process and principles.

5 **Q: What is the geographic scope of transmission planning conducted by Georgia Power**
6 **and presented in the IRP?**

7 A: The service territories of the Integrated Transmission System (ITS), which includes
8 Georgia Power, Georgia Transmission Corporation, MEAG Power, and Dalton Utilities
9 defines the geographic scope of transmission planning conducted by Georgia Power.

10 **Q: Do the IRP documents and testimony describe a transmission planning process**
11 **designed to maximize the benefits of the Southern Company Pool to Georgia Power**
12 **customers?**

13 A. No. While Georgia Power and Southern Company clearly recognize the benefits of joint
14 generation planning and dispatch, they do not seem to recognize the potential benefits to
15 customers of jointly planning their transmission systems. While transmission planning for
16 Georgia Power is performed at the Southern Company level, that does not necessarily mean
17 that the transmission systems of the operating companies are jointly planned and Georgia
18 Power has given no indication that the systems are jointly planned. Accordingly, it is my
19 recommendation that Georgia Power be directed to study and report to the Commission
20 regarding the potential value of jointly planning transmission with its sister operating
21 companies (Alabama Power and Mississippi Power) as they already do with respect to
22 generation assets through the pooling agreement. Furthermore, Georgia Power should

1 study the benefits of developing a system of cost sharing that makes the cost of
2 transmission projects roughly commensurate with the benefits achieved for each operating
3 company, rather than based only on the location of the transmission facility. As discussed
4 above, this transmission planning should use multiple planning scenarios, consider all
5 benefit streams, and have a long enough planning horizon to be proactive with respect to
6 expected system change.

7 **Q: How does the Georgia ITS transmission planning process share costs among its**
8 **participating entities?**

9 A: My understanding is that agreement that a facility is needed by each ITS entity is a
10 prerequisite for any sharing of costs. Each entity owns the transmission facilities located
11 within their service territory. A 5-year rolling average of load ratio share usage of the assets
12 is computed and compared to each entity's share of the remaining balance to be recovered
13 on the transmission assets. If the load ratio share and each entity's share of the total
14 unrecovered investment are equal, the system is said to be in parity. If not in parity,
15 payments are made by entities with more load share than investment share to the other
16 entities until parity is restored.⁷ In my opinion this is a reasonable method of cost sharing
17 and would be a good starting point for discussions among the Southern Company operating
18 companies of a cost sharing mechanism.

⁷ <https://www.energy.gov/sites/prod/files/2015/03/f20/Paper%20Joint%20Transmission%202009%20update.pdf>.

1 **VI. Transmission Planning for Clean Generation Resource Deployment**

2 **Q: Does the Georgia Power IRP include significant expected deployment of utility scale**
3 **renewable energy resources?**

4 A: Yes. Georgia Power expects significant deployment of new renewable generation facilities.
5 The Company has proposed to procure up to 4,000 MW of additional renewables by 2035.

6 **Q: Does the Georgia Power IRP also propose methods by which large customers can**
7 **procure dedicated clean energy resources?**

8 A: Yes. Georgia Power has proposed a new “Customer Identified Resource” option for its
9 Clean and Renewable Energy Subscription (CARES) program that will allow large
10 customers to work with a third-party developer and subscribe to specific clean energy
11 resources through the utility. CEBA’s other witnesses in this proceeding, Ms. Priya Barua
12 and Mr. R. Brent Alderfer, address the Customer Identified Resource proposal.

13 **Q: What are the key components of siting solar generation?**

14 A: High irradiation, flat and reasonably priced land, and access to the grid.

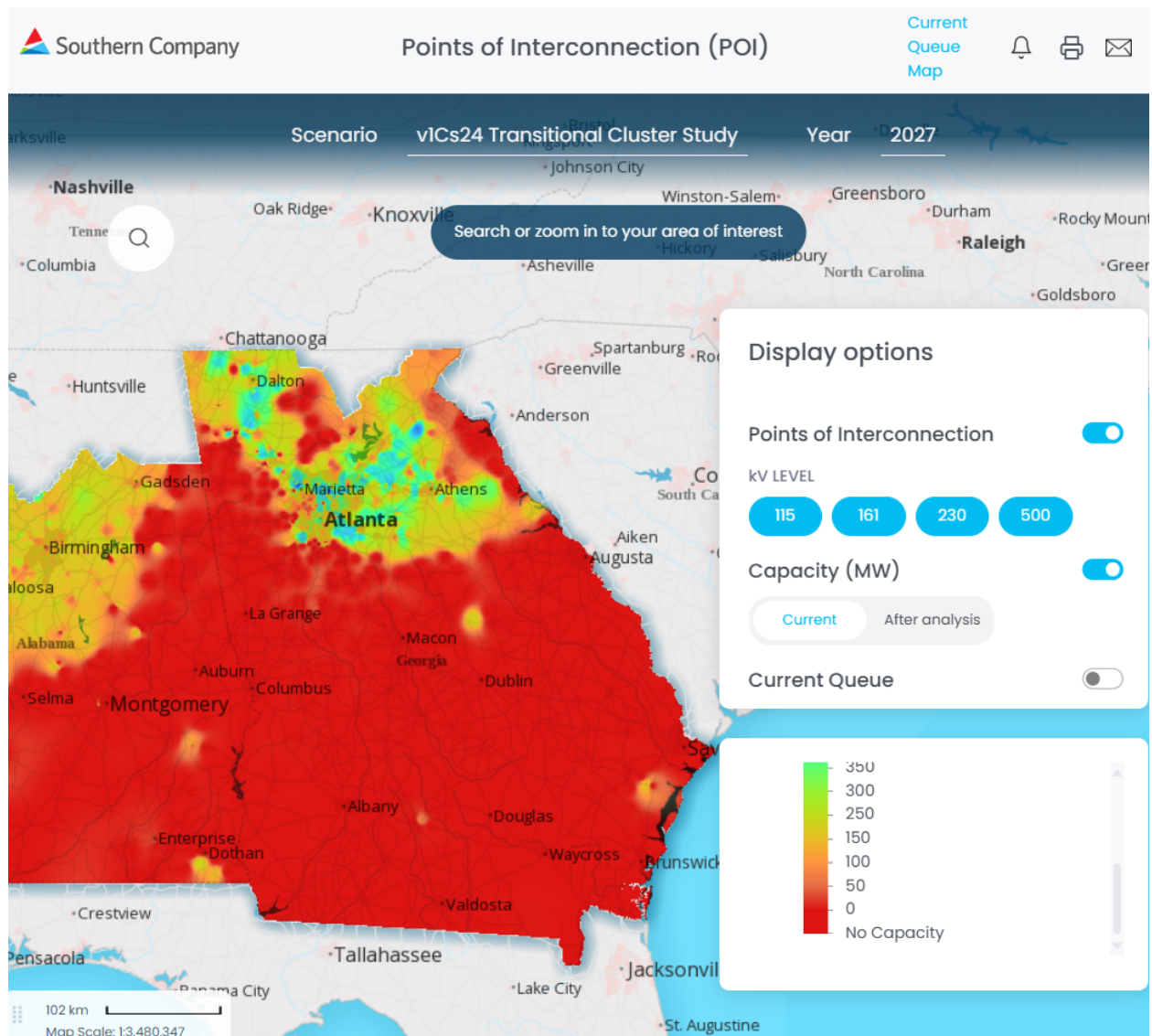
15 **Q: Does Georgia Power have significant experience with solar resources in the State of**
16 **Georgia?**

17 A: Yes. Georgia Power owns and purchases significant solar resources in Georgia.

1 **Q: Do solar and other clean energy developers currently face interconnection injection**
2 **capacity limitations?**

3 **A:** Yes. Southern Company recently released an online hosting capacity map tool that it calls
4 Sight.⁸ The Sight tool uses color coding to show the amount of interconnection capacity
5 available at different locations for different years in the future, with red showing no or very
6 little available capacity and dark blue showing 3,000 MW of injection capacity. As can be
7 seen in the screenshot below for 2027, there is very little or no injection capacity available
8 in most areas of Georgia by geography. Substantial transmission development will be
9 needed in most areas of the state to facilitate continued cost-effective development of solar
10 and other clean energy resources.

⁸ <https://sight.southernco.com/poi-analysis-map>.



1
2
3 **Q: How should siting of solar and other clean energy resources be accounted for in**
4 **transmission planning?**

5 **A:** I recommend that the benefits of additional solar and clean energy resources be considered
6 as one of the benefits of proposed transmission projects. Georgia Power's experience with
7 solar facilities should inform these planning practices and the quantity of expected

1 renewable resources should include both Georgia Power's planned renewable procurement
2 as well as the potential clean energy deployment that will result from the CARES program,
3 the Customer Identified Resource option, and other customer clean energy programs. This
4 way the grid will be ready for expected clean energy deployment from all sources.

5 **Q: Has Georgia Power provided any analysis of the transmission implications of larger**
6 **amounts of renewable deployment in its IRP documents?**

7 A: No. At hearing, Georgia Power witness Mr. Robinson stated that Georgia Power has
8 studied transmission needs for solar scenarios of 6 GW, 8 GW, and 10 GW of solar
9 resources.⁹ Those scenarios and analyses are not described in the ITS transmission plan.
10 Georgia Power should provide more information about its scenario analysis for solar and
11 other renewables in its transmission plan as part of the IRP.

12 **VII. Interregional Transmission Planning**

13 **Q: What is interregional transmission planning?**

14 A: Interregional planning is the planning of transmission across the borders of balancing
15 authorities to seek the same kind of benefits that can be achieved through better
16 transmission planning within the balancing authority. One important difference is that
17 because economic dispatch occurs entirely within each balancing authority, "sales" do not
18 happen in that context. In the Southeast, sales between balancing authorities are usually
19 bilateral market transactions that are negotiated between utilities.

⁹ Hearing Transcript, Vol. 1 at 0452:12-17.

1 **Q: Does interregional planning provide reliability and resilience benefits?**

2 A: Yes. The ability to import large quantities of electricity from other regions was critical in
3 reducing the impact of severe weather events like Winter Storm Elliott.¹⁰

4 **Q: Did Congress recently direct NERC to study interregional transfer capability?**

5 A: Yes, Congress directed NERC to conduct the Interregional Transfer Capability Study
6 (ITCS) in the Fiscal Responsibility Act of 2023, and NERC completed its study in
7 November 2024.¹¹

8 **Q: What was the purpose of the study?**

9 A: The key purpose of the study was to measure the amount of interregional transfer capability
10 that exists between the various regions. NERC completed its study but also stated that
11 “[T]he actual transfer capability available during real-time operations may be different
12 from the calculated transfer capability, because system conditions during actual operation
13 may be different from the studied conditions.”¹²

14 **Q: Did NERC recommend that utilities study and maintain the transfer capability**
15 **between adjacent regions?**

16 A: Yes,¹³ and it is my recommendation that Georgia Power be directed to study the transfer
17 capability between it and larger adjacent balancing authorities in various weather scenarios
18 and advise the Commission on its views of the NERC study. Additionally, Georgia Power

¹⁰ See Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott, FERC, NERC and Regional Entity Staff Report, October 2023. <https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022>).

¹¹ The full report is available at: https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

¹² *Id.* at 136.

¹³ *Id.*

1 should work with its sister operating companies because transfer capability to the entire
2 balancing authority is the critical question when it comes to reliability and resilience in
3 extreme weather.

4 **Q: What do you recommend with respect to this issue?**

5 A: I recommend that the Commission direct Georgia Power to conduct and submit a study of
6 the potential benefits of increasing the interregional transmission transfer capability
7 between its balancing authority and adjacent regions in various weather scenarios,
8 consistent with NERC's recommendations. The study should evaluate current and potential
9 capacity to import/export power during extreme events, identify constraints and needed
10 upgrades, and include coordination with sister companies and adjacent balancing
11 authorities.

12 **VIII. Conclusion and Recommendations**

13 **Q: Please summarize your recommendations to the Commission.**

14 A: I recommend that the Commission:

- 15 1. Direct Georgia Power to conduct and submit a study on the potential benefits of joint
16 transmission planning with Alabama Power and Mississippi Power that reflects the
17 integrated operations of the Southern Company pool. This planning should:
 - 18 a. Use multiple future scenarios to capture a range of risks;
 - 19 b. Consider multi-value benefit streams (e.g., economic dispatch, reserve margins,
20 reliability); and
 - 21 c. Include a cost allocation framework to ensure costs are roughly commensurate
22 with benefits across jurisdictions.

1 2. Direct Georgia Power to incorporate utility-scale and customer-driven clean generation
2 resource deployment into its transmission planning assumptions, including various
3 levels of deployment. This should include:

- 4 a. Utility-scale solar in the IRP;
5 b. Anticipated deployment under the CARES customer subscription program and
6 the proposed Customer Identified Resource option; and
7 c. Consideration of geographic and grid access factors in siting analysis.

8 3. Direct Georgia Power to conduct and submit a study of the potential benefits of
9 increasing the interregional transmission transfer capability between its balancing
10 authority and adjacent regions, consistent with NERC's recommendations. The study
11 should:

- 12 a. Evaluate current and potential capacity to import/export power during extreme
13 events;
14 b. Identify constraints and needed upgrades; and
15 c. Include coordination with sister companies and adjacent balancing authorities.

16 **Q: Does this conclude your testimony at this time?**

17 **A: Yes.**

Table 1 – Recommendations and Risks Addressed

Recommendation	Risks Addressed by the Recommendation
Conduct and submit a study on the potential benefits of joint transmission planning with Alabama Power and Mississippi Power that reflects the integrated operations of the Southern Company pool.	Missed opportunities for cost savings and cost-effective development of additional transmission capacity
Instruct Georgia Power to incorporate expected utility-scale and customer-driven clean generation resource deployment into its transmission planning assumptions	Interconnection backlogs and project development delays, which lead to more expensive PPAs
Direct Georgia Power to conduct and submit a study of the potential benefits of increasing the interregional transmission transfer capability between its balancing authority and adjacent regions, consistent with NERC's recommendations	Reliability and resilience, extreme weather events