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February 15, 2024

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; Docket No. 55378

Dear Ms. Tanner:

Please find enclosed an electronic version of the following **Direct Testimony of Chelsea Hotaling on behalf of Georgia Interfaith Power & Light** to be filed in Docket No. 55378.

Please also find enclosed an electronic version of the Trade Secret version of the Direct Testimony of Chelsea Hotaling on behalf of GIPL. Additionally, the testimony will be delivered to the Commission in hard copy, including a sealed envelope containing the Trade Secret version of Ms. Hotaling's testimony.

Respectfully submitted,

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BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of	)	
	)	
Georgia Power Company's 2023	)	**Docket No. 55378**
Integrated Resource Plan Update	)	
	)	
	)	

<u>DIRECT TESTIMONY OF CHELSEA HOTALING</u>
<u>ON BEHALF OF GEORGIA INTERFAITH POWER & LIGHT</u>

February 15, 2024

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I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A: My name is Chelsea Hotaling. I am a Consultant at Energy Futures Group, located at 30 Court Street, Canton, New York, 13617.

Q: MS. HOTALING, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A: I have worked for seven years in electric utility regulation and related fields. I have reviewed dozens of integrated resource plans ("IRPs") and related filings by utilities in Arizona, Colorado, Kansas, Kentucky, Indiana, Iowa, Michigan, Minnesota, Missouri, Montana, New Mexico, Nova Scotia, Puerto Rico, and South Carolina. I have performed my own capacity expansion, production cost, and reliability modeling in numerous cases using multiple models including EnCompass, Aurora, PLEXOS, and the Strategic Energy & Risk Valuation Model ("SERVM").

I received a Bachelor's Degree in Accounting and Economics from Elmira College in 2011. I also received a Master of Business Administration Degree in 2012, a Master's Degree in Environmental Policy in 2019, and a Master's Degree in Data Analytics in 2020, from Clarkson University. My resume, included as **Exhibit CH-1,** provides additional detail regarding my professional and educational experience.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A. No, I have not. I have filed testimony before the Public Service Commission of West Virginia, the Public Service Commission of South Carolina, the Kentucky Public Service Commission, the Michigan Public Service Commission, the Iowa Utilities Board, and the Colorado Public Utilities Commission.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A: I am testifying on behalf of Georgia Interfaith Power and Light ("GIPL").

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: I was asked to review the assumptions and recommendations Georgia Power Company ("GPC" or "the Company") made related to its 2023 IRP Update,[1] with a focus on the load forecast, new resource assumptions, and Georgia Power's proposed pathway for meeting projected load growth.

Though I reviewed the entire filing, I focused on the resources needed to meet the projected load growth between now and the winter of 2028/2029.

Q: WHY DID YOU FOCUS ON MEETING ENERGY NEEDS BETWEEN NOW AND THE WINTER OF 2028/2029?

A: Georgia Power has indicated that the period of load that it is addressing in this IRP Update is narrow: today through the December 2028.[2] Georgia Power has repeatedly indicated that the All-Source and Battery Energy Storage System RFPs that were approved in the 2022 IRP would address capacity needs beginning in the winter of 2028/2029.

[1] On December 4, 2023, Georgia Power Company submitted and requested approval to procure several resources including: two Power Purchase Agreements ("PPAs"), up to 1,000 MW of battery energy storage systems ("BESS"), up to 1,400 MW from combustion turbine ("CT") resources, two new customer-sited distributed energy resource ("DER") programs, one new demand response program, an amendment to one existing demand response program. Georgia Power also asked for approval of the proposed Flex Capacity framework and transmission system improvements related to the resources requested in the Company's filing. Georgia Power 2023 Integrated Resource Plan Update ("IRP Update Main Document").
[2] Georgia Power 2023 IRP January 16, 2024 Hearing Transcript "Hearing Transcript" at 479:2-4.

II. SUMMARY OF RECOMMENDATIONS

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A: My recommendations are as follows:

1. Load Forecast

a. The Commission should only approve resources sufficient to meet the most likely load growth to occur, which has been identified by Georgia Power's modeling at the 50th percentile (or P50).

b. The Commission should direct Georgia Power to track specific data that will improve the accuracy of future forecasting for large-load customer growth.

2. Proposed Resources

a. The Yates CTs are not necessary to support Georgia Power's projected capacity needs between now and 2028, even if the Commission uses Georgia Power's extreme growth estimates (P95).

i. I recommend that the Commission defer consideration of the Yates CTs until the 2025 IRP, when it will have the benefit of a fulsome long-term planning process. In the alternative, the Commission should direct Georgia Power to expedite the upcoming all-source RFP to determine the economically optimal portfolio of resources to meet projected capacity needs.

ii. The Commission should not charge billpayers for the approximately $250 million in expenses that Georgia Power has identified as its development and cancellation costs if the Yates CTs are not approved.

b. Battery Energy Storage Solutions are sufficient to meet Georgia Power's capacity needs between now and 2028, and they can be competitively procured.

i. I recommend that the Commission direct Georgia Power to issue an expedited BESS RFP for at least 1,410 MW as soon as possible.

3. Flex Capacity

a. A flex capacity framework is unnecessary; it unnecessarily shifts the Company's risk-taking from its shareholders to its customers. The Commission should deny this request.

III. GEORGIA POWER'S LOAD FORECAST

Q: PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS ABOUT GEORGIA POWER'S LOAD GROWTH.

A: Georgia Power has relied on a generally accepted statistical method to forecast new load growth coming to Georgia, but Georgia Power's interpretation of its own forecast unreasonably overestimates the pace of growth. Georgia Power relies on a load projection that its own statistical analysis suggests will be higher than actual demand 95% of the time. However, Georgia Power's statistical method also identified the capacity-needs that are **most likely** on an annual basis, and I recommend that the Commission plan to acquire resources to meet that probable need (identified as P50 or the 50th percentile).

Q: PLEASE BREAK THAT DOWN FOR ME. TO START, WHAT HAS CHANGED SINCE THE 2022 IRP THAT HAS RESULTED IN THIS NEW LOAD FORECAST DISCUSSION?

A: Georgia Power has reported a change to the load forecast that was modeled for the 2022 IRP as a result of large-load customers (that Georgia Power calls "economic development projects") responding to the economic growth and business opportunities in the state. This has resulted in a significant difference between the load growth projected in the 2022 IRP and Georgia Power's chosen load growth projections for this 2023 IRP Update. By December 2028, Georgia Power is now planning for 4,094 MW more than it projected during the 2022 IRP. Its own projections, however, suggest that 3,141 MW of growth through 2028 is most likely.

Winter Peak	GPC 2022 IRP Budget	GPC Most Likely Load Growth (P50)	GPC 2023 IRP Planning (P95)	Difference between 2022 IRP and 2023 Update (P50)	Difference between 2022 IRP and 2023 Update (P95)
2024	15,581	15,268	15,283	(313)	(298)
2025	15,636	15,796	15,947	160	312
2026	15,657	16,790	17,256	1,133	1,599
2027	15,673	18,163	18,928	2,490	3,255
2028	15,657	18,798	19,751	3,141	4,094
2029	15,757	19,390	20,551	3,633	4,793
2030	15,796	19,966	21,326	4,170	5,530
2031	15,957	20,408	21,880	4,451	5,923

Table 1. 2022 IRP Winter Peak Load Forecast Compared to 2023 IRP Update Forecast[3]

Q: GEORGIA POWER'S NEW LOAD FORECAST RELIES ON A NEW APPROACH TO FORECASTING. DO YOU AGREE THAT A NEW FORECASTING APPROACH IS NEEDED TO CAPTURE GEORGIA'S LARGE LOAD GROWTH?

A: Yes. Traditionally, Georgia Power uses linear regression to develop the baseline load forecast used in the IRP planning process. This methodology relies on traditional economic and demographic variables as drivers of energy use. Since these models are based on the historical trends for the different variables included in the model, it is challenging for the traditional forecast to be able to account for the large-load projects arising from the economic growth Georgia is experiencing. As a result, it is reasonable for Georgia Power to supplement its baseline forecasting approach with another methodology to try to forecast this distinctive rapid, large load growth.

Q: HOW DID GEORGIA POWER DEVELOP THE LOAD FORECAST MODEL THAT WAS USED IN THIS 2023 IRP UPDATE?

A: Since the load growth experienced by Georgia Power in the last two years is not captured in traditional load forecast models, Georgia Power's load forecast model[4] attempted to capture the uncertainty around several variables, including the probability of the "economic development projects" successfully coming online, the timing of the load coming online or experiencing delays, and the level at which load will materialize relative to what the customer initially indicated it would demand. Specifically, Georgia Power decided to

[3] Extrapolated from data provided in Georgia Power's response to STF-PIA-4-13 Attachment and DEA-1-5 Att. B.
[4] The load forecast model is referred to as the "Load Realization Model" in the workpapers provided by Georgia Power with this filing.

utilize the @RISK software which performs Monte Carlo simulations on variables specified by Georgia Power to try to capture the uncertainty related to the load growth.

Q: WHAT IS A MONTE CARLO SIMULATION AND WHY IS IT USED HERE?

A: A Monte Carlo simulation is a widely accepted statistical process that helps estimate the probability of uncertain events. In this case, the Monte Carlo simulation was designed by Georgia Power to estimate the probability (likelihood) that certain amounts of load will actually be demanded by large customers on its system.

Q: PLEASE DESCRIBE THE VARIABLES GEORGIA POWER USED IN ITS MONTE CARLO SIMULATION TO ESTIMATE THE UNCERTAINTY OF ITS FUTURE LARGE LOAD DEMAND.

A: The first variable in the model is what Georgia Power calls the probability of "Project Success," which represents a compilation of three separate inputs:

(1) Whether the project will be located in the state of Georgia (P1)

(2) Whether Georgia Power will be selected as the electric service provider for the project (P2)

(3) The success rate of the project after the contract is signed (P3)

Table 2 below shows an example of how these three inputs were set up in what Georgia Power calls the "Load Realization Model" to represent the different combinations that arise from the assumptions Georgia Power made for each of these three inputs. For P1, each project was assigned either a [redacted] or [redacted] value. For P2, each project was assigned a value of [redacted], [redacted], [redacted], or [redacted]. P3 is the success rate that Georgia Power has reported for its historical projects. Georgia Power has stated that it has a recent success rate of about [redacted] for projects coming online after a service contract is signed.[5] Overall Project Success is based on the product of P1 x P2 x P3. The product of these three factors is ultimately the input that is factored into the Monte Carlo simulations for the model.

[5] Georgia Power response to STF-DEA-1-13.

GA as State Selection (P1)	GPC as Provider (P2)	Project Reaching COD (P3)	Project Success (P1xP2xP3)
[redacted]			

Table 2. Project Success: Input Variables in the Load Realization Model

The value reported for the Project Success represents the percentage of times that the load will materialize in each simulation. For example, if a project has a success value reported at [redacted], that means that out of the 100,000 combinations that are drawn in the Monte Carlo simulation, the number of iterations in the model simulation where the announced load is included is based on the project success value, or [redacted].[6]

The other two variables included to capture uncertainty in the load forecast model include the probability that the announced load for the project will be different from the load that materializes (Metered vs. Announced Load) and the probability that the Commercial Operation Date ("COD") of the project will be delayed. Georgia Power assigned both of these variables a triangular distribution with a low, mid, and high value. Georgia Power has acknowledged that without historical data, the triangular distributions have been assigned to reflect what it considers the minimum, maximum, and most likely outcomes.[7] The value for each of the six potential customer segments is shown in **Table 3**.

[6] Georgia Power response to STF-DEA-1-16 subpart b.
[7] 2023 IRP Update Technical Appendix ("Technical Appendix") 7, TS-Load and Energy Forecast at 18.

	Minimum	Most Likely	Maximum
Cryptocurrency	[redacted]		
Datacenter			
Miscellaneous			
Warehouse			
Distribution			
Industrial (All Segments)			

Table 3. Metered vs. Announced Load: Triangular Distribution Values

Within the model, the metered vs. announced load variable is used to scale the announced load of the project according to the ramp-up schedule[8] that is also specified in the model. For example, the announced load for a project might be 300 MW, but there is some uncertainty around whether this full level of load will materialize, as it could be less than 300 MW. With regard to this uncertainty, Georgia Power stated, "… based on Georgia Power's experience, the load announced by a customer is only an estimate of its metered load, which can materialize at a lower level than that at the time of the customer's initial announcement."[9] The model will interpret this uncertainty by pulling from the low, mid, and high values that Georgia Power has specified for the customer segments. In the example I referenced above, if the project is at 300 MW of announced load, then that project will materialize as a percentage of that announced load in the Load Realization Model (i.e., if the simulation run picks a maximum value of 75%, the 300 MW load will appear as 225 MW in the outputs).

Table 4 below shows the triangular distribution values for Commercial Operation Date ("COD") delay. Based on the values specified by Georgia Power, this means that the maximum delay for any project in the model is [redacted] months and the most likely value is [redacted] months.

[8] The ramp-up schedule reflects that the entire load is typically not required on Day-1 of a project. For example, if a project has an announced load of 300 MW, it might expect to need 100 MW on Day-1 and then ramp up by 50 MW each year to reach the 300 MW announced load by 2027.
[9] Technical Appendix 7, TS Load and Energy Forecast at 16.

	Minimum	**Most Likely**	**Maximum**
Commercial Operation Date (“COD”) Delay	[redacted]		

Table 4. COD Delay (Months): Triangular Distribution Values

Once the @RISK model performs 100,000 draws on these uncertain variables, the load for each potential project is added together to arrive at the portfolio level load projection each year that Georgia Power then includes as an adjustment to the baseline load forecast.

Q: DID GEORGIA POWER’S LOAD REALIZATION MODEL PROVIDE A SINGLE ESTIMATE FOR PROJECTED LOAD?

A: No. Georgia Power’s Load Realization Model is based on 100,000 simulations, with each individual simulation representing a different estimate of potential load growth based on the assumptions that Georgia Power assigned to the uncertain variables. The 100,000 simulations are then combined to give a range of possible load growth and to show how likely it is for each load projected to actually occur.

As a matter of statistics, the most likely load growth scenario is the data point in the middle, where 50% of the scenarios project more growth and 50% of the scenarios project less growth. This data point is referred to as P50, or the 50th percentile. Similarly, probabilities can be assigned to all the other data points as well. P05 (the 5th percentile) and P95 (the 95th percentile) describe load forecasts where just 5% of the scenarios run are lower or higher than that amount of load. In other words, scenarios smaller than P05 or larger than P95 are very unlikely to occur.

Q: DID GEORGIA POWER ALSO PROVIDE THE RESULTS OF THE 50TH PERCENTILE?

A: Yes. In addition to the total winter load forecasts shown in Table 1, Georgia Power provided the new large-load-only P50 forecast in response to a discovery request from Public Interest Advocacy (“PIA”) Staff.[10] **Table 5** below shows a comparison between the 95th and 50th percentiles resulting from Georgia Power’s Load Realization Model for new large-load projects. In year 2026, the 95th percentile load level indicates that 95% of

[10] Georgia Power response to TS-STF-DEA-1-5 Attachment A.

potential load outcomes are less than [redacted] MW and only 5% of the possible load outcomes are higher than [redacted] MW.

Year	P95	P50
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]

Table 5. Comparison of the P95 and P50 Load Forecasts[11]

Q. HOW DID GEORGIA POWER DECIDE WHICH PART OF THE LOAD REALIZATION MODEL'S LOAD GROWTH RANGE TO USE?

A: Georgia Power chose to plan for P95: That means that Georgia Power is planning for bigger load growth than its own simulation says it needs 95% of the time.[12] Said another way, Georgia Power is planning for more load growth than its model says will be needed in 95,000 out of the 100,000 simulations run.[13]

Georgia Power provided many explanations for choosing the high-end of possible load (P95) in its testimony:

- "[P95] was chosen because it supports the ask that we have in front of this Commission."[14]

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[11] Technical Appendix 7, TS Load and Energy Forecast Table 1.5.2.3-1 at 20 and Georgia Power response to TS-STF-DEA-1-5 Attachment A.
[12] Technical Appendix 7, Load and Energy Forecast at 3. As Georgia Power stated, "[…] P95 indicates a load level where 95% of all potential combinations fall at or below this level, and 5% of the load combinations fall above it."
[13] Hearing Transcript at 378:4-8.
[14] Hearing Transcript at 378:21-23.

- "[P95] accommodates for the rapid growth that we have seen throughout 2023 where different sensitivities that we did were doubled a couple of times throughout the year."[15]
- "[P95] accommodates for the current capacity market conditions."[16]
- "[T]hat higher load level was chosen because that's what we expect the State's load growth to be. . . . [W]e continue to see load growth outrunning the forecast."[17]
- "From a statistical perspective, yes, I agree that the P50 level represents the median of the range of all potential outcomes. But for the purposes of this IRP, we're picking a higher-level degree to represent the increases in the load that we have seen throughout 2023 and because it's a better level to plan . . . for our resources."[18]
- "[T]here's a lot more risk on the upper side than the lower side."[19]

Q: IS IT REASONABLE TO USE THE P95 FORECAST FOR THIS IRP UPDATE?

A: No. It is not reasonable to plan for a load scenario that is at or higher than 95% of modeling scenarios for this IRP Update.

Q: WHY IS IT UNREASONABLE TO USE THE P95 FORECAST FOR THIS IRP UPDATE?

A: Georgia Power should base planning on the 50th percentile (P50) for a few reasons:

First, load forecasts that utilities use as inputs for capacity expansion models are typically 50/50 forecasts, which means there is a 50% chance of an over-forecast (meaning the forecast is higher than actual needs) and a 50% chance of an under-forecast (meaning the forecast is lower than actual needs), as reflected in the below image.[20] (Notably, for the

[15] Hearing Transcript at 378:23-379:1.
[16] Hearing Transcript at 379:1-2.
[17] Hearing Transcript at 379:3-8.
[18] Hearing Transcript at 382:20-383:1.
[19] Hearing Transcript at 379:8-9.
[20] NARUC, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms, November 2023, at 18. Retrieved at: 0CC6285D-A813-1819-5337-BC750CD704E3 (naruc.org)

Southern Company System, load forecasting erred on the side of over-forecasting every year between 2000-2017.[21])

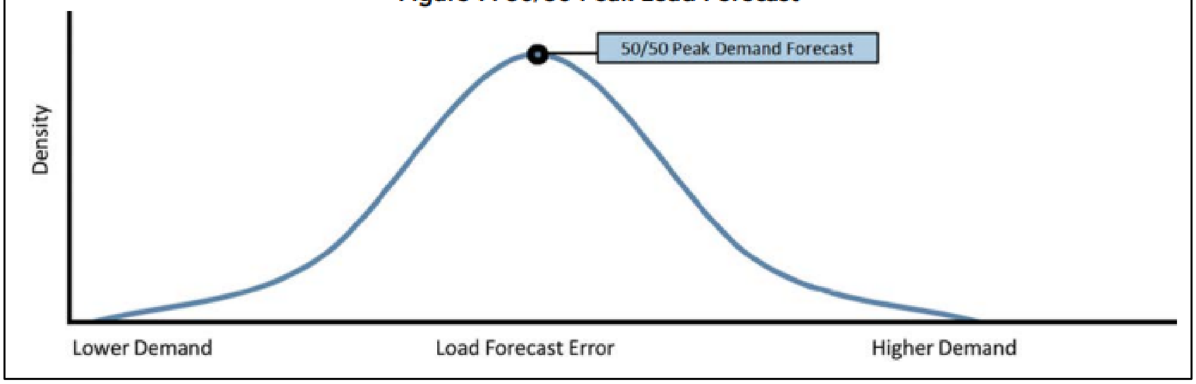

Figure 7: 50/50 Peak Load Forecast

The same idea applies here: The 50th percentile is the median of the load level in the model. Intuitively, using P50 is logical, because it uses the modeling for the very purpose for which the model was developed: To estimate the most likely outcome. Here, Georgia Power used a Monte Carlo simulation to make an informed projection about how demand will grow in Georgia. The 50th percentile reflects a balance between demand that may or may not materialize.

Second, I agree with Georgia Power's written testimony that it is reasonable to "plan for a probable amount of customer choice load and avoid overestimating load additions that could add unnecessary capacity to the electric system."[22] **The 95th percentile, used by Georgia Power, will be an overestimation 95% of the time.** As a matter of basic statistics, **the 50th percentile is the amount of load that is more likely to occur than not—or, is probable.**

Third, Georgia Power's Target Reserve Margin ("TRM") already accounts for the risks inherent in load forecasting. Georgia Power has one of the largest winter reserve margins among its Southern peers.[23] And Georgia Power's TRM explicitly accounts for load

[21] IRP Update Technical Appendix Volume 1, Southern Company, *An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System*, January 2022 (Public version) Table 1-3.
[22] Georgia Power Direct Testimony at 19:20-22.
[23] Hearing Transcript at 501:11-16; *see also, e.g.*, Hearing Transcript at 502:1-3; 2023 Long-Term Reliability Assessment December 2023, North American Electric Reliability Corporation, at 83&91; 2023 Resource Adequacy

forecasting error.[24] In addition, as I will discuss in more detail in the next section, Georgia Power plans for a higher reserve margin than utilities typically plan for, which is a loss of load expectation ("LOLE") of one day in ten years or 0.1 days per year. In the 2022 IRP TRM Study, the minimum reserve margin for Georgia Power was found to be 20%, but Georgia Power took additional steps to evaluate the economics and risk components for a reserve margin higher than 20%.

Fourth, I disagree with Georgia Power's oral testimony which suggested that using the 95th percentile of growth is justified by either "rapid load growth" or by the observations that load growth is "outrunning the forecast." **To the contrary, rapid load growth is exactly what this model is designed to capture, using probabilities assigned by Georgia Power**.

The model incorporates estimates of the likelihood of each project's overall success. As I discussed earlier in my testimony, the project success variable is based on the probabilities chosen by Georgia Power for (1) the project selecting Georgia as the state to locate in, (2) the project selecting Georgia Power as the electric service provider, and (3) the likelihood of projects materializing after a contract has been signed. Table 1 provided the unique project success values contained in Georgia Power's Load Realization Model based on the input assumptions for each project. **Table 6** below shows the total announced load contained within the Load Realization Model based on the probability of Project Success. The model interprets the Project Success value as the percentage of iterations where the project will be considered a success, and the announced load will be included in the model and reflected in the resulting total level of load for Georgia Power. This shows that the announced loads with lower levels of project success are being considered in the Load Realization Model and the announced load of these lower probability of success projects are being factored into the load model.

Study for Duke Energy Carolinas & Duke Energy Progress (Reserve margins below 21%), Astrape Consulting, at 3; 2023 Virginia Electric and Power Company, Integrated Resource Plan 2023 at 59 (Reserve margins below 15%).

[24] IRP Update Technical Appendix Volume 1, Southern Company, *An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System*, January 2022 (Public version) Figure III.1 at 13.

Project Success	Announced Load
[redacted]	

Table 6. Announced Load Based on Project Success

Fifth, I have seen no support for Georgia Power's oral testimony that there is "a lot more risk from the upper side than the lower side."[25] Risk is frequently considered as part of system planning, but in this case, the risk of overbuilding the system versus the risk of underbuilding has a very different dynamic than typical risk-benefit assessments of load growth. In large part, that is because **Georgia Power's projected load is largely from customers that it is not obligated to serve.**

If Georgia Power adds capacity to meet the projections of P50, there is an equal chance that Georgia Power will overbuild as underbuild. If Georgia Power overbuilds (meaning load demand ends up being lower than P50), existing customers will incur unnecessary costs for that additional capacity. As summarized succinctly by Georgia Power, "If we're wrong [about load growth], that would not be beneficial for customers."[26] If Georgia Power underbuilds (meaning load demand ends up being significantly higher than P50), then Georgia Power may need to forego or delay entering into customer choice contracts, which could lead large-load customers to choose a different Georgia electricity provider or choose not to locate in Georgia at all.

Table 7 below shows the announced load across different industry segments and whether that load would be located within Georgia Power's service territory or outside of the service territory. Out of all the announced load included in the Load Realization Model, over half (about [redacted]) is outside of the service territory and would fall under customer choice.

[25] Hearing Transcript at 379: 8-9.
[26] Hearing Transcript at 485:21-22.

	Announced Load (MW)		
Segment	Inside Service Territory	Outside Service Territory	Total
[redacted]			

Table 7. Announced Load (MW) Contained in the Load Realization Model[27]

Q: WHAT RECOMMENDATIONS DO YOU HAVE RELATED TO GEORGIA POWER'S LOAD FORECAST MODEL?

A: First, I recommend that Georgia Power plan for the load growth that its analysis estimates is most likely to occur: the 50th percentile of the load level forecasted for new customers by its Monte Carlo simulation (P50).

Second, I recommend that Georgia Power track specific datapoints relied upon in this new large-load forecasting process to inform future forecasting for large-load customers. To the extent that Georgia Power is not already doing so, I recommend that Georgia Power track (and report) data including:

a) the date first contacted by the customer,

b) the date when selections are made (the selection of Georgia as the state to locate in and the selection of Georgia Power as the electric service provider),

c) the announced load from the customer,

d) dates when any changes were made to the customer's announced load and whether that has an impact on the anticipated ramp-up schedule,

e) date the customer was connected and the first month of service,

[27] Georgia Power response to STF-DEA-6-3.

f) the actual connected load, and

g) the actual load ramp-up over time.

Based on some of the responses Georgia Power provided in discovery,[28] it appears that the Company may be tracking this information now, but if the Company is not, all of these data points are critical to help inform the decisions about what values to include for the uncertain variables in the Load Realization Model.

IV. GEORGIA POWER'S NEED FOR NEW RESOURCES

A. Georgia Power's Winter Capacity Position

Q: PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS ABOUT ALTERNATIVE OPTIONS TO FULFILL GEORGIA POWER'S CAPACITY NEEDS.

A: Georgia Power does not need the proposed Yates CTs to fulfill its capacity needs in advance of the BESS and all-source RFPs designed to serve winter 2028 and beyond. Instead, approximately 1,410 MW of BESS resources, which have been identified by Aurora as the economically optimal investments, are sufficient to meet Georgia Power's near-term capacity needs under the P50 scenario. **Even if the Commission plans to meet Georgia Power's high-end 95th percentile load estimate, Plant Yates is still not necessary to meet Georgia Power's capacity needs.** Instead, a combination of BESS resources and PPAs in 2027 and 2028 could meet these needs.

Q: HOW DID YOU EVALUATE ALTERNATIVES TO GEORGIA POWER'S PROPOSED RESOURCE MIX?

A: I reviewed Georgia Power's resource mix study and the results of Georgia Power's Request for Information for capacity to the market. I also evaluated Georgia Power's winter capacity position under both the P50 and P95 load forecasts developed by Georgia Power. Then I determined which resources identified as "economically optimal" by Aurora could fulfill Georgia Power's capacity needs. I prioritized non-thermal resources, which is also consistent with the resource selection by Aurora in the time frame at issue in this IRP Update.

[28] Georgia Power response to STF-PIA-7-10.

Q: PLEASE DESCRIBE THE RESOURCE MIX STUDY RESULTS THAT YOU REVIEWED.

A: I reviewed Georgia Power's use of the Aurora model as part of its resource mix study. The Aurora modeling process identifies the economically optimal resources to meet the load growth identified by Georgia Power (P95) in order to minimize total system costs. Candidate resources are offered for selection in the model, and Aurora will select the optimal build of new resources. Georgia Power made updates to the cost assumptions for the new generic resources that were modeled for the 2022 IRP.

Q: WHICH RESOURCES DID THE AURORA MODELING IDENTIFY AS ECONOMICALLY OPTIMAL TO MEET GEORGIA POWER'S P95 LOAD BETWEEN 2024 and 2028?

A: Aurora identified the Mississippi Power PPA (for 2027 and 2028 only), solar, batteries, and 300 MW of CTs as economically optimal to meet the P95 needs identified by Georgia Power between now and 2028. **Table 8** below shows the annual incremental new resources selected in the Aurora capacity expansion modeling for the "MG0-Base GPC" run. The four-hour BESS additions between 2027 and 2028 total 1,580 MW. These resources would be incremental to the 500 MW BESS (and all-source RFP) that was ordered from the 2022 IRP, which Georgia Power assumes will be powering the grid by the end of 2028.[29]

Year	CT with SCR	MPC PPA	Solar	Battery 4-Hour
2024				
2025				
2026				
2027		750		900
2028	300		750	780

Table 8. Aurora Modeling Annual New Resource Additions (MW)[30]

Q: HOW DOES THE AURORA MODELING ALIGN WITH THE PROJECTS THAT RESPONDED TO THE REQUEST FOR INFORMATION ("RFI") ISSUED BY GEORGIA POWER?

[29] Georgia Power response to STF-JKA-3-16 indicates that the 500 MW ESS from the 2022 IRP was modeled in Aurora as the resource "O3_2022_IRP_ESS". *See also*, IRP Update Main Document at 15.
[30] Georgia Power workpaper named "PD Capacity Expansion Plans Supplemental – Errata", worksheet named "MG0 (GPC Only)".

A: Georgia Power received RFI bids for about 3,000 MW of capacity from BESS resources for 2026, 2027, and 2028.[31] About half of those resources (approximately 1,400 MW) are already planned to be available before the end of 2028.[32] Georgia Power's graphics and **Table 9** below summarize the bids received by Georgia Power. Table 9 shows the total annual nameplate capacity from the BESS and renewable plus BESS bids that Georgia Power received in response to the RFI. [33]

Resource Types	Exisiting Project	New Project	Planned Project	Not Provided	Grand Total
ESS Other (Flywheel, CO2, etc.)		4		1	**5**
ESS Standalone		6	7	1	**14**
Nuclear Energy		1			**1**
Solar + Storage		4	9		**13**
Solar Only	4				**4**
Thermal	4				**4**
Grand Total	**8**	**15**	**16**	**2**	**41**

[34]

Breakdown of Resource Types		
Capacity Resource Type	**# of Responses**	**Sum of Capacity (MW)**
ESS Other	4	769
BESS Standalone	13	2,695
BESS + solar	12	1,680
Solar Only (not applicable)[3]	5	*1,228*
Thermal (CC / CT)	2	1,243
Nuclear Energy	1	280
Total	**37**	**6,667**

[35]

	2026	**2027**	**2028**	**2029**	**2030**
BESS	[redacted]				
Renew+BESS					
Total					

Table 9. Summary of Standalone BESS and Renewable+BESS Projects (Nameplate MW)[36]

[31] Hearing Transcript at 354:10-16.
[32] Georgia Power response to TS STF-PIA-9-13, Attachment A at 1 (determined not to be Trade Secret by email exchange with Georgia Power counsel).
[33] [redacted] of standalone and renewable plus BESS resources were bid in without a specified online date.
[34] Georgia Power response to TS STF-PIA-9-13 Attachment B.
[35] Georgia Power response to TS STF-PIA-0-13 Attachment A.
[36] Based on information provided in the workpaper named "TS_ResponseDataScrubbed_ForRFISummary".

Q: PLEASE DESCRIBE GEORGIA POWER'S CAPACITY NEEDS BEFORE THE END OF 2028.

A: **Table 10** below shows Georgia Power's capacity position relative to a winter TRM of 24.43% for 2024-2026 and 25% starting in 2027 under the P50 load forecast. This capacity position look also evaluates the system with and without consideration of the additional capacity from the Mississippi Power and Santa Rosa PPAs. Table 10 shows the level of capacity that would be needed to meet the winter TRM without consideration for the Mississippi Power or Santa Rosa PPAs.

(P50 – No PPAs)	**2024**	**2025**	**2026**	**2027**	**2028**
Peak Demand	15,268	15,796	16,790	18,163	18,798
Total Existing Capacity	19,980	21,196	21,296	21,785	22,088
Reserve Margin	**30.9%**	**34.2%**	**26.8%**	**19.9%**	**17.5%**
Capacity Needed				918	1,410
Reserve Margin	**30.9%**	**34.2%**	**26.8%**	**25.0%**	**25.0%**

Table 10. Georgia Power Winter Capacity Position Under P50 and No PPAs

(P50 – PPAs Included)	**2024**	**2025**	**2026**	**2027**	**2028**
Peak Demand	15,268	15,796	16,790	18,163	18,798
Total Existing Capacity	19,980	21,196	21,296	21,785	22,088
Reserve Margin	30.9%	34.2%	26.8%	19.9%	17.5%
Add Proposed PPAs:					
MPC PPA	750	750	750	750	750
MPC PPA Sale	-500	-500			
Santa Rosa PPA		230	230	230	230
Total Existing & PPA Capacity	**20,230**	**21,676**	**22,276**	**22,765**	**23,068**
Reserve Margin	**32.50%**	**37.22%**	**32.67%**	**25.34%**	**22.71%**
Capacity Needed					430
Reserve Margin	**32.50%**	**37.22%**	**32.67%**	**25.34%**	**25.00%**

Table 11. Georgia Power Winter Capacity Position Under P50 and the PPAs

Table 11 shows that when the PPAs are included under the P50 load forecast, the capacity need for Georgia Power starts in 2028 at 430 MW. This is in comparison to the 2,400 MW worth of supply side capacity that Georgia Power is requesting.

I also evaluated the winter capacity position for Georgia Power under the P95 load forecast as shown in **Table 12** below. I calculated the level of capacity that Georgia Power would need to arrive at the winter TRM: Under the P95 forecast, after accounting for the PPAs, Georgia Power needs 895 MW in 2027 and 1,621 MW in 2028.

(P95 – PPAs Included)	**2024**	**2025**	**2026**	**2027**	**2028**
Peak Demand	15,283	15,947	17,256	18,928	19,751
Total Existing Capacity	19,980	21,196	21,296	21,785	22,088
Reserve Margin	30.7%	32.9%	23.4%	15.1%	11.8%
Add Proposed PPAs:					
MPC PPA	750	750	750	750	750
MPC PPA Sale	-500	-500			
Santa Rosa PPA		230	230	230	230
Total Existing & PPA Capacity	**20,230**	**21,676**	**22,276**	**22,765**	**23,068**
Reserve Margin	**32.37%**	**35.92%**	**29.09%**	**20.27%**	**16.79%**
Capacity Needed				895	1,621
Reserve Margin	**32.37%**	**35.92%**	**29.09%**	**25.00%**	**25.00%**

Table 12. Georgia Power Winter Capacity Position Under P95 Load

B. Georgia Power's Winter Target Reserve Margin

Q: PLEASE SUMMARIZE WHAT CONCLUSIONS YOU DREW ABOUT GEORGIA POWER'S RESERVE MARGIN AND HOW IT MAY IMPACT GEORGIA POWER'S CAPACITY NEEDS?

A: Georgia Power has a higher-than-typical reserve margin, because it plans for reliability (as is typical) and then adds additional reserve margin based on economic analysis. However, in the time since the reserve margin study was completed, the primary input for the economic analysis (the cost of CTs) has changed significantly. As a result, it is likely that Georgia Power is relying on a higher planning reserve margin than could be justified if it reevaluated its economic analysis today. These outdated assumptions could lead to Georgia Power overbuilding by approximately 1,185 MW of winter capacity in 2028. Considered another way, updates to Georgia Power's reserve margin study could result in Georgia Power not needing any new capacity beyond what is provided by the PPAs before 2028, even under the P95 growth assumptions.

Q: WHAT TARGET RESERVE MARGIN ("TRM") HAS GEORGIA POWER USED IN ITS CALCULATION OF THE COMPANY'S CAPACITY POSITION?

A: Georgia Power used the winter TRMs that were determined from the SERVM modeling performed for the 2022 IRP, which were 25.50% for 2024-2026 and a 26% starting in 2027 for the Southern Company System.[37] Georgia Power did not rerun its TRM study, but it did update the TRM for the 2023 IRP Update to account for updated diversity factors that are applied to the Southern Company System TRM. This means that the TRM for Georgia Power for this 2023 IRP Update is 24.43% for the short-term (2024-2026) and 25% for the long-term (starting in 2027) after accounting for this diversity factor.[38]

Q: HOW DID GEORGIA POWER DEVELOP ITS TRM FOR THE 2022 IRP?

A: Georgia Power used the SERVM model, which evaluates the ability of a system's resources to meet load across thousands of iterations that include varying assumptions around weather, the load forecast error, and generator forced outages. In many cases, utilities will develop a reserve margin based on meeting the industry standard metric of one loss of load expectation ("LOLE") in ten years or 0.1 events per year. To develop Georgia Power's TRM, Georgia Power takes any additional step to evaluate the expected costs of maintaining reserve capacity, production costs, and reliability costs to determine the economic optimum reserve margin ("EORM"). This evaluation considers the tradeoff between the costs of additional generating capacity on the system versus the improvement in resource adequacy from having those additional generating resources. Georgia Power evaluated the EORM by comparing the production[39] and reliability[40] costs, as determined by the SERVM model, to the incremental capacity cost of new generation over several different winter planning reserve margin levels (ranging from 20% to 32%) to find the point where the sum of the production costs, reliability costs, and incremental capacity costs is minimized. The image below shows the winter EORM from the TRM Study.

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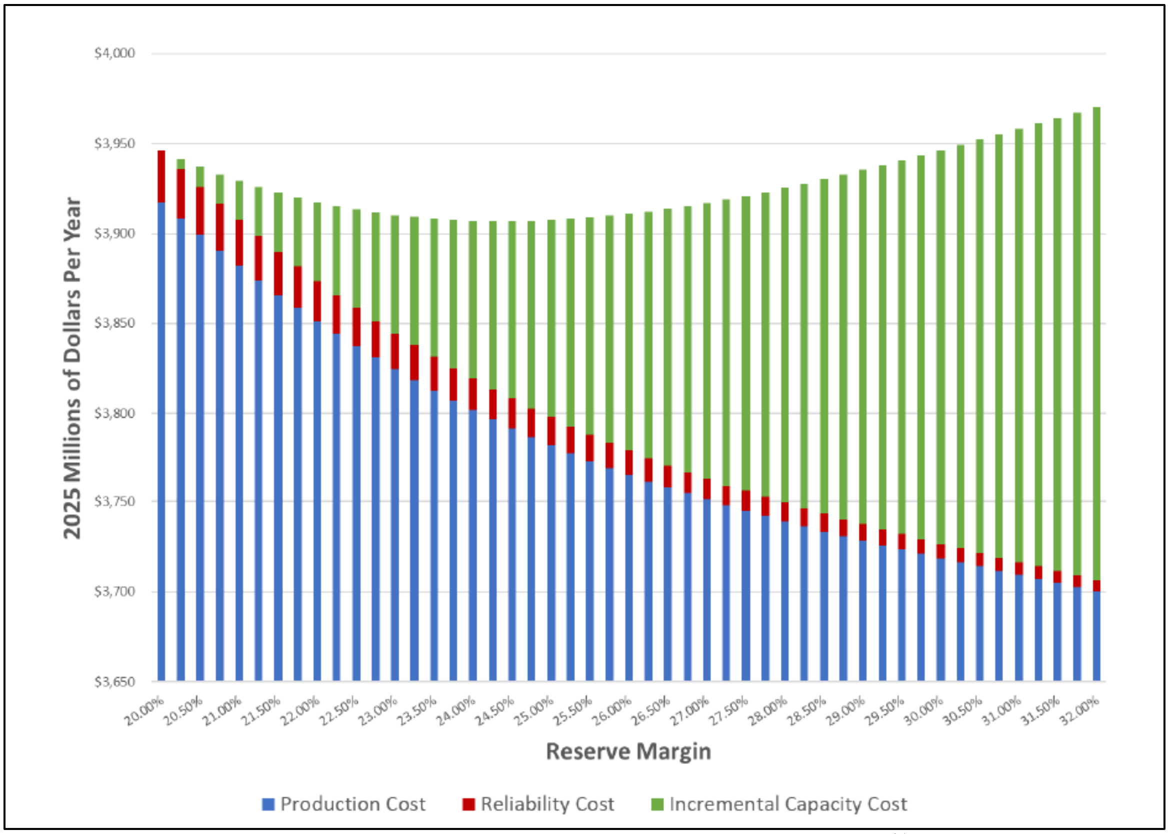
[37] Georgia Power response to Staff JKA-6-1 subpart d.

[38] Georgia Power response to Staff JKA-6-1 subpart d. These diversity factors are reflected in calculation E contained in the capacity position calculations provided in Georgia Power's response to STF-JKA-2-2 Attachment B.

[39] Production costs include the cost of generation (such as fuel and variable O&M) and costs of market purchases.

[40] Reliability costs include the cost of expected unserved energy, emergency market purchases, and the cost to call demand response resources.



Winter EORM U-Curve from the TRM Study[41]

In its 2022 IRP analysis, Georgia Power found this point to be 24.25%,[42] but included an additional step to calculate the potential to mitigate high-cost outcomes using the Value at Risk ("VaR") metric. After also evaluating the VaR metric, Georgia Power increased the EORM from 24.25% to a 26% risk-adjusted EORM.

Q: IN THE TRM STUDY DEVELOPED FOR THE 2022 IRP, WHAT RESOURCE DID GEORGIA POWER USE AS ITS REFERENCE FOR THE INCREMENTAL CAPACITY COST OF NEW GENERATION?

A: Georgia Power used the cost of a combustion turbine ("CT") for the incremental capacity cost of new generation in the determination of the EORM. As Georgia Power stated in the TRM Study:

[41] Technical Appendix Volume 1, Southern Company, *An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System*, January 2022 (Public version) Figure III.1 at 38.
[42] *Id.*

> *For the type of analysis performed in this study, where the objective is to balance the cost of the incremental capacity with the reliability benefits achieved by that capacity addition, it is necessary that the capacity considered represents a true reliability addition, as opposed to an addition for both reliability and energy economics. As such, simple-cycle CT technologies are the appropriate resources to be utilized for the evaluation. Therefore, the cost associated with advancing a CT one year is the cost of capacity used in the analysis. This cost is also known as the "economic carrying cost" or one-year deferral cost associated with that resource.*[43]

Q: CAN THE COST OF NEW GENERATION HAVE AN IMPACT ON THE RESULTING EORM?

A: Yes. It is an essential input into that analysis. Therefore, it is possible that changes in the cost assumption for the capacity of the new generation could impact the EORM. If the capacity price of the new generation is lower, then there will be an economic case for a higher EORM. However, if the capacity price of the new generation is higher, this would have the opposite effect and the EORM will be lower.

Q: DO YOU KNOW WHAT COSTS GEORGIA POWER USED FOR NEW GENERATION IN THE 2022 TRM STUDY?

A: I am not sure what capital costs were used to develop the economic carrying costs of the CTs in the TRM Study developed for the 2022 IRP, because I do not have access to the inputs Georgia Power used to calculate the carrying costs. Given the timing of the TRM study and its development as an input into the Aurora modeling performed for the 2022 IRP, it is likely that the cost was similar or the same as what was modeled by Georgia Power in the resource mix study that was a part of the 2022 IRP.

Q: HOW DO THE COSTS COMPARE BETWEEN THE CTS THAT GEORGIA POWER MODELED IN THE 2022 IRP AND THIS 2023 IRP UDPATE?

A: **Table 13** below shows the capital, fixed operations and maintenance ("O&M"), and variable O&M costs that Georgia Power modeled for CTs in the 2022 IRP and the 2023 IRP Update. The capital cost for CTs in the 2023 IRP Update increased [redacted] from the 2022 IRP.

[43] *Id.* at 29 – 30.

	2022 IRP	2023 IRP
Overnight Costs ($/kW)	[redacted]	[redacted]
Fixed O&M ($/kW-yr)	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]
Maintenance Capital ($/kW-yr)	[redacted]	[redacted]

Table 13. 2022 and 2023 IRP Cost Comparison for CT with SCR[44]

Q: IS IT POSSIBLE THAT THE TRM CALCULATED BY GEORGIA POWER WILL BE DIFFERENT WHEN THE TRM STUDY IS UPDATED?

A: Given the magnitude of the increase in the capital costs of the CTs between the 2022 IRP and the 2023 IRP, it is possible that when Georgia Power performs an updated TRM study the EORM may not be the same as what was calculated in the TRM Study, and it could possibly be lower. Georgia Power reported that sensitivities were performed on the capital cost of the incremental capacity generation as part of the 2022 TRM Study, but the table with those results was redacted. As a result, I am unable to compare the capital costs from the 2023 IRP Update to the costs evaluated in the sensitivity analysis in the TRM Study.

Q: WHAT IMPACT COULD THIS HAVE ON GEORGIA POWER'S CAPACITY POSITION?

A: The TRM Study performed for the 2022 IRP showed that at a LOLE of 0.1 days per year, or the minimum threshold to have adequate reliability for the system, the resulting winter TRM is 20%. **If the TRM Study was reevaluated with a higher capital cost for the CTs, it is possible that the EORM would fall down to the 20% minimum needed** to meet the LOLE standard. If there is a decrease to the TRM then Georgia Power would not need as much additional capacity as it claims in the 2023 IRP Update.

Q: DOES A LOWER TRM MEAN THAT THERE WILL BE A HIGHER PROBABILITY OF LOSS OF LOAD?

A: It is true that there is a tradeoff between resource adequacy and costs. However, the 20% winter TRM still meets industry standard LOLE. A reduction in the TRM does not mean that Georgia Power customers would have to accept a less reliable electric supply than is available from other U.S. utilities. To provide context for this difference in capacity, under

[44] Georgia Power response to TS-STF-JKA-2-14 Attachment D.

the load forecast proposed by Georgia Power for this IRP Update, the difference between a 26% TRM and a 20% TRM is approximately 1,185 MW of winter capacity in 2028.

Q: DID YOU EVALUATE HOW A CHANGE IN THE TRM COULD IMPACT GEORGIA POWER'S CAPACITY NEEDS?

A: Yes. I also looked at Georgia Power's winter capacity position under P95 load with consideration of the difference in capacity between Georgia Power continuing to have its current winter TRM and if the winter TRM was the minimum threshold to meet the LOLE standard, which Georgia Power found to be at a reserve margin of 20%. **Table 14** shows that if one uses a 20% reserve margin and the P95 load forecast and accounts for the proposed Mississippi Power and Santa Rosa PPAs, Georgia Power has enough capacity to meet the 20% reserve margin until 2028, when the shortfall is about 633 MW.

	2024	2025	2026	2027	2028
Surplus (Shortfall) for 20% TRM	1,891	2,539	1,569	52	-633

Table 14. Georgia Power Winter Capacity Surplus (Shortfall) Under P95 Load Forecast and a 20% Reserve Margin (MW)

C. Georgia Power's Procurement of Resources

Q: PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS RELATED TO GEORGIA POWER'S PROCUREMENT OF RESOURCES.

A: I recommend that the Commission direct Georgia Power to immediately begin an expedited competitive procurement process for BESS resources. As described above, I do not believe that the Yates CTs are necessary to meet Georgia Power's capacity needs at issue in this IRP Update. So I recommend that the Commission defer consideration of the necessity of the Yates CTs until the full IRP process in 2025. Alternatively, if the Commission is inclined to approve purchasing additional capacity, I recommend the Commission direct Georgia Power to immediately begin an expedited all-source RFP process, so that the CTs can be tested against the market.

Q: CAN YOU DETERMINE HOW THE RESOURCES CHOSEN BY GEORGIA POWER IN THIS FILING COMPARE TO THE PRICES FOR SIMILAR RESOURCES IN THE MARKET?

A: No. The resources chosen by Georgia Power were not selected as a result of an RFP process, and it is unknown how these projects compare on an economic basis to the pool of projects that should be considered as resource options.

Q: CAN YOU EXPLAIN WHAT YOU MEAN WHEN YOU SAY "POOL OF PROJECTS"?

A: Yes. There are several potential projects that could be determined to be economic through an RFP process, including the projects chosen by Georgia Power in this filing, the projects that bid into the RFI issued by Georgia Power, projects that are in the interconnection queue and might have entered the queue after RFI responses were due, or possibly even projects that did not respond to the RFI but may respond to an RFP, since an RFP sends a stronger signal to potential respondents on the intention of the utility to procure capacity. In addition, as part of this filing, Georgia Power has revealed that it is evaluating additional BESS projects at the site of existing company owned or PPA solar facilities; those projects could also hypothetically respond to an RFP.[45]

Q: DO YOU HAVE ANY REASON TO BELIEVE THAT AN RFP PROCESS MAY YIELD A LOWER COST PORTFOLIO OF RESOURCES?

A: I do believe that an RFP process is the best way to ensure that the most cost effective portfolio of resources are pursued to meet capacity needs As part of my work on IRPs and certificates of public convenience and necessity ("CPCN") cases across many different jurisdictions, I have had the opportunity to participate in RFP stakeholder meetings and review RFP bid information. In some cases, utilities have conducted RFPs ahead of performing capacity expansion modeling to determine the bids to pursue and in other cases, utilities have pursued RFPs following the commencement of an IRP. In both cases, I have been able to review bid information, subject to a nondisclosure agreement. As a result, I cannot share specific values due to the confidential nature of the information, but I can say that I have seen a trend of differences in price points between PPAs and owned resources. These differences indicate there is a price premium for utility-owned resources.

Q: WHAT RECOMMENDATIONS DO YOU HAVE SPECIFIC TO THE BESS PROJECTS (INCLUDING BESS + RENEWABLE PROJECTS) THAT GEORGIA POWER HAS REQUESTED APPROVAL OF?

A: I recommend that the Commission direct Georgia Power to issue a BESS RFP as soon as possible on an expedited basis. Under the most likely load growth scenario, Georgia Power will have more than enough capacity to meet its load and a 26% reserve margin through

[45] Georgia Power response to STF-PIA-4-16 subpart d.

2026. An RFP should be issued to buy 1,410 MW of BESS resources to be deployed in 2027 and 2028. Based on the RFI results, there are at least 1,400 BESS resources that currently plan to be available by 2027 and 2028. And by issuing an expedited RFP, the projects proposed by Georgia Power could be tested against the market's ability to provide similar resources. This will ensure that the portfolio of resources selected to meet projected capacity needs will be based on an economic comparison of projects.

Q: WHAT CONCLUSIONS HAVE YOU DRAWN CONCERNING THE PLANT YATES CTS?

A: First, as described above, the CTs are not necessary to meet Georgia Power's most likely load requirements during the time frame at issue here (2024-2028).

Second, it is not reasonable for customers to buy a 45-year, 1,400 MW resource to meet the 300 MW need identified by Georgia Power's own modeling. The Aurora modeling performed as part of the resource mix study indicated that CTs were not selected as economically optimal until 2028, and the level of CTs selected in 2028 (300 MW) is substantially less than the capacity of the proposed Plant Yates CTs (1,400 MW).

Third, there is incomplete information about alternative options that could be pursued by Georgia Power. It is not clear if Georgia Power considered or evaluated the potential to site battery storage resources at the Plant Yates facility. Georgia Power's discovery responses have indicated that analysis around evaluating the potential to add BESS was related to existing PPA and company owned solar facilities. Georgia Power's testimony in this case indicated that transmission screens were only performed for resources proposed in this 2023 IRP Update (not for all possible resources outside of what Georgia Power proposed in this filing).[46] There are potential cost and transmission tradeoffs between adding CTs instead of BESS at the Plant Yates site. Adding BESS at Plant Yates would allow the project to qualify for the 10% energy community tax credit bonus under the Inflation Reduction Act since Yates' coal units were retired in 2015. This means that any BESS added at the site would qualify for an investment tax credit ("ITC") of 40%. It is also unclear if adding BESS at the Yates facility would require the same transmission upgrades

[46] Georgia Power Direct Testimony at 52.

that are needed to facilitate the addition of the proposed Yates CTs.[47] Without being able to compare the costs of the proposed Yates CTs to a BESS alternative, it is not possible to know if a strategy to build CTs instead of BESS is foregoing potential cost savings.

Q: WHAT RECOMMENDATION DO YOU HAVE FOR THE YATES CTS PROPOSED BY GEORGIA POWER IN THIS FILING?

A: The Commission should defer consideration of the need for the Yates CTs until the 2025 IRP, which is a process designed to plan for a longer time-horizon than this abbreviated IRP Update, and which will include comprehensive transmission, economic, and environmental planning. In addition, as described above, the Commission will have the benefit of additional historical information about the behavior of the new large load coming to Georgia and will also have the benefit of a new reserve margin study using the most up-to-date economic information.

In the alternative, if the Commission believes additional capacity is necessary, I recommend that the Commission direct Georgia Power to expedite the upcoming all-source RFP, which would allow Georgia Power to bid in the Yates CTs against alternative resources, such as the thermal resources proposed in Georgia Power's RFI responses and company-owned and market-driven solar and battery projects.

Q: DO YOU HAVE ANY RECOMMENDATIONS RELATED TO LANGUAGE THAT SHOULD BE INCLUDED IN THE RFP?

A: Yes. Georgia Power should include language within an all-source RFP that expressly solicits BESS project proposals at the Plant Yates facility to take advantage of the energy community bonus that would increase the ITC for those projects.

In one of its recent RFPs, Indiana Michigan Power Company ("I&M") allowed for similar projects to be proposed for its portion of the Rockport Plant site, which I&M plans to retire. I&M included this language[48] in the RFP:

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[47] In response to STF-GS-1-1 Georgia Power indicated that BESS was not studied as an option to reduce, defer, or eliminate transmission upgrades needed to facilitate the delivery of power for the proposed CTs at Plant Yates.

[48] The ownership requirement as stated in the RFP language is specific to the requirements that would have to be followed for projects to reuse the injection point when the Rockport unit retires and would not be a requirement for any new projects sited at the Yates facility since the transmission service required for the Plant Yates 1-5 was not preserved after the units retired on April 15, 2015 (Georgia Power response to STF-JKA-2-25 subpart d related to the transmission service for Plant Yates 1-5).

> *A portion of the retiring Rockport Plant site will be available for bidders to propose Combustion Turbine (CT) generation projects as well as Energy Storage projects for participation in the RFP; no other technologies will be considered at this time for the Rockport site. I&M will offer the Rockport injection point to offsite projects of any generation type, however, such proposals will need to demonstrate site control that does not introduce an unacceptable level of risk and uncertainty with respect to execution, schedule, and cost. Additionally, such projects must demonstrate compliance with all aspects of the RFP. Bids on the Rockport site or proposing to use the Rockport injection point will be limited to PSAs only; PPAs will not be considered.*[49]

Q: WHAT ARE SOME OF THE COSTS ASSOCIATED WITH THE YATES CT PROJECT?

A: The estimated in-service capital cost for the CTs is $[redacted];[50]

The transmission related costs for the Yates CTs are approximately $80,000,000.[51]

On February 14, Georgia Power supplemented its document responses and indicated that it estimated that by the end of this docket (in April 2024), if the CTs are not approved Georgia Power would still request recovery from customers of **approximately $250 million, which consists of approximately 70% development costs (already incurred) and 30% cancellation costs**.[52] (A large portion of the project development costs include [redacted].)

[49] 2023 I&M All-Source RFP at 5. Retrieved from https://imallsourcerfp.com/wp-content/uploads/2023/04/2023-IM-All-Source-RFP-3-31-23.pdf
[50] Technical Appendix 6 – "TS Technical Information Supporting the Proposal to Develop up to 1400 MW of CTs."
[51] Georgia Power response to TS-STF-DEA-4-1 Attachment.
[52] Georgia Power response to TS-STF-LA-1-23 Supplemental (Georgia Power agreed by e-mail that approximations of these figures are not Trade Secret information).
[53] Georgia Power response to TS-JKA-2-29 Attachment A at 3.

Q: IF THE COMMISSION ADOPTS YOUR RECOMMENDATION AND DEFERS CONSIDERATION OF THE PLANT YATES CTS UNTIL 2025, DO YOU AGREE WITH GEORGIA POWER'S RECOMMENDATION THAT ITS CUSTOMERS SHOULD PAY FOR THE MONEY IT HAS ALREADY SPENT ON THE CTS?

A: If the Plant Yates CTs are not approved, then Georgia Power plans to request recovery of approximately a quarter of a billion dollars.[54] I disagree with Georgia Power's request to charge existing billpayers for these expenses. Georgia Power opted to make decisions related to the proposed Plant Yates CTs outside of an economic procurement process through an RFP and it is unknown how the economics of the Plant Yates CTs compare to other resource alternatives.

V. FLEX CAPACITY FRAMEWORK AND OWNERSHIP REQUIREMENT

Q: WHAT IS THE "FLEX CAPACITY" FRAMEWORK THAT GEORGIA POWER IS REQUESTING APPROVAL OF IN THIS FILING?

A: In this filing Georgia Power is asking for approval of a "Flex Capacity" framework which would allow the Company to seek approval for additional capacity before the 2025 IRP if an updated load forecast results in projections of additional capacity needs. If an update to the load forecast presented in this filing results in a 500 MW or greater capacity, then Georgia Power would be able to recover the costs of activities related to bringing new capacity resources online. As stated in the Company's filing:

> *The Flex Capacity framework would authorize Georgia Power to undertake and recover the cost for preliminary development activities in connection with the development, operation, and ownership of new capacity resources. Additionally, the Company would be authorized to continue to explore PPA or acquisition options that could be presented for Commission approval and certification prior to the filing of the Company's 2025 IRP and recover any incremental cost incurred for this effort.*[55]

Q: DO YOU HAVE A RECOMMENDATION FOR GEORGIA POWER'S REQUEST TO RECEIVE APPROVAL FOR THE FLEX CAPACITY FRAMEWORK?

A: The Commission should deny this request. This request is unnecessary. Even if the unfathomable circumstance arose whereby the Commission denied **all** of Georgia Power's

[54] Georgia Power response to TS-STF-LA-1-23 Supplemental.
[55] Georgia Power Direct Testimony at 50 - 51.

new chosen resources **and** the statistically unlikely 95% load growth actually materialized, Georgia Power still would not need any new resources until 2026 (when it would still have enough capacity to meet its projected need plus a 23% reserve margin). Furthermore, the Flex Capacity framework authorization related to "undertake and recover the cost" concerns me given actions that Georgia Power has taken related to the proposed Plant Yates CTs and the significant costs (approximately $250 million) that could be billed to customers for their development costs prior to Commission approval. The Flex Capacity framework as proposed by Georgia Power could result in ratepayers being put in a similar situation in the future where they bear the risk of Georgia Power's expenses spent on generation resources that may not be needed to serve an expanded customer base.

VI. CONCLUSION

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
Georgia Power Company's	)	**Docket No. 55378**
2023 Integrated Resource Plan Update	)	

EXHIBIT CH-1

Chelsea Hotaling
Consultant

Professional Summary

Chelsea is a Consultant at Energy Futures Group specializing in integrated resource planning and load forecasting. Prior to joining EFG, Chelsea held a research position at Clarkson University while completing her Master's in Data Analytics and Environmental Policy & Governance. Chelsea's research focused on multi-stakeholder microgrids for resiliency. She also participated in the Reforming the Energy Vision (REV) proceedings for the Potsdam (NY) microgrid REV project. Chelsea's current work is focused on all aspects of Integrated Resource Planning including capacity expansion and production cost modeling and load forecasting. Chelsea runs the EnCompass model in support of long-term planning exercises such as IRP analyses and has critiqued IRP modeling performed using Aurora, PLEXOS, PowerSimm, and System Optimizer. Chelsea has also conducted capacity expansion, production cost, and reliability modeling using the Aurora, PLEXOS, and SERVM models. Chelsea has experience working with numerous software programs including Python, R, and Stata.

Education

M.S., Data Analytics, Clarkson University, 2020

M.S., Environmental Policy and Governance, Clarkson University, 2019

MBA, Concentration in Environmental Management, Clarkson University, 2012

B.S., Accounting and Economics, Elmira College, 2011

Experience

2021-present: Consultant, Energy Futures Group, Hinesburg, VT

2020-2021: Senior Analyst, Energy Futures Group, Hinesburg, VT

2019-2020: Analyst, Energy Futures Group, Hinesburg, VT

2018-2019: Intern, Sommer Energy, Canton, NY

2016-2019: Research Assistant, Clarkson University, Potsdam, NY

Selected Projects

- The South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Performed SERVM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Dominion Energy South Carolina 2023 IRP (2023). Performed EnCompass and SERVM modeling to evaluate a clean energy replacement portfolio as an alternative to the preferred plan presented in Santee Cooper's 2023 IRP (2023).

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Consultant

- The Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar. Performed capacity expansion and production cost modeling within EnCompass to put forward an alternate plan to DTE's preferred plan in its 2022 IRP. (2022 to 2023)
- GridLab. Performed capacity expansion and production cost modeling within EnCompass to identify resource mixes to achieve 100% emissions-free electricity by 2035 for the Public Service Company of New Mexico's electric system. (2022 to 2023)
- Sierra Club. Performed capacity expansion and production cost modeling within EnCompass to evaluate retirement and replacement of MidAmerican's coal plants. (2022 to 2023)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Appalachian Citizens' Law Center, and Mountain Association. Reviewed and provided comments on Kentucky Power's 2023 Integrated Resource Plan. (2023)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association. Reviewed and provided comments on East Kentucky Power Cooperative's 2022 Integrated Resource Plan. (2022)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association. Reviewed and provided comments on Louisville Gas & Electric and Kentucky Utilities' 2021 Integrated Resource Plan. (2022)
- The Department of Attorney General and Sierra Club. Reviewed and submitted testimony on the Aurora modeling Indiana Michigan Power Company performed for its 2021 Integrated Resource Plan. (2022)
- The Environmental Law and Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar. Performed Aurora modeling to evaluate higher levels of distributed solar for the Consumers Energy Company's 2021 Integrated Resource Plan. (2020 to 2021)
- Colorado Office of the Utility Consumer Advocate. Performed EnCompass modeling related to the Public Service Company of Colorado's 2021 Electric Resource Plan. (2021)
- Minnesota Center for Environmental Advocacy. Evaluation of Otter Tail Power's 2021 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2022 to present) Evaluated Minnesota Power's 2021 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2021 to 2022) Evaluated Xcel Energy's 2020 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2019 to 2021)
- Earthjustice. Evaluation of PREPA's request for proposals for temporary emergency generation. (May 2020) Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to 2020)
- The Council for the New Energy Economics. Reviewed and provided comments on Evergy's 2023 IRP Annual Update. (2023) Reviewed and provided comments on Evergy's 2022 IRP Annual Update. (2022) Participated in Evergy's integrated resource plan stakeholder workshops and performed EnCompass modeling to evaluate coal plant retirements (2020 to 2021).
- EfficiencyOne. Supported EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)

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- Southern Alliance for Clean Energy. Evaluation of Dominion Energy South Carolina's 2020 Integrated Resource Plan. (2020)
- Washington Electric Cooperative. Conducted the analysis for the 2020 Integrated Resource Plan. (2019 to 2020)
- Coalition for Clean Affordable Energy. Evaluated the Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station and performed EnCompass modeling to develop an alternative replacement portfolio. (2019 to 2020)
- Citizens Action Coalition of Indiana. Comments regarding Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs (May 2022). Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (March 2022) Comments regarding Southern Indiana Gas and Electric's integrated resource plans to meet future energy and capacity needs (November 2020). Comments regarding Indianapolis Power and Light's integrated resource plans to meet future energy and capacity needs (April 2020). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs. (December 2019)
- Institute for Energy Economics and Financial Analysis (IEEFA). Evaluation of National Grid's long-term natural gas capacity report. (March 2020) Evaluation of the Puerto Rico Energy Commission's proposed wheeling regulation. (March 2019) Co-author for the report Retail Choice Will Not Bring Down Puerto Rico's High Electricity Rates. (August 2018) Evaluation of the Puerto Rico Energy Commission's proposed microgrid rules. (February 2018)

Publications

Hotaling, C., Bird, S., & Heintzelman, M. D. (2021). Willingness to pay for microgrids to enhance community resilience. Energy Policy, 154, 112248.

Atems, B., & Hotaling, C. (2018). The effect of renewable and nonrenewable electricity generation on economic growth. Energy Policy, 112, 111-118.

Bird, S., & Hotaling, C. (2017). Multi-stakeholder microgrids for resilience and sustainability. Environmental Hazards, 16(2), 116-132.

Bird, S., Enayati, A., Hotaling, C., and Ortmeyer, T. (2017). Resilient Community Microgrids: Governance and Operational Challenges. In Energy Internet: An Open Energy Platform to Transform Legacy Power Systems into Open Innovation and Global Economic Engine, edited by Alex Q. Huang and Wencong Su. Elsevier.

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ENERGY FUTURES GROUP

Expert Testimony

Before the Public Service Commission of West Virginia, Case No. 23-0735-E-ENEC. *Petition and Investigation to Determine Reasonable Rates and Charges on and after January 1, 2024*. On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the South Carolina Public Service Commission, Docket No. 2023-154-E. On behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

Before the South Carolina Public Service Commission, Docket No. 2023-9-E. On behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21193. *In the Matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, and for other relief,* on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar.

Before the Kentucky Public Service Commission, Case Number 2022-00387. *In the Matter of Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC,* on behalf of Mountain Association, Kentuckians for the Commonwealth, Appalachian Citizens' Law Center, Sierra Club, and Kentucky Resources Council.

Before the Kentucky Public Service Commission, Case Number 2022-00371. *In the Matter of Electronic Tariff Filing of Kentucky Utilities Company for Approval of an Economic Development Rider Special Contract with Bitiki-KY, LLC,* on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Mountain Association, and Kentucky Resources Council.

Before the Iowa Utilities Board, Docket No. RPU-2022-0001. *Application for a Determination of Ratemaking Principle*, on behalf of Environmental Intervenors.

Before the Michigan Public Service Commission, Case No. U-21189. *In the Matter of the Application of Indiana Michigan Power Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, Avoided Costs and for Other Relief,* on behalf of Attorney General Dana Nessel and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21090. *In the Matter of the Application of Consumers Energy Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t and for Other Relief*, on behalf of the Environmental Law and Policy Center, the Ecology Center, Union of Concerned Scientists, and Vote Solar.

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Before the Public Utilities Commission of Colorado, Proceeding No. 21A-0141E. *In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan*, on behalf of the Colorado Office of the Utility Consumer Advocate.

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CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of Chelsea Hotaling on behalf of Georgia Interfaith Power & Light** was filed with the Public Service Commission in Docket No. 55378 by electronic delivery on the 15th of February, 2024. An electronic copy of same was served upon all parties listed below by electronic mail as follows:

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