

Allison W. Pryor  
allison.pryor@troutman.com

PUBLIC DISCLOSURE

March 18, 2024

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

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


Dear Ms. Tanner:

Enclosed for filing on behalf of Georgia Power Company is the (1) Rebuttal Testimony and Exhibits of the Panel of Jeffrey R. Grubb, Francisco Valle, Lee Evans, Michael B. Robinson, and Michael A. Bush, and (2) the Rebuttal Testimony of Aaron P. Abramovitz.

The Rebuttal Testimony and Exhibits of Messrs. Grubb, Valle, Evans, Robinson, and Bush is being filed under the trade secret rules of the Georgia Public Service Commission as explained in the enclosed document regarding the basis for the trade secret assertion.

Please call me at (404) 885-3779 if you have any questions regarding this filing.

Sincerely,

  
Allison W. Pryor

Enclosure

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**GEORGIA POWER COMPANY  
DOCKET NO. 55378**

**AFFIDAVIT AND BASIS FOR THE ASSERTION THAT PORTIONS OF THE  
INFORMATION SUBMITTED ARE PROTECTED TRADE SECRETS**

As part of its 2023 Integrated Resource Plan Update ("2023 IRP Update"), filed in Docket No. 55378, Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission the Rebuttal Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, Michael B. Robinson, and Michael A. Bush, which contains data supporting the 2023 IRP Load Forecast, which includes certain information regarding the Company's proprietary planning processes and load and energy forecast data assumptions, confidential customer information, and data supporting proposed Company-owned proposals, and sensitive pricing and resource cost information (the "Information"). Certain portions of the Information are trade secrets of Georgia Power and Southern Company and their affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The trade secret portions of the Information derive economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from their disclosure or use. Specifically, the trade secret portions of the Information contained herein include competitively sensitive pricing specific to the resources proposed to be developed. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. The Company's competitors are not required to reveal or publish similar information and to require the Company to do so would place it at an economic disadvantage.

Certain trade secret portions of the Information provided include load and energy forecast data assumptions such as projections of new customer load the Company has been selected to serve or the Company assesses it may be selected to serve in the near future and estimates of parameter inputs for modeling delay scenarios. Public disclosure of the Information could unfairly alter the Company's negotiation position with prospective new customers, which could result in a less advantageous rate being secured and thus potentially harming retail customers through higher rates. In addition, the Company's competitors are not required to file their respective competitive intelligence information.

The trade secret portions of the Information are subject to substantial procedures to maintain their secrecy. Only select Georgia Power and Southern Company personnel are granted access to the trade secret portions of the Information. Those personnel receive access only on a "need to know" basis. Parties outside Georgia Power and Southern Company affiliates and their legal counsel who have been granted access to the trade secret portions of the Information, if any, have been required to sign confidentiality agreements.

Jeffrey R. Grubb, first being duly sworn, deposes and states that he has reviewed the Rebuttal Testimony and that to the best of his knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. § 10-1-761 (2021).



Jeffrey R. Grubb  
Director, Resource Policy & Planning  
Georgia Power Company

Subscribed and sworn to before me this 18<sup>th</sup> day of March, 2024.



Notary Public

My Commission expires:



## PUBLIC DISCLOSURE

**STATE OF GEORGIA**

**BEFORE THE  
GEORGIA PUBLIC SERVICE COMMISSION**

**In Re:**

**Georgia Power Company's  
2023 Integrated Resource Plan Update**

Docket No. 55378

## REBUTTAL TESTIMONY OF

**JEFFREY R. GRUBB, FRANCISCO VALLE, LEE EVANS,**

MICHAEL B. ROBINSON, AND MICHAEL A. BUSH

**MARCH 18, 2024**

**REBUTTAL TESTIMONY OF  
JEFFREY R. GRUBB, FRANCISCO VALLE, LEE EVANS,  
MICHAEL B. ROBINSON, AND MICHAEL A. BUSH**

**IN SUPPORT OF GEORGIA POWER COMPANY'S  
2023 INTEGRATED RESOURCE PLAN UPDATE  
DOCKET NO. 55378**

**I. INTRODUCTION**

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

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

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

A. My name is Lee Evans. I am the Director of Economics and Load Flexibility for SCS. My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

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

A. My name is Michael A. Bush. I am the Generation Development Director for SCS. My business address is 600 North 18<sup>th</sup> Street, Birmingham, Alabama 35203.

1   **Q.    DID YOU PREVIOUSLY PRESENT DIRECT TESTIMONY ON BEHALF**  
2   **OF GEORGIA POWER IN THESE PROCEEDINGS?**

3   A.    Yes, other than Mr. Robinson, we all filed Direct Testimony in this docket on  
4        December 4, 2023.

5   **Q.    MR. ROBINSON, PLEASE SUMMARIZE YOUR EDUCATION AND**  
6   **PROFESSIONAL EXPERIENCE.**

7   A.    I graduated from Auburn University in 1993 with a Bachelor of Electrical  
8        Engineering. I began my career as a cooperative education student with Georgia  
9        Power working in distribution and marketing. After leaving the Company to serve  
10       in the United States Navy, I worked for an electric municipality in Texas, the  
11       Kerrville Public Utility Board, for five years where I was responsible for all  
12       distribution and substation facilities. In 1999, I returned to Southern Company as  
13       an engineer on the Enhanced Power Quality team with Alabama Power.  
14       Throughout my career at Southern Company, I have served in a variety of positions,  
15       including as principal engineer in Transmission Planning; supervisor of the  
16       transmission maintenance center in Albany, Georgia; supervisor of the transmission  
17       control center in Valdosta, Georgia; transmission planning manager; South Georgia  
18       area transmission manager; Metro South distribution manager; and general  
19       manager of Transmission Planning and Operations.

20       From 2017 through 2020, I served as the Power Delivery Operations General  
21       Manager for Georgia Power. I served as Planning, Operations, and Policy Vice  
22       President until January 2024, when I transitioned into my current role as Vice  
23       President of Grid Transformation, Power Delivery. In my current role, I lead an  
24       organization responsible for distribution and transmission planning, administration  
25       of the Georgia Integrated Transmission System (“ITS”), data analytics and fiber  
26       strategy, and Power Delivery compliance. I work with multiple organizations to  
27       identify the Company’s long-term transmission and distribution strategies to

1 address our future needs. I also actively engage with System and industry partners  
2 to appropriately identify industry-wide solutions, alternatives, and emerging  
3 technologies.

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

5 A. Yes, I testified before this Commission in Georgia Power’s 2022 and 2019 base  
6 rate cases in Docket Nos. 44280 and 42516, respectively, as well as in Georgia  
7 Power’s 2022 Integrated Resource Plan (“IRP”) in Docket No. 44160.

8 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

9 A. The purpose of our testimony is to respond to the testimony of the Georgia Public  
10 Service Commission (“Commission”) Public Interest Advocacy Staff (“PIA Staff”)  
11 and various Intervenor filed in Docket No. 55378. Due to the number of Parties  
12 filing testimony in this case and the limited time available to file rebuttal, our  
13 testimony focuses on several key issues without attempting to address every issue  
14 raised in PIA Staff or intervenor testimony. The fact that the Company may not  
15 respond to a particular position of PIA Staff or an intervenor should not be  
16 construed as acceptance of such position.

17 **Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR REBUTTAL**  
18 **TESTIMONY?**

19 A. Yes. In response to PIA Staff’s request that the Company file a Cost-of-Service  
20 Study (Tr. 241, lines 12–15) or something similar that shows the cost impact across  
21 rate groups (Tr. 672, lines 16–20), we have attached Exhibit 1, which shows Net  
22 Income and Return on Investment as presented in the 2022 Rate Case Test Year,  
23 distributed across each of the eight customer rate groups. Additionally, a sensitivity  
24 is included with the addition of the 2028 costs and revenues associated with  
25 investments and new loads presented in this 2023 IRP Update. Finally, a difference

1 between the two is calculated to represent the impact of such additional costs and  
2 revenues on each of the eight customer rate groups.

3 In addition, Exhibit 2 is a revised Attachment D to the Yates Certification  
4 Application updating the comparison of the proposed Yates Units 8-10 to other  
5 similar projects. Finally, Exhibit 3 is an excerpt from Lazard's 2023 Levelized Cost  
6 of Energy Analysis<sup>1</sup> identifying publicly available capital cost information for  
7 various generation technologies, including gas peaking technologies. Exhibits 2  
8 and 3 provide evidence of the reasonableness of the costs for the Yates CTs as  
9 proposed.

10 **Q. PLEASE SUMMARIZE THE REBUTTAL TESTIMONY OF THE PANEL.**

11 A. As demonstrated by the load forecast in the 2023 IRP Update, Georgia is  
12 experiencing extraordinary economic growth that has significantly impacted the  
13 magnitude and timing of Georgia Power's capacity needs. A substantial portion of  
14 this rapid economic growth is expected to occur over the next five years. The  
15 Company must act expeditiously to address the significant energy needs associated  
16 with this economic growth and to ensure it continues to maintain an electric System  
17 that can reliably meet the needs of customers and our thriving state.

18 Between the conclusion of the 2022 IRP and the filing of the 2023 IRP Update,  
19 Georgia Power was selected to serve more than 3,350 megawatts ("MW") of new,  
20 large load customers, representing approximately 34 years of traditional customer  
21 choice growth in just over one year. While substantial, this growth represents only  
22 a fraction of the potential load growth from Georgia's economic development  
23 pipeline. In fact, since the 2023 IRP Update was filed in October of 2023, the  
24 economic development pipeline has continued to grow and has now expanded to

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<sup>1</sup> <https://www.lazard.com/research-insights/2023-levelized-cost-of-energyplus/>



1 more than 21,000 MW. In addition, the Company has now been selected to serve  
2 an additional 2,602 MW since its initial filing in this proceeding. What's more,  
3 several customers representing 2,173 MW of the new large load included in the  
4 2023 IRP Update Forecast have now accelerated their load ramps, which would  
5 incorporate their entire load by 2031. These changes since October 2023 evidence  
6 the continued economic growth we are seeing in Georgia, continued customer  
7 interest in being served by Georgia Power, and the need to act now to reliably meet  
8 our customers' demand for energy as it continues to grow and accelerate. Moreover,  
9 it underscores the need to plan for a P95 load forecast, a load level supported by  
10 PIA Staff, to ensure the Company has sufficient resources to serve Georgia's  
11 substantial energy needs that are being driven by economic growth.

12 No party has reasonably challenged that the overall increase in demand is real and  
13 coming to the state. The only point of disagreement is the magnitude of the increase  
14 and the timing in which the projected large loads will materialize. PIA Staff and  
15 Intervenors alike agree with the Company's proposed methodology to account for  
16 the increase in unexpected large load customer additions and only take issue with a  
17 few assumptions, the impact of which lessens the magnitude of the growth and  
18 assumes a slower pace for load realization.

19 With the 2023 IRP Update, Georgia Power is seeking approval of approximately  
20 3,300 MW of generation capacity resources to serve its immediate growing  
21 customer demand. Specifically, the Company has requested certification of  
22 (i) 750 MW from the Mississippi Power Company ("MPC") Power Purchase  
23 Agreement ("PPA"), (ii) 230 MW from the Santa Rosa PPA, and (iii) 1,300 MW  
24 from three proposed combustion turbines ("CTs") at Plant Yates Units 8-10. The  
25 Company has also requested approval to build 1,000 MW of battery energy storage  
26 systems ("BESS"), including the Robins, Moody, and 200 MW BESS plus  
27 200 MW solar projects. In addition, the Company has proposed two new distributed  
28 energy resource ("DER") customer programs, a demand response program, and an

1 expansion of its existing residential thermostat demand program. Each of these  
2 essential capacity resources will provide an economical and reliable supply of  
3 electric power or valuable demand response for the Company's customers.  
4 Significantly, these resources are in addition to and complement the resources the  
5 Company is authorized to procure through competitive RFPs, which includes the  
6 CARES Utility Scale ("US") RFPs, All-Source Capacity RFP, and 500 MW Energy  
7 Storage System ("ESS") RFP.

8 Our rebuttal testimony addresses PIA Staff and Intervenor challenges to the  
9 Company's load forecast assumptions, the procurement of resources outside of a  
10 competitive RFP process, and the Company's proposed mix of capacity solutions.  
11 Although PIA Staff and Intervenors made several recommendations regarding  
12 Georgia Power's long-term generation and transmission planning processes, none  
13 of those recommendations need to be decided in this case. The focus of this  
14 proceeding should remain on how Georgia Power can best address the significant  
15 near-term customer demand for electric power and the corresponding capacity need  
16 between 2026 and 2028. Accordingly, much of our rebuttal testimony appropriately  
17 focuses on those pressing issues. Other matters, including the balance of PIA Staff  
18 and Intervenor recommendations, can be addressed more fully in Georgia Power's  
19 2025 IRP or a subsequent proceeding.

20 Georgia Power's 2023 IRP Update establishes a plan that ensures the Company can  
21 preserve and protect the reliability and quality of service our customers expect and  
22 continue to reliably serve Georgia's growing capacity needs corresponding to  
23 robust economic growth while also lowering rates for all retail customers by  
24 spreading the cost of electric service across a larger customer base. The Company's  
25 plan provides substantial economic and reliability benefits to the state and our  
26 customers. As such, we respectfully request the Commission approve the  
27 Company's request without modification.

1     **Q.     HOW IS YOUR TESTIMONY ORGANIZED?**

2     A.     The remainder of our testimony is structured as follows:

- 3             •     Section II discusses the timing of the 2023 IRP Update and the need to act  
4                     now, before the 2025 IRP, to request Commission approval of the new  
5                     capacity resources.
- 6             •     Section III addresses critiques of the Company's 2023 IRP Load Forecast  
7                     and assumptions incorporated into the Load Realization Model, which was  
8                     used to adjust the forecast for the projected addition of large load customers  
9                     to Georgia Power's System.
- 10            •     Section IV discusses the Staff and Intervenor feedback and  
11                    recommendations regarding the Company's ability to expedite or modify  
12                    the RFPs approved in the 2022 IRP.
- 13            •     Section V discusses Staff and Intervenor challenges to the Company's  
14                    Target Reserve Margin.
- 15            •     Section VI responds to Staff and Intervenor recommendations and critiques  
16                    of the resources requested in this case.
- 17            •     Section VII addresses the Company's transmission requests in the case and  
18                    responds to calls from Staff and Intervenor to alter its long-term  
19                    transmission planning process.

20            In addition to our testimony, the testimony of Aaron Abramovitz (i) explains why  
21            Georgia Power expects the 2023 IRP Update to place downward pressure on rates  
22            for customers, and (ii) addresses specific accounting aspects of the Company's  
23            request.

## II. THE COMPANY'S REQUEST

## Q. WHY IS THE 2023 IRP UPDATE NECESSARY?

A. As discussed in our direct testimony, the 2023 IRP Update is necessary to preserve and protect the reliability and quality of service our customers expect, address the extraordinary economic growth taking place in Georgia, and to ensure that Georgia Power can continue to reliably meet the rapidly growing energy needs of our customers and our state.

**Q. WHAT CAPACITY RESOURCES ARE NEEDED TO ENSURE THAT GEORGIA POWER CAN CONTINUE TO MEET THIS RAPID ECONOMIC GROWTH?**

A. The 2023 IRP Update seeks approval of approximately 3,300 MW of additional capacity resources so that the Company can meet the state's energy needs for the period of December of 2025 through November of 2028. Specifically, the Company has requested certification of (i) 750 MW from the MPC PPA, (ii) 230 MW from the Santa Rosa PPA, and (iii) 1,300 MW from three CTs proposed at Plant Yates, Units 8-10. The Company has also requested permission to build 1,000 MW of BESS and proposed two new DER customer programs, approval of a new demand response program, and an amendment to the certificate to expand the existing residential thermostat demand response program. The proposed resource portfolio is an economic and reliable mix of resources available to meet the capacity needs identified in this 2023 IRP Update.

**Q. HOW DOES THE COMPANY'S REQUEST FOR RESOURCES COMPARE TO THE TOTAL PIPELINE OF POTENTIAL ECONOMIC DEVELOPMENT PROJECTS IDENTIFIED IN ITS FORECAST?**

A. The Company's request for 3,300 MW corresponds to the increase and the accelerated timing in the load growth forecast, which represents only a fraction of

1 the now more than 21,000 MW of potential economic development projects seeking  
2 to meet their electricity needs.

3 **Q. CAN THE COMPANY WAIT UNTIL THE 2025 IRP TO REQUEST THESE**  
4 **RESOURCES?**

5 A. No. The magnitude and timing of the projected load that is being driven by  
6 economic growth require the Company to act now to secure the resources needed  
7 to continue to reliably serve our customers and meet our state's energy needs.  
8 Waiting until the conclusion of the 2025 IRP would be too late and would risk not  
9 being able to serve the new economic development load that is coming to Georgia.  
10 Failing to serve these new large loads would stifle economic development and  
11 prevent Georgia Power's customers from benefitting from the corresponding  
12 downward pressure on rates anticipated as a part of this 2023 IRP Update filing.

13 **Q. WHY IS IT INAPPROPRIATE TO INCLUDE A COST-OF-SERVICE**  
14 **STUDY IN THIS IRP UPDATE OR THE 2025 IRP?**

15 A. A cost-of-service study is a required aspect of base rate cases, which are the  
16 appropriate proceeding in which to determine the cost of service and allocation of  
17 those costs among rates and rate groups. The Company is not requesting to adjust  
18 rates as part of this IRP Update and a cost-of-service study is neither required nor  
19 possible. A cost-of-service study in its entirety takes multiple months and extensive  
20 Company resources to prepare. In addition, a rate case budget is required as an input  
21 to the cost-of-service study, and this information will not be finalized prior to the  
22 2025 IRP filing.

1 **Q. IS THE COMPANY OPEN TO UPDATING RELEVANT PORTIONS OF**  
2 **THE COST-OF-SERVICE STUDY THAT IT FILED IN THE 2022 BASE**  
3 **RATE CASE TO SUPPORT ITS REQUEST IN THIS CASE?**

4 A. Yes. For purposes of high-level sensitivity analysis only, the Company performed  
5 an adjustment to the cost-of-service study filed in the 2022 Base Rate Case to  
6 isolate the revenues and revenue requirement associated with the resources  
7 proposed in this case. Exhibit 1 reflects a sensitivity based on Exhibit LPE-1 from  
8 the 2022 Base Rate Case and includes the additional loads, costs and revenues  
9 associated with this filing, as requested by Staff Panel Newsome-Hayet-Wellborn  
10 during Staff Direct Hearings. The results of this sensitivity measure the benefits to  
11 customer rate groups as a result of the 2023 IRP Update by an increase to Net  
12 Income or Return on Investment (“ROI”). The results of Exhibit 1 show an increase  
13 in Net Income and improved or approximately equal ROI for each customer rate  
14 group and clearly demonstrates that customer benefit is equal or improved across  
15 the board. Since the billed revenue for non-marginal rate groups did not change as  
16 a result of the 2023 IRP Update, the results from Exhibit 1 show lower costs borne  
17 by other rate groups, which are now being allocated to the new large loads in the  
18 Marginal rate group. This allocation produces benefits for other customer rate  
19 groups, including Domestic and Small Business.

20 **Q. DID THE COMPANY FILE THE 2023 IRP UPDATE AT THE**  
21 **APPROPRIATE TIME?**

22 A. Yes. The Company filed the IRP Update at the appropriate time and as soon as  
23 reasonably possible based upon the information available to it and which was  
24 needed for Commission consideration. Until June 2023, the capacity need driven  
25 by increased growth could be met with either (1) existing Company capacity  
26 resources, including the capacity PPAs approved in the 2022 IRP, or (2) an increase  
27 in the megawatt targets for the All-Source Capacity RFP for 2029-2031. There  
28 simply was no need to consider returning to the Commission prior to June 2023,

1 when the Company's forecasting sensitivities indicated its capacity need year  
2 moved earlier by two years from winter 2028/2029 to winter 2026/2027. As further  
3 described in Section III below, once the Company determined that the capacity need  
4 advanced, it promptly took steps to alert the Commission and address that change,  
5 resulting in the 2023 IRP Update. The continued growth in the load forecast from  
6 September 2023 used in this IRP Update further accelerated the capacity need year  
7 to winter 2025/2026.

8 **Q. WHY SHOULD THE COMMISSION APPROVE THE COMPANY'S**  
9 **REQUESTS IN THE 2023 IRP?**

10 A. If approved, the Company's requests will allow it to timely meet the significant  
11 energy needs being driven by Georgia's extraordinary economic growth while also  
12 placing downward pressure on rates for the benefit of all customers. Thus, approval  
13 of the Company's request is in the best interests of our customers and our state and  
14 will help ensure Georgia Power can continue to provide safe, clean, reliable, and  
15 affordable electric service to Georgia's thriving and growing economy.

16 **III. LOAD FORECAST AND PROJECTED GROWTH**

17 **Q. WHY SHOULD THE COMMISSION HAVE CONFIDENCE IN THE 2023**  
18 **IRP UPDATE LOAD FORECAST?**

19 A. The 2023 IRP Update is informed by the latest economic trends and uses proven  
20 methods to evaluate the probability, level, and timing in which the projected load  
21 will materialize. PIA Staff and the Intervenors submitting testimony on this issue  
22 accepted the validity of the Company's organic load forecast and the statistically  
23 sound methodology used to account for the growth in new large load customers.  
24 (See, e.g., Tr. 89, lines 10-11; Tr. 1190, lines 8-9.) All indications, including direct  
25 input from customers, demonstrate that Georgia's tremendous economic growth  
26 will continue and that we must invest in new resources now to meet the state's

1 growing energy needs and preserve and protect the reliability and quality of service  
2 our customers expect.

3 The Company's forecasting methodology for large loads accounts for numerous  
4 types of uncertainty, including the potential that load will not materialize, will be  
5 delayed, or will materialize at a lower level than expected. Moreover, our forecast  
6 for large loads is based on the most recent economic trends, includes projects that  
7 have already selected Georgia Power as their electric service provider, and  
8 incorporates direct input from customers about growth in our state. As of the 2023  
9 IRP Update filing, the Company had already been chosen to serve over 3,600 MW  
10 of load from the approximately 17,000 MW pipeline of economic development —  
11 nearly 3,000 MW of which is already under construction. Since the 2023 IRP  
12 Update filing, the Company has been selected to serve an additional 2,602 MW out  
13 of the current economic development pipeline of approximately 21,000 MW. As  
14 such, the Company's forecast provides the most realistic depiction of large load  
15 growth in Georgia, and we have an extremely high degree of confidence in our  
16 forecast.

17 **Q. WITH REGARD TO THE COMPANY'S FORECAST, HOW MANY MW**  
18 **ARE ASSOCIATED WITH ACTUAL ECONOMIC DEVELOPMENT**  
19 **PROJECTS ANNOUNCED IN GEORGIA?**

20 A. Of the 51 large load customer projects included in the external adjustment to the  
21 Company's 2023 IRP Update Load Forecast, 32 projects, accounting for almost  
22 10,500 MW, have already chosen to do business in Georgia. These customers have  
23 taken concrete actions evidencing their commitment to do business in Georgia, such  
24 as purchasing or leasing property.

25 **Q. HOW MANY MW ARE ASSOCIATED WITH PROJECTS GEORGIA**  
26 **POWER HAS BEEN SELECTED TO SERVE?**



A. At the time of the filing in October 2023, 14 customers, accounting for 3,612 MW, had selected Georgia Power as their electric service provider. As of March 18, 2024, the Company has been selected to serve an additional 2,602 MW for a total of 6,214 MW. These additional 2,602 MW include 968 MW expected to be online by winter 2027/2028.

**Q. WHAT IS THE STATUS OF THE CUSTOMER CHOICE PROJECTS THE COMPANY HAS BEEN SELECTED TO SERVE WITHIN THE LOAD REALIZATION MODEL?**

A. Fourteen of the 51 projects included in the Company's load realization model in the 2023 IRP Update filing have executed a Request for Electric Service ("RFS"). As shown in Table 1 below, of these fourteen projects, nine have broken ground, four are pending construction, and only one is delayed. The thirteen projects that have broken ground or are pending construction comprise 3,546 MW of the total 3,612 MW. This evidence suggests that the biggest customer choice projects are moving forward and making progress without material delays.

**Table 1: Status of Committed Customers**

<b>DATA CENTER - 8 Total Customers</b>			
<b>5 broken ground</b>		<b>3 pending construction</b>	
	<b>MW</b>		<b>MW</b>
REDACTED	324	REDACTED	120
REDACTED	280	REDACTED	180
REDACTED	1,271	REDACTED	130
REDACTED	200		
REDACTED	240		
<b>Subtotal</b>	<b>2,315</b>	<b>Subtotal</b>	<b>430</b>
<b>INDUSTRIAL - 6 Total Customers</b>			
<b>4 broken ground</b>		<b>1 pending construction</b>	
	<b>MW</b>		<b>MW</b>
REDACTED	126	REDACTED	170
REDACTED	243		
REDACTED	60	<b>1 project delayed</b>	
REDACTED	202	REDACTED	66
<b>Subtotal</b>	<b>631</b>	<b>Subtotal</b>	<b>236</b>
<b>9 out of 14 customers have broken ground</b>	<b>2,946</b>	<b>5 out of 14 construction pending or delayed</b>	<b>666</b>

1 **Q. HOW DOES THE COMPANY USE AN RFS TO INFORM THE**  
2 **COMPANY'S DECISION THAT IT WILL BE REQUIRED TO SERVE A**  
3 **CUSTOMER?**

4 A. The RFS is a signed commitment that memorializes a customer's selection of  
5 Georgia Power as their electric service provider. RFSs have consistently been  
6 recognized to be a legally binding agreement and are routinely used in Georgia  
7 Territorial Electric Service Act ("Territorial Act") cases as evidence of customer  
8 choice.<sup>2</sup> The Company incorporates all of the new large load customers with signed  
9 RFS in the Company's adjusted Load Forecast, which serves as strong evidence  
10 supporting the Company's decision that it will be required to serve these customers.

11 **Q. WHY DOES GEORGIA POWER NEED TO PROCURE CAPACITY TO**  
12 **SERVE ADDITIONAL LOAD THAT HAS NOT YET COMMITTED TO BE**  
13 **SERVED BY GEORGIA POWER?**

14 A. Customers expect Georgia Power to be prepared to serve their load. As evidenced  
15 by our progress to date, which has led to securing 6,214 MW with committed  
16 customers, we anticipate that projects will continue to advance through various  
17 stages of economic development and ultimately continue to materialize. As  
18 mentioned previously, the economic development pipeline continues to grow and  
19 has increased to 21,000 MW since the Company filed this proceeding. Georgia  
20 Power has consistently demonstrated effectiveness in acquiring and retaining  
21 customers within a competitive market, achieving a historical win rate that exceeds  
22 70% of projects (representing approximately 90% of the associated load). This

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<sup>2</sup> See, e.g., Order for Transfer of Retail Electric Service, Docket No. 55460; Order for Transfer of Retail Electric Service, Docket No. 55473.

1 successful track record supports the inclusion of these projects in the Company's  
2 forecast and the capacity need associated with these projections.

3 **Q. DOES THE IRP UPDATE ATTEMPT TO ADDRESS ALL OF GEORGIA'S**  
4 **POTENTIAL ECONOMIC DEVELOPMENT LOAD GROWTH?**

5 A. No. The Company's forecast accounts for the fact that Georgia Power will  
6 ultimately only need to serve a portion of the large load customer projects it has  
7 identified. In August 2023, the Company identified approximately 17,000 MW of  
8 committed and potential projects, representing the full load of customers in the  
9 pipeline looking to locate or expand in Georgia through the mid-2030s. The 2023  
10 IRP Update Forecast projects that, through the winter of 2030/2031, Georgia Power  
11 will be asked to serve only 6,600 MW of new load, representing only a portion of  
12 the 17,000 MW pipeline. The amount of customer projects in the pipeline has  
13 continued to grow and now stands at more than 21,000 MW, demonstrating that  
14 Georgia's economic development success continues to attract new customer  
15 growth.

16 This IRP Update seeks authority to build or buy 3,300 MW of capacity resources  
17 to meet the Company's capacity needs from 2026-2028 and ensure the continued  
18 reliability of the electric System. Consistent with the 2022 IRP Order, the Company  
19 will continue to implement all existing RFPs and will use the All-Source RFP to  
20 source the balance of the capacity needed from 2029-2031.

21 **Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE**  
22 **INFORMATION THAT THE COMPANY PROVIDED STAFF TO ASSIST**  
23 **IN ITS EVALUATION OF THE LOAD FORECAST IN THIS CASE.**

24 A. As part of its initial filing, the Company provided short-term, long-term, peak, and  
25 load realization models; workpapers including weather data, forecast inputs, short-  
26 term model outputs, and Peak Demand aggregate and Territorial files that contain

1 final output information on peak and energy forecasts, and data supporting all charts  
2 and tables included in the filing. The Company also held a technical session, at PIA  
3 Staff's request, to help orient and familiarize PIA Staff's new consultant with  
4 Georgia Power's practices, processes, and forecasting methodology. The Company  
5 also provided guidance on how to acquire the software programs to aid in PIA  
6 Staff's and PIA Staff's consultant's analysis of the Company's data. Once acquired,  
7 the software programs are available for immediate use, and the models that were  
8 provided to PIA Staff were self-contained and able to be run upon acquisition of  
9 the software. The models shared with PIA Staff provided more information than  
10 would normally be included in a static technical appendix; these models can also  
11 be tested and used to develop PIA Staff's own comparable models. Ultimately, the  
12 Company met with PIA Staff and PIA Staff consultants to review the models and  
13 answer any questions, and to the extent PIA Staff had further questions or concerns,  
14 the Company was open to additional meetings with PIA Staff.

15 **Q. DID ANY PARTY PRESENT TESTIMONY CHALLENGING THE**  
16 **METHODOLOGY SUPPORTING THE COMPANY'S BASE FORECAST?**

17 A. No.

18 **Q. DID ANY PARTY PRESENT TESTIMONY CHALLENGING THE**  
19 **COMPANY'S METHODOLOGY FOR ADJUSTING ITS BASE LOAD**  
20 **FORECAST TO ACCOUNT FOR LARGE LOAD CUSTOMER GROWTH?**

21 A. No. In fact, PIA Staff agrees that the Company's methodology is appropriate and  
22 GIPL agrees that a new methodology was needed to account for this growth. PIA  
23 Staff and Intervenor objections regarding the load forecast are limited to the  
24 underlying assumptions on load ramp, load value, and delay.

1 **Q. WHAT WERE PIA STAFF'S RECOMMENDATIONS REGARDING THE**  
2 **ASSUMPTIONS USED IN THE LOAD REALIZATION MODEL?**

3 A. PIA Staff recommends three changes to the load realization model:

- 4 1. Use uniform load materialization probabilities for all customers, rather than  
5 assume that data centers and cryptocurrency customers will materialize at a  
6 different probability than other customer segments.
- 7 2. Use a REDACTED delay assumption for load ramp associated with data  
8 centers, rather than the REDACTED delay proposed by the Company,  
9 which is based on PIA Staff's assumption that supply chain delays and labor  
10 shortages are likely to delay data center construction timelines.
- 11 3. Increase the range of alternative futures by varying the key assumptions to  
12 produce a range of potential load additions along with a range of timing for  
13 those load additions to assess risks to the Company and customers. (Tr. 9-  
14 12.)

15 **Q. PLEASE RESPOND TO PIA STAFF'S ALLEGATION THAT THE**  
16 **COMPANY HAS NOT PROVIDED EVIDENCE TO SUPPORT ITS**  
17 **ASSUMPTION THAT DATA CENTERS AND CRYPTOCURRENCY**  
18 **CUSTOMERS WILL MATERIALIZE AT A DIFFERENT RATE THAN**  
19 **OTHER CUSTOMERS IN THE SAME INDUSTRY SEGMENT.**

20 A. The Company relied on prior experience with its 60 existing data center customers  
21 to inform the assumption that data centers and cryptocurrency customers will  
22 materialize at a different rate than other customer segments. The Company relied  
23 on the expertise of its employees who are in direct contact with existing and  
24 potential customers, including data centers, daily and who are intimately involved  
25 in the progress of these customers from the initial request for service to the date  
26 their facility is energized. The only distinction regarding the data center load  
27 anticipated in this case and the data center customers already served by Georgia

1 Power is the speed and magnitude in which the load is projected to materialize. In  
2 addition, one of Georgia Power's existing large load data center customers recently  
3 informed the Company that the load realization for two of its hyperscale data  
4 centers is approximately 80%, corroborating the Company's assumed load  
5 realization.

6 **Q. DID STAFF PROVIDE EMPIRICAL EVIDENCE TO SUPPORT**  
7 **CHANGING THE DATA CENTER AND CRYPTOCURRENCY**  
8 **CUSTOMER LOAD REALIZATION ASSUMPTION?**

9 A. No. Staff simply rejected the Company's assumption, arguing that because the  
10 Company relied only on its informed judgment, there was no reason to treat data  
11 center and cryptocurrency customers differently than customers in other segments.

12 **Q. PLEASE DISCUSS YOUR CONCERNS WITH PIA STAFF'S CHANGES**  
13 **TO THE COMPANY'S LOAD RAMP DELAY ASSUMPTION.**

14 A. PIA Staff's proposed change to the data center load ramp assumption lacks any  
15 reasonable support. Indeed, PIA Staff relied on unrelated anecdotal references from  
16 Google searches of dated construction trade press, blog posts, and a FOX 5 news  
17 article to suggest that labor shortages and supply chain issues have delayed data  
18 center construction elsewhere in the country. PIA Staff admitted during the hearing  
19 that these articles may not be the best or most accurate sources but stated that their  
20 intent in citing these articles was merely to demonstrate uncertainty. (Tr. 227-228.)  
21 However, PIA Staff's references are not specific to Georgia and are unrelated to  
22 the data centers seeking service from Georgia Power. Without justification, PIA  
23 Staff assumes that potential delays have not already been addressed by the  
24 construction timelines and load ramps of the large load customers coming to  
25 Georgia. In contrast, the Company's assumptions are based on information  
26 obtained directly from the customers developing the projects in question. These  
27 customers are best positioned to address their project timelines based on their

1 substantial industry experience and intimate knowledge of the projects themselves.  
2 Moreover, by altering the assumptions of the load realization model, PIA Staff's  
3 efforts go beyond identifying areas of uncertainty or risk. If adopted, PIA Staff's  
4 load forecast recommendations will materially impact the Company's ability to  
5 serve new large load customer projects.

6 **Q. DID STAFF USE A RANGE OF ALTERNATIVE FUTURES LIKE IT**  
7 **RECOMMENDS THE COMPANY USE?**

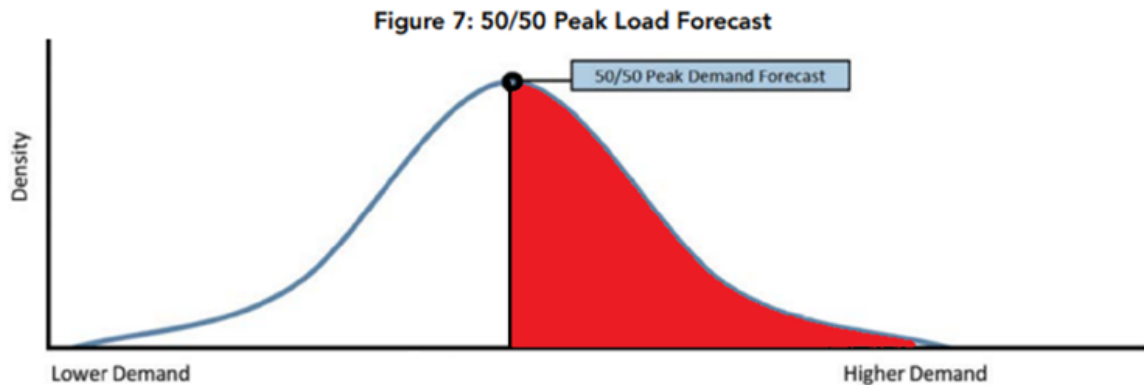
8 A. No. Staff only considered scenarios involving a delay in load and did not evaluate  
9 what the load forecast would look like if loads materialized faster than projected.  
10 Significantly, three large load customers included in the external adjustment to the  
11 Company's forecast have now requested to accelerate their load ramp – seeking  
12 2,331 MW to be served by 2031 rather than 2,173 MW by 2036 as they initially  
13 requested. In certain years, such as 2028 and 2029, this acceleration would result  
14 in approximately 800 MW of additional load than was assumed for the 2023 IRP  
15 Update Load Forecast and demonstrates the potential for substantial load to  
16 materialize at a faster pace than projected.

17 **Q. WHY WOULD IT BE INAPPROPRIATE TO USE A P50 LOAD VALUE AS**  
18 **PROPOSED BY GIPL WITNESS HOTALING?**

19 A. Planning generation resources to the P50 load value presents unacceptable risk  
20 when seeking to serve the significant large loads coming to the state. Planning to  
21 P50 can help support a slower, steady growth in load. But the load growth being  
22 experienced in Georgia is extraordinary, not slow and steady. Planning generation  
23 resources to P50 necessarily means that the Company would not have sufficient  
24 resources to meet customer needs in half of the potential scenarios for new large  
25 load customers and would thus not be able to support as much new economic  
26 development load coming to the state. Notably, GIPL used the Company's large  
27 load forecast methodology and assumptions but proposed using a P50 level load

value instead of the P95 load value used by the Company. In doing so, GIPL asserted that the P50 value is, statistically speaking, the most likely outcome and should, therefore, be used in lieu of the P95 value. Using Figure 7 from GIPL Witness Hotaling's testimony, you can see that the P50 value occurs at the peak of the bell curve on the distribution of possible outcomes. However, as shown in the modified Figure 7 graphic below, electing to use the P50 value for the large load forecast means that there is a 50% chance that loads exceed the predicted value, as seen by the red shaded area under the curve. Simply put, if Georgia Power were to plan its System using the P50 value, that would mean there is a 50% chance that it would have too few resources to meet large load customer needs, and therefore would not be able to reliably support the demands of new economic load growth.

**Figure 1: 50/50 Peak Load Forecast**



Further, the load forecast is a static snapshot in time that does not capture the fact that additional load growth is taking place. (Tr. 1312, lines 12-15.) For each new large load customer that comes onto the System, the load level previously planned for becomes less representative of the higher needs the Company must serve. (Tr. 1312-1313.) Thus, as customer load continues to grow, it is even more risky to plan according to the P50 load level than the P95 load level. This further demonstrates why it would be inappropriate to plan for the P50 load level, as recommended by



1       Witness Hotaling, than the P95 load level, which better ensures the Company has  
2       sufficient resources needed to reliably serve the growing customer demand.

3       **Q.    IS THE COMPANY WILLING TO ADOPT A TRACKING SYSTEM TO**  
4       **MONITOR MARKET ACTIVITIES AND TRACK THE STATUS AND**  
5       **OUTCOMES OF POTENTIAL LARGE LOAD CUSTOMER PROJECTS?**

6       A.    Yes. In fact, the Company began tracking this data in greater detail in 2023 in  
7       response to the extraordinary growth in the state and the increase in large load  
8       customers asking to be served by Georgia Power.

9       **Q.    PLEASE RESPOND TO STAFF AND INTERVENOR SUGGESTIONS**  
10       **THAT THE COMPANY SHOULD HAVE KNOWN EARLIER THAT**  
11       **CUSTOMER LOAD GROWTH WAS SIGNIFICANT ENOUGH TO**  
12       **REQUIRE RETURNING TO THE COMMISSION TO REQUEST**  
13       **ADDITIONAL RESOURCES.**

14       A.    The Company could not have foreseen the changes prompting the 2023 IRP Update  
15       earlier than it did. As background, in August 2021, when the Load Forecast  
16       supporting the 2022 IRP was completed, there was no indication that commercial  
17       and industrial sectors would experience the exponential growth observed in 2022  
18       and 2023. Before 2021, the Company averaged only about 100 MW of new large  
19       load economic development customers per year. This total rose to 336 MW in 2021  
20       (due to the win of a single customer), tripling the historical average, and 2,197 MW  
21       in 2022, which was 22 times the historical average. The Company first identified a  
22       new increase in projected load when it created its Budget 2023 load forecast in  
23       August 2022 as part of its annual planning process. The Budget 2023 Forecast,  
24       which was based on the latest data available at the time, identified an expected load  
25       increase of only 1,100 MW through the winter of 2030/2031, as compared to the  
26       2022 IRP filing.

1 In January 2023, following the continued increase in economic development  
2 projects, the Company began more detailed tracking of customer choice activity on  
3 a monthly basis. It also developed a model to produce load forecast sensitivities  
4 with greater frequency than the typical annual load forecast to help further inform  
5 its resource planning decisions. The load forecast sensitivities developed in June  
6 2023 identified considerable increases in projected load and, for the first time,  
7 identified an accelerated capacity need for the winter of 2026/2027.

8 To be clear, until June of 2023, all increases in projected load could be covered by  
9 existing resources or addressed by increasing the size of the 2029-2031 All-Source  
10 Capacity RFP that was approved in the 2022 IRP. Thus, it was not until June 2023  
11 that the Company detected a change in the Company's capacity need year (i.e., the  
12 year in which the Company will require additional resources moved from winter  
13 2028/2029 to winter 2026/2027). It was this change that necessitated the  
14 development of the 2023 IRP Update to procure resources to meet an even earlier  
15 capacity need beginning in the winter of 2025/2026 based on the final load forecast  
16 from September 2023.

17 **Q. HOW DO YOU RESPOND TO THE CONCERNS RAISED BY PIA STAFF**  
18 **REGARDING THE COMMISSION'S RULES FOR IRP LOAD**  
19 **FORECASTING AND THE COMPANY'S FILING IN THIS CASE?**

20 A. The Company complied with the Commission's Rules regarding the contents and  
21 validity of a load forecast. As acknowledged by PIA Staff (*See* Tr. 244, lines 10-  
22 13) and the procedural and scheduling order in this docket, the Company's IRP  
23 Update is of a limited scope. Although the Company would typically provide a high  
24 and low load growth sensitivity to the load forecast supporting the triennial IRP,  
25 the Load Realization Model used to adjust the forecast in this case for the new large  
26 load customer growth appropriately evaluated a range of outcomes and possible  
27 futures within the context of the changed circumstances the IRP Update was  
28 intended to address. The Company ran multiple load forecast sensitivities in the

1 months leading up to the IRP Update filing, each of which was provided to PIA  
2 Staff in STF-DEA-1-4. The fact that the Company analyzed the different  
3 sensitivities, chose the most reasonable load forecast to plan to, and proposed a  
4 portfolio of resource solutions to meet the need is not a failure to meet Commission  
5 rules directed at the triennial IRP filing and certainly did not prevent PIA Staff or  
6 Intervenors from proposing an alternative forecast.

7 Second, the base forecast, which captures organic growth on the System, was  
8 compiled using the same methodologies, models, and techniques as used in prior  
9 IRPs and as accurately described in the Load Forecast Technical Appendix to the  
10 2022 IRP. In addition, the Company provided alternate levels of expected growth  
11 as part of its resource mix study. A description of all load forecast determinants was  
12 provided in response to STF-JKA-2-10. The impact of self-generation and  
13 cogeneration is included in the Load Forecast Technical Appendix of the 2022 IRP,  
14 and the transparency of the Company's forecasting tools are as transparent and  
15 appropriate as they have been in every IRP since 2001. In relying on the same  
16 methodology previously used, it was not necessary to re-submit Sections 4 through  
17 6 of the Technical Appendix of the 2022 IRP. The 2023 IRP Update was  
18 appropriately focused on the Load Realization Model and forecast adjustments  
19 supporting the substantial new large loads coming to the state.

20 **Q. WHAT IS THE RISK OF ADOPTING STAFF'S RESOURCE PLAN BASED**  
21 **ON STAFF OR GIPL'S LOAD FORECAST IF MORE LOAD**  
22 **MATERIALIZES THAN THEY PROJECTED?**

23 A. If the load materializes at a rate higher than projected and outpaces the generation  
24 approved to serve that load, the Company would not be able to reliably serve its  
25 growing customer load or support Georgia's economic growth. If there is  
26 insufficient generation to support the addition of more customer load, the Company  
27 will have to stop making offers to businesses looking to locate or expand in  
28 Georgia. Customers who would otherwise locate or expand in Georgia are likely to

1 take their business elsewhere. In such case, Georgia would miss out on economic  
2 growth, and the Company and its customers would lose the opportunity to place  
3 downward pressure on rates by spreading the cost of electric service across a larger  
4 customer base.

5 **Q. CAN THE COMPANY AND THE COMMISSION MITIGATE POTENTIAL**  
6 **RISK IF THE COMMISSION ACCEPTS THE COMPANY'S PROPOSED**  
7 **PLAN BUT LESS LOAD MATERIALIZES THAN PROJECTED?**

8 A. Yes. There are several actions the Company and the Commission can take to  
9 mitigate risks associated with load materializing at a lower level than forecasted by  
10 the Company. Primarily, the Company can sell capacity in the wholesale market or  
11 slow down, reduce, or halt generation development in such a case. Other than  
12 remarketing capacity, the Company can also manage the development timeline of  
13 approved resources or the procurement amount from approved RFPs. For example,  
14 the Company can (1) reduce the amount of BESS it develops based on the  
15 unidentified balance of BESS MW in this case, and it can (2) reduce the target  
16 capacity (MW) to be procured in one or more future RFPs, including the All-Source  
17 RFP.

18 **IV. THE REQUEST FOR PROPOSAL PROCESS**

19 **Q. WHY DID THE COMPANY REQUEST AN EXCEPTION TO THE**  
20 **COMMISSION'S RFP PROCESS IN THE IRP UPDATE?**

21 A. Due to the Company's capacity need in the winters of 2025/2026, 2026/2027, and  
22 2027/2028, there simply isn't enough time to use an RFP, which typically takes two  
23 to two-and-a-half years to implement, evaluate, contract, and certify resources to  
24 meet the need. This is especially true in a constrained market with few existing  
25 resources available for contracting as additional time is needed to construct new  
26 resources and any necessary supporting transmission projects. Therefore, the

1 Company requested to procure resources pursuant to one or more of the RFP  
2 exceptions to ensure it can serve the customer load identified in its forecast and  
3 continue to maintain a reliable electric System.

4 **Q. DOES GEORGIA POWER SUPPORT THE COMMISSION'S RFP**  
5 **PROCESS?**

6 A. Yes. Georgia Power supports the Commission's RFP process and has conducted  
7 over 20 RFPs since 2006. The Company is currently developing and implementing  
8 numerous RFPs, including the All-Source Capacity RFP, CARES US RFP, the  
9 Biomass RFP, the DG RFP, and the 500 MW ESS RFP that were approved in the  
10 2022 IRP. The Company fully intends to continue implementing its current RFPs  
11 and utilizing the RFP process in procuring generation resources in the future.

12 **Q. WHY CAN'T THE COMPANY RELY ON EXISTING RFPS TO PROCURE**  
13 **THE RESOURCES REQUIRED IN THE 2023 IRP UPDATE?**

14 A. The Company needs resources online to meet the capacity need in the winters of  
15 2025/2026, 2026/2027 and 2027/2028, and the RFP process typically takes two to  
16 two-and-a-half years to identify, evaluate (including associated transmission),  
17 select, and certify capacity resources. Any new-build resources selected through  
18 such an RFP would not only have to be identified on an expedited timeline but  
19 constructed and brought online as early as November 2025 through November  
20 2027, which is simply not feasible. Moreover, there is no guarantee that the market  
21 would offer a sufficient quantity of firm, dispatchable resources in response to an  
22 RFP to provide the required capacity in the timeframe needed. Also, the existing  
23 RFPs are crucial to meeting the needs identified in the 2022 IRP for renewable  
24 energy resources, ESS resources, and capacity resources for the needs in the 2029-  
25 2031 timeframe and therefore must be conducted to best meet those specific needs.

1 **Q. STAFF WITNESS KADUK PROPOSED ADDING 500 MW OF CAPACITY**  
2 **EQUIVALENCE TO THE RESOURCE LEDGER US SCALE RFP. WHY**  
3 **WOULD THIS NOT BE APPROPRIATE?**

4 A. The Company only includes installed, planned, and committed resources in its  
5 resource ledger beginning in the year the resource is known to be in-service and for  
6 which the Company knows the resource's contribution to meeting capacity needs.  
7 It is impossible to know how many bids submitted into the CARES 2023 US RFP  
8 will be selected and will include renewable plus storage resources. There is also no  
9 guarantee the Company can fill the suggested 500 MW of storage from the portfolio  
10 of the 2023 CARES US RFP, which is the largest renewable RFP the Company has  
11 ever conducted. In addition, no Georgia Power US RFP portfolio has ever had every  
12 project achieve commercial operation at the same time, which PIA Staff Witness  
13 Kaduk acknowledged on the stand. There are risks in assuming there will be 500  
14 MW of renewable plus storage resources all online at the same time before 2028.

15 Ultimately, this decision does not have to be made in this case. The Company plans  
16 to give the appropriate capacity credit to any storage resources that are selected in  
17 the 2023 CARES US RFP. If Staff's prediction comes to fruition, the Company and  
18 the Commission can act at the time of certification, when the resources procured  
19 through the 2023 US RFP are known, to reduce the amount of capacity resources  
20 the Company needs to procure in a future RFP such as the 2029-2031 All-Source  
21 RFP.

22 **Q. PLEASE RESPOND TO THE TIMELINE OF DISCUSSIONS BETWEEN**  
23 **THE COMPANY AND STAFF PRESENTED IN THE NEWSOME, HAYET,**  
24 **WELLBORN PANEL.**

25 A. The Company always appreciates the opportunity to collaborate and work with  
26 Staff to discuss issues and possible solutions as they arise, which affirmatively  
27 evidences the constructive regulatory environment in Georgia. Although PIA

1 Staff's timeline accurately accounts for the chronology of the discussions, their  
2 presentation of what was discussed omits some important details that misconstrues  
3 the nature and timing of the Company's request.

4 PIA Staff's timeline suggests that the Company failed to notify the Commission  
5 early enough that its projected customer load had significantly increased. However,  
6 this ignores that in the 2022 IRP the Commission approved six capacity PPAs for  
7 over 2,200 MW and the All-Source RFP for needs in 2029-2031, which together  
8 would have been able to serve additional customer growth coming to the Company  
9 through 2031. As previously discussed, until June 2023 this additional load only  
10 increased the size of the Company's capacity needs in 2029 and beyond but did not  
11 advance the need year. The Company appropriately alerted the Commission of the  
12 need to act when the load forecast sensitivities first indicated an acceleration in the  
13 Company's capacity need year to winter 2026/2027.

14 PIA Staff's timeline also leaves out the Company's June 2023 proposal to divide  
15 the All-Source Capacity RFP into phases and issue an expedited "Phase 1" of the  
16 All-Source RFP in the fall of 2023. The Company proposed to shorten the RFP  
17 development timeline and to seek resources similar to those sought in the prior  
18 capacity RFP using the Commission-approved contracts from the 2022-2028  
19 Capacity RFP. In response, PIA Staff questioned (i) whether the Company had the  
20 authority to issue more than one All-Source RFP under the terms of the 2022 IRP  
21 Final Order, and (ii) the appropriateness of procuring additional resources due to  
22 increased capacity needs without vetting the revised load forecast in a proceeding  
23 with hearings and public comment. Throughout the summer, the Company  
24 responded to follow-up questions, informal data requests, exchanged regular  
25 emails, and provided substantial data to PIA Staff that was not fully captured in  
26 PIA Staff's Testimony. Even though the nature of the Company and PIA Staff's  
27 discussions prior to the filing of the 2023 IRP Update does not change the  
28 Company's requests in this case, we wanted to clarify both the Company's and PIA

1 Staff's efforts to productively investigate and address the substantial energy need  
2 facing the state.

3 **Q. DID THE COMPANY CONSIDER ISSUING AN RFI EARLIER, AS**  
4 **PROPOSED BY SIERRA CLUB?**

5 A. Yes. In the absence of a targeted, expedited Phase 1 All-Source Capacity RFP, the  
6 Company sought to issue an RFI as soon as possible to gain information regarding  
7 the availability of existing and planned capacity resources for the capacity need  
8 identified for years 2026 through 2028 (the timeframe being addressed in the  
9 Company's 2023 IRP Update) as well as for years 2029 through 2031, the time  
10 period to be addressed in the Company's 2029-2031 All-Source Capacity RFP. For  
11 the years 2026 through 2028, the RFI would be very valuable in determining if  
12 there were additional existing resources available beyond those already identified  
13 by the Company. In August 2023, the Company proposed to issue the RFI through  
14 the independent evaluator ("IE") website with the oversight of the IE that was  
15 selected for the All-Source Capacity RFP. However, delay in finalizing the IE  
16 contract led to the Company issuing the RFI on its own in September 2023 in an  
17 effort to solicit timely feedback from the market.

18 **V. TARGET RESERVE MARGIN**

19 **Q. WHAT TARGET RESERVE MARGIN DID THE COMPANY USE IN THE**  
20 **2023 IRP UPDATE?**

21 A. Consistent with the 2022 IRP Final Order, the Company used a 26% winter target  
22 reserve margin for planning purposes. Planning for 26% in the long term and 25.5%  
23 in the short term resulted in an 80% increase in reliability in the Company's 2021  
24 Reserve Margin Study as compared to a 20% reserve margin, which was the 1:10  
25 Loss of Load Expectation ("LOLE") threshold. The Company's winter target  
26 reserve margin served the state well in recent extreme weather events, such as



1 Winter Storm Elliott on Christmas Eve in 2022 and Winter Storm Heather, which  
2 occurred earlier this year on the second day of direct hearings in this case. Planning  
3 to a 26% winter target reserve margin ensures that the Company is prepared to  
4 handle reliability events such as these, even as customer behavior evolves over  
5 time. Further, maintaining a 26% target reserve margin lowers expected customer  
6 costs as compared to a 20% reserve margin per the 2021 Reserve Margin Study,  
7 which considers not only capacity costs, but also production costs and reliability  
8 costs.

9 **Q. IS THERE A GENERAL TREND IN THE INDUSTRY TOWARD WINTER**  
10 **RESERVE MARGINS?**

11 A. Yes. Several utilities are now either establishing winter reserve margins or are  
12 starting to plan for higher winter reserve margins. Duke Energy Carolinas, Duke  
13 Energy Progress, Santee Cooper, MISO, SPP, and PJM have either increased their  
14 winter target reserve margins or established winter target reserve margins in the last  
15 few years. Decreasing the Company's reserve margin would be a step in the  
16 opposite direction compared to the industry and would reduce Georgia Power's  
17 System reliability.

18 **Q. WHY IS STAFF'S PROPOSED 24.5% TARGET RESERVE MARGIN**  
19 **INAPPROPRIATE?**

20 A. Customers benefit from the enhanced reliability offered by planning to a winter  
21 target reserve margin of 26% for very little additional cost. Planning to a lower  
22 target reserve margin like the 24.5% recommended by PIA Staff reduces System  
23 reliability and does not provide substantial cost savings. If the Company planned to  
24 a 24.5% winter target reserve margin, the System's performance during extreme  
25 winter weather events like Winter Storm Elliott would have been diminished. Also,  
26 Staff's recommendation in the 2022 IRP for 24.5% sought to remove the risk of  
27 under forecasting loads from the Reserve Margin Study, while only planning for

1 risks associated with over forecasting loads. Planning for only one direction of  
2 movement on something like a load forecast is inappropriate because it fails to  
3 sufficiently capture the reliability risk. The 2023 IRP Update is itself strong  
4 evidence that loads can be higher than forecasted.

5 **Q. PLEASE RESPOND TO INTERVENOR RECOMMENDATIONS THAT**  
6 **RE-RUNNING THE RESERVE MARGIN STUDY WOULD PLACE**  
7 **DOWNWARD PRESSURE ON THE ECONOMICS OF RESOURCES**  
8 **CONSIDERED BY THE COMPANY.**

9 A. Witness Hotaling suggested that higher current capacity prices might reduce the  
10 Target Reserve Margin down to the 20% threshold for 1:10 LOLE. (Tr. 1286, lines  
11 15–17.) While capacity prices do impact the economic evaluation in a Reserve  
12 Margin Study, it would be inappropriate to update a single variable without  
13 considering how other variables may have also changed. The assumption that a  
14 higher capacity price could result in a lower Economic Optimum Reserve Margin  
15 (“EORM”) also ignores the Value at Risk component to the Company’s Reserve  
16 Margin Study, which considers the value to customers for a reserve margin higher  
17 than the EORM. The Company will update all the relevant variables and perform a  
18 full Reserve Margin Study that will be filed as part of its 2025 IRP. At that time,  
19 the impact of capacity price changes can be properly evaluated in the context of all  
20 other changes in the study, including any updates to the level of reserve margin  
21 associated with a 1:10 LOLE.

1 **Q. SHOULD THE COMPANY SIMPLY REDUCE ITS WINTER TARGET**  
2 **RESERVE MARGIN TO 20%, EQUIVALENT TO THE 1 IN 10 LOLE, AS**  
3 **RECOMMENDED BY PIA STAFF AND SOME INTERVENORS?**

4 A. No. The Company does not recommend reducing the winter target reserve margin  
5 below the 26% approved for planning purposes. Although some utilities plan to a  
6 level of reliability associated with a 1:10 LOLE, the Company considers that to be  
7 a minimum threshold, and also considers the costs and risks to customers when the  
8 target reserve margin is set. Lowering the winter target reserve margin to 20%  
9 would result in a reduced level of reliability, on par with or even below other  
10 regions that had firm load shed during recent winter events. Lowering the reserve  
11 margin to 20% would result in an 80% increase in the likelihood the Company  
12 would need to shed firm load, and the loss of firm load would be expected to be  
13 twice as severe, with a 110% higher amount of Expected Unserved Energy  
14 (“EUE”). With a 20% target reserve margin, the Company would be twice as reliant  
15 on interruptible loads and would expect higher generation production costs and  
16 purchased power costs. This lower level of reliability without consideration of costs  
17 and risks is not what the Company endeavors to provide its customers. System  
18 wide, adoption of a 20% winter planning reserve margin reduces the System  
19 capacity by approximately 1,800 MW. This 1,800 MW, embedded in the  
20 Company’s 26% winter target reserve margin, was necessary to maintain reliability  
21 during Winter Storm Elliott, and there is no evidence to the contrary.

## VI. PROPOSED RESOURCE SOLUTIONS

### *Staff Economic Analysis*

**Q. PLEASE DESCRIBE STAFF'S ECONOMIC ANALYSIS AND RESOURCE MIX ANALYSIS.**

A. PIA Staff conducted a review of the resources proposed by the Company. Their review encompassed two primary analyses – a Resource Mix Study and a Ranking Analysis – utilizing the Aurora optimization model, within the defined study period of 2024 to 2040, which was used to expedite simulation times. The Resource Mix Study was conducted to determine the optimal selection of resources. This study was also intended to address the perceived shortcomings in the Company’s economic analysis. In reevaluating the proposed resource investments, PIA Staff aimed to ascertain the necessity and economic viability of procurement of the Company’s proposed resources. The analysis purported to weigh the proposed new resources against generic candidate units. Additionally, an economic ranking analysis was carried out, positioning the Company’s identified resources on a spectrum from most to least favorable. This supplementary analysis was intended to provide the Commission with a structured reference should there be a requirement to pursue additional resources beyond the PIA Staff’s endorsement.

**Q. DOES THE COMPANY HAVE CONCERNS WITH PIA STAFF'S ECONOMIC ANALYSIS AND RESOURCE MIX STUDY USED IN THE 2023 IRP UPDATE?**

A. Yes. The Company has several reservations regarding PIA Staff's Economic Analysis and Resource Mix Study in the 2023 IRP Update. The extent of the issues signals to the Company that PIA Staff's findings are flawed and merit no consideration by the Commission. The identified discrepancies and oversights in PIA Staff's analysis are in the following key points:

- The abbreviated study duration ending in 2040 inadvertently skews results and biases the model against all new construction proposed by the Company, primarily because it fails to account for the complete operational lifespan of the proposed new construction Company-owned assets. This short study period also precipitated fundamental mistakes producing inaccurate results.
- PIA Staff's analysis relied on generic units that are not feasible for construction within the time frame of 2026-2028, yet they were assumed to be available regardless.
- The conditions set by PIA Staff only allowed for the selection of new Company-owned proposals at their explicit Commercial Operation Dates ("COD"), in stark contrast to the ongoing availability afforded to generic alternatives, which could be selected at any time. This discrepancy, combined with an error related to the incorrect entry of the CODs for Plant Yates Units 8-10, hindered the model's ability to consider the Company's proposed resources appropriately, effectively excluding Yates Units 8-10 from consideration.
- Finally, the approach taken did not consider variability of natural gas, ignoring the low and high gas price scenarios.

**Q. PLEASE EXPLAIN THE IMPACT OF THE SHORTER STUDY PERIOD.**

A. The truncated study period chosen by PIA Staff has considerable implications, not the least of which is the disregard for the long-term benefits that Company-owned assets with extended lifespans could offer customers. By arbitrarily setting 2040 as the study cutoff, PIA Staff's economic analysis fails to account for unit performance and cost savings that would accrue from assets like Plant Yates Units 8-10, the proposed BESS projects, and the proposed BESS plus Solar project—all of which are anticipated to operate beyond the end date assumed by PIA Staff.

PIA Staff's methodological oversight in adjusting for the shortened study period also introduced significant errors, particularly in the assessment of Combined Cycle units with carbon capture and sequestration ("CC with CCS"). PIA Staff's selection of a substantial volume of CC with CCS in the moderate gas, zero-dollar carbon scenario ("MG0") raises questions about the legitimacy of their analysis. By limiting the final study year to 2040 in PIA Staff's analysis, the availability of the 45Q tax credit — which is applicable only for the first 12 years of CC with CCS operation — was not correctly factored into the long-term economic model. Consequently, the stark cost increases that are expected to follow the 45Q tax credit's expiration were disregarded in PIA Staff's analysis. This oversight signifies broader analytical inaccuracies and undervalues the perceived benefits of the resources proposed by the Company, which in turn has contributed to PIA Staff's recommendation to reject these resources.

**Q. DID STAFF'S RESOURCE MIX ANALYSIS CONSIDER ADDING THE PROPOSED PLANT YATES UNITS 8-10?**

A. No. PIA Staff's analysis included a combination of errors that prevented the evaluation of Plant Yates Units 8-10 in the Resource Mix Analysis. Notably, the allowed selection dates for Plant Yates Units 8-9 and Unit 10 were incorrectly set to 1/1/2026 and 1/1/2027, respectively. In addition, there was no capacity modeled for Unit 9 in 2026, as the actual projected COD is in 2027, and only one month of capacity was modeled for Unit 8. PIA Staff artificially limited the opportunity for the model to pick Plant Yates Units 8-10 exclusively to the year of the entered selection dates and before any winter capacity contributions could be recognized by the model. Such limited parameters led to the Aurora model's optimization algorithm dismissing the Yates Units outright without sufficient consideration.

In response to hearing requests, PIA Staff acknowledged that allowing the Yates CTs the flexibility to be chosen in years beyond 2026 and 2027 would have resulted

1 in the selection of Plant Yates Unit 8 in 2028, even without extending the study  
2 period.

3 **Q. CAN GENERIC RESOURCES MEET CAPACITY NEEDS IN 2026-2028?**

4 A. No. Asserting that generic resources could meet the Company's capacity  
5 requirements in 2026-2028 is fundamentally inappropriate. Generic resources lack  
6 defined specifics such as location, transmission interconnection and deliverability,  
7 land and fuel availability, finalized engineering plans, and the necessary  
8 environmental permits.

9 The utilization of these hypothetical constructs in place of the Company's proposed  
10 projects undermines reliability, as generic resources cannot be built swiftly enough  
11 (if at all) to meet imminent capacity needs. A more reasonable approach would  
12 bypass the use of generics from 2026-2028, focusing solely on actual, executable  
13 resources.

14 **Q. DID THE COMPANY COMPLETE AN ANALYSIS CORRECTING FOR**  
15 **STAFF'S ERRORS?**

16 A. Yes. The Company modified PIA Staff's modeling, which used the Company's  
17 load forecast, to correct for the errors described above to conduct an updated  
18 analysis. Specifically, the Company's analysis extends the study period to 2058 and  
19 corrects the limitation on Plant Yates Unit 8-10 CODs. This recalibration not only  
20 rectifies the CC with CCS error but also provides a more accurate representation of  
21 new construction resource lifespans.

22 The results achieved by using PIA Staff's own model—with the Company's  
23 corrections—led to the selection of previously excluded projects, including the  
24 Robins and Moody BESS projects and Plant Yates Units 8-10. These outcomes  
25 demonstrate that these projects included in the Company's proposed portfolio of  
26 resources are economically favorable when evaluated without errors. The

1 Company's revised analysis correcting PIA Staff's modeling casts reasonable  
2 doubt on PIA Staff's initial rejection of the proposed Yates CTs and Robins and  
3 Moody BESS projects and underscores the importance of a more thorough and  
4 long-term evaluation provided by the Company's adjustments to PIA Staff's  
5 analysis.

6 *The MPC and Santa Rosa PPAs*

7 **Q. WOULD FULLY INTEGRATED, JOINT RESOURCE PLANNING WITH**  
8 **OTHER SOUTHERN COMPANY SUBSIDIARIES LIKE MPC HAVE**  
9 **NEGATED THE NEED FOR THE MPC PPA AS ALLEGED BY GAM?**

10 A. No. To be clear, we do plan jointly with other Southern Company operating  
11 companies. However, each retail operating company is subject to the oversight of  
12 a different state regulator and is ultimately responsible for maintaining the  
13 generation capacity needed to serve its customers consistent with the requirements  
14 of the state in which it operates. Indeed, GAM witness Pollock acknowledged this  
15 under cross-examination, stating that "over the long term, the notion is that each  
16 utility, each operating company [of Southern Company], should stand on its own"  
17 in terms of bringing resources online to meet their own load. (Tr. 1048, lines 810)  
18 In addition, per the terms of the IIC, a utility may retire or seek off System  
19 wholesale sales of excess capacity if in the best interest of its own customers. The  
20 Mississippi Public Service Commission directed MPC to retire 950 MW of capacity  
21 resources no longer needed to serve retail load in Mississippi. As previously  
22 explained, the MPC PPA was necessary to secure the available capacity for Georgia  
23 Power customers, and ensure that such capacity remained in the pool, dedicated to  
24 Georgia Power customers, and was not sold off the Southern Company System or  
25 otherwise retired. Had the Company not acted, Georgia Power would not have been  
26 able to ensure that these resources were available to serve our customers.



1 **Q. CERTAIN INTERVENORS EXPRESSED CONCERN ABOUT THE LACK**  
2 **OF FIRM TRANSMISSION SERVICE FOR THE SANTA ROSA PPA. DO**  
3 **YOU HAVE AN UPDATE ON THAT ISSUE?**

4 A. Yes. Georgia Power was able to secure firm transmission on the Southern  
5 Transmission System for transfer across the FPL/Southern Company interface  
6 through the Winter of 2024/2025. The Company will continue to seek firm  
7 transmission service for the remainder of term of the agreement.

8 **Q. HAS GEORGIA POWER BEEN ABLE TO REMARKET ANY MORE OF**  
9 **THE CAPACITY FROM THE MPC PPA OR SANTA ROSA PPA FOR 2024**  
10 **AND 2025?**

11 A. While no further contracts have been executed, the Company is actively engaged  
12 with and in negotiations with other entities through its agent Southern Wholesale  
13 Energy (“SWE”) for capacity sales in the years 2024 and 2025.

14 ***Proposed Yates CTs***

15 **Q. WHY SHOULD THE COMMISSION CERTIFY THE YATES CTS?**

16 A. Plant Yates Units 8-10 are critical components of the 2023 IRP Update that will  
17 provide reliable and economical peaking resources needed to ensure Georgia Power  
18 can continue to reliably meet the electricity needs of its customers and support  
19 continued economic development in Georgia. Notably, the new units will be located  
20 at the existing Plant Yates site, allowing the Company to avoid costs and other  
21 issues related to the development of a greenfield site, while taking advantage of  
22 existing site infrastructure. Moreover, the environmental conditions, fuel supply,  
23 and life cycle operation and maintenance associated with the Plant Yates site are  
24 all favorable. Plant Yates is also located in an area of the state that is continuing to  
25 see significant electrical growth. Thus, locating these new CTs in this growing area

1 provides additional reliability to the area, which has seen limited growth in  
2 generation development.

3  
4 Finally, the Yates CTs will support the continued integration and penetration of  
5 renewables and storage on the electric System. Notably, the Company's correction  
6 of PIA Staff's expansion plans resulted in the selection of Yates 8 in winter 2027  
7 and Yates 9-10 in winter 2028 as the Company proposed.

8 **Q. PLEASE RESPOND TO THE ASSERTIONS MADE BY INTERVENORS**  
9 **THAT THE COMPANY DOES NOT NEED ALL THREE OF THE YATES**  
10 **CTS IF TRANSMISSION RESTRICTS THE OUTPUT OF THE PLANT**  
11 **DURING PEAK PERIODS WITH TRANSMISSION CONTINGENCIES?**

12 A. There is only one specific transmission case where the full output of the three units  
13 was restricted. In all other scenarios, once online, all three units will be available to  
14 be economically dispatched. It is more economical to build three units  
15 consecutively to take advantage of economies of scale, especially when the  
16 expansion plan indicates a need for CTs to meet future needs. Additionally, the  
17 three CTs will be the most efficient CTs on the Southern Company System, which  
18 enables all three units to be dispatched ahead of other CTs and the Yates 6-7 steam  
19 units.

20 **Q. WHY SHOULD THE COMMISSION HAVE CONFIDENCE IN THE**  
21 **ECONOMICS OF THE PROPOSED YATES UNITS?**

22 A. Even though the proposed Yates units are being procured outside the typical RFP  
23 process, the Commission can have confidence in the economics of Plant Yates  
24 Units 8-10. The Company routinely engages with established original equipment  
25 manufacturers ("OEMs") and engineering, procurement, and construction ("EPC")  
26 firms to evaluate the costs and risks associated with projects like those proposed at  
27 Plant Yates. The expertise garnered from these engagements ensures a high level

1 of economic scrutiny and cost-effectiveness. Moreover, the Plant Yates project is  
2 strategically positioned to meet the anticipated load growth in a timely manner. As  
3 explained in the testimony of Aaron Abramovitz, the capacity additions from Plant  
4 Yates Units 8-10, in conjunction with the other resources proposed in this IRP  
5 Update and the expected energy sales' revenues, are projected to put downward  
6 pressure on rates. The combination of timely delivery through credible partnerships  
7 and the positive impact on rates underscores the economic viability of the Plant  
8 Yates Units.

9 Additionally, when comparing to publicly available information for similar  
10 technologies, the estimated costs for Plant Yates is comparable to other CTs. This  
11 is demonstrated in "TS Attachment D – Cost Comparison of Similar Projects" filed  
12 with the Yates Certification Application in this docket on January 31, 2024, as well  
13 as Exhibit 2, which provides a supplemental update to this attachment to more  
14 accurately capture the cost adjustment for one of the comparison units. In addition,  
15 the cost of Yates Units 8-10 fall within the cost range for gas peaking technologies  
16 included in Lazard's 2023 Levelized Cost of Energy Analysis attached as Exhibit  
17 3. And while there are several site-specific aspects to the costs of the proposed CTs,  
18 these references demonstrate that the Company's cost for Plant Yates Units 8-10  
19 are in line with costs of comparable CTs.

20 **Q. IS GEORGIA POWER STILL COMMITTED TO RESPONSIBLY**  
21 **TRANSITIONING ITS GENERATION FLEET TO INCLUDE MORE**  
22 **ECONOMICAL, LOW- OR ZERO- CARBON RESOURCES?**

23 A. Yes, and we will continue to work constructively with the Commission to transition  
24 the generation fleet in an economical and reliable way that is in the best interests of  
25 our customers. This commitment includes a well-balanced and diversified approach  
26 to strategically deploying clean, highly efficient, dispatchable BESS and natural  
27 gas resources, such as those proposed at Plant Yates, needed to provide reliable  
28 electric service. Significantly, we are already conducting some of the largest

1 renewable RFPs in the country and plan to continue to develop more renewable  
2 resources in the future. Specifically, updated modeling for the 2023 IRP Update  
3 indicates that adding up to approximately 10,000 MW of new renewable resources  
4 by 2035 can provide economic benefits for customers. The certification of the  
5 proposed resource plan in this IRP Update, including the Yates CTs, is a necessary  
6 component of the Company's long-term fleet transition plan while maintaining a  
7 reliable electric System to address customers' energy needs.

8 **Q. WOULD IT BE APPROPRIATE TO INCORPORATE INTO THIS IRP**  
9 **UPDATE PROPOSED ENVIRONMENTAL REGULATIONS, LIKE THE**  
10 **111 RULE, PRIOR TO FINAL APPROVAL, AS PROPOSED BY SIERRA**  
11 **CLUB?**

12 A. No. It would be inappropriate to plan for the specific requirements of a proposed  
13 environmental regulation such as the proposed 111 Rule, which would regulate  
14 greenhouse gas emissions at fossil fuel-fired power plants.

15 The Company believes that the implications of a final 111 Rule are captured within  
16 the range of carbon pressure scenarios included in the 2023 IRP Update. Since the  
17 proposed 111 Rule has yet to be finalized and state plans have not yet been  
18 developed or approved for existing unit requirements (which may take up to three  
19 years under the proposal), the Company believes that detailed analysis of the  
20 compliance options and development of the compliance strategy for the proposed  
21 111 Rule would be premature and speculative. Specifically for the requests in this  
22 2023 IRP Update, the contract periods for the PPAs with Mississippi Power and  
23 Santa Rosa Energy Center LLC end prior to the compliance dates for existing units  
24 in the proposed 111 Rule; therefore, these PPAs are not expected to be impacted by  
25 this rule. Also, BESS are not subject to the 111 Rule.

1 Based on the proposed rule, the Company expects the proposed CTs at Plant Yates  
2 to comply with the 111 Rule and does not anticipate any changes impacting the  
3 decision to request these additional resources.

4 *1,000 MW BESS – Robins, Moody, 200 MW BESS plus 200 MW Solar*

5 **Q. WHAT IS THE STATUS OF THE ROBINS, MOODY, AND 200 MW BESS**  
6 **PLUS 200 MW SOLAR PROJECTS?**

7 A. All the BESS projects proposed in this proceeding continue to move forward in  
8 order to meet a December 2026 in-service requirement. The Company issued  
9 inquiry packages to several BESS OEMs and EPC contractors. The Company is  
10 currently in the process of evaluating and finalizing contracts around these supplier  
11 options. Additionally, the Company has continued negotiations with the developer  
12 of the 200 MW BESS plus 200 MW Solar facility with the goal of having final  
13 contracts signed as soon as possible.

14 **Q. HAS THE COMPANY IDENTIFIED ANY OTHER BESS PROJECTS TO**  
15 **MEET PART OF THE 1,000 MW REQUEST IN THIS CASE?**

16 A. Yes. The Company has identified several BESS projects it is pursuing as part of the  
17 need to deploy 1,000 MW of BESS by the end of 2027 to address the capacity needs  
18 associated with serving the new load coming to Georgia.

19 **DER**

20 **Q. DOES THE COMPANY AGREE WITH PIA STAFF WITNESS KADUK'S**  
21 **PROPOSED SIZE CAP TO THE DER CUSTOMER PROGRAMS?**

22 A. No. The Company does not agree with the size cap PIA Staff Witness Kaduk  
23 recommended for DERs in the DER Co-location program. The Co-location  
24 program was designed to make more efficient use of resiliency resources that  
25 customers are bringing to provide backup power for their operations, and to incent

1 cleaner resources certified and permitted for non-emergency use. Introducing a  
2 10 MW cap would exclude a significant portion of the resiliency resources large  
3 load customers will be procuring and prevent them from being used for the benefit  
4 of all customers.

5 Further, PIA Staff recommends setting the limit on the installed DER to match the  
6 customer's annual peak load at the premises, up to, but not exceeding the program  
7 maximum DER size limit. This recommendation is inappropriate for two reasons.  
8 First, resiliency assets designed to provide full back up are typically sized with  
9 nameplate capacity exceeding peak load. This accounts for operational best practice  
10 not to run resources for extended periods at maximum output and mitigates  
11 concerns should an individual asset fail. Second, unlike resources utilized in the  
12 DRC-1 tariff Witness Kaduk references, the resources deployed through these  
13 programs will be supply side assets capable of pushing back to the grid. As a result,  
14 there is no need or basis for putting a size cap based on load.

15 **Q. PLEASE RESPOND TO GAM WITNESS POLLOCK'S RECOMMENDED**  
16 **MODIFICATIONS TO THE DER CUSTOMER PROGRAMS.**

17 A. One of GAM Witness Pollock's concerns is that the proposed tariffs do not specify  
18 the amount of the required credits/payments. He believes that this gives the  
19 Company "undue discretion" and that the "customer would have no opportunity to  
20 either vet the proposed credits/payments or seek a remedy from the Commission."  
21 (Tr. 962.) However, by not detailing the specific credit or payment within the terms  
22 of the tariff, the programs have flexibility to accommodate different types of  
23 resources, can expand to reflect additional use cases should they materialize, and  
24 are able to adjust to changing conditions. That does not mean that customers and  
25 the Commission will not have an opportunity to view or vet the values and  
26 associated calculation methodologies. In fact, each of the proposed programs and  
27 tariffs requires an additional customer agreement. The customer agreement and  
28 supporting documents will provide further details, requirements, and specifications

1 for the individual customer and resources. The resources participating in DCL-1  
2 and DCO-1 will be supply side resources subject to Commission certification and  
3 approval.

4 Witness Pollock also expressed concern about the procurement of resources in the  
5 proposed DER Co-location Program and wants to require a competitive solicitation  
6 with engagement from the customer. The Company agrees that the participating  
7 customer must be engaged in the selection of resources but does not support a  
8 requirement that each resource must be competitively sourced. A participating  
9 customer may have existing vendor relationships or specific preferences on what  
10 technologies and or companies they would like to work with outside of a  
11 competitive procurement process. In addition, the Company has already issued an  
12 RFP and selected qualified vendors for the current DER Customer Pilot. These  
13 same vendors can be utilized for the proposed DER programs.

14 **Q. DO THE DER CO-LOCATION AND CUSTOMER OWNED PROGRAMS**  
15 **EXCLUDE CARBON FREE RESOURCES?**

16 A. No. The program is designed to be resource neutral; provided that such resources  
17 are dispatchable, have a firm fuel supply, and are interconnected to transmit the  
18 energy they produce to the electric grid. This could include microgrids, fuel cells,  
19 or other carbon free resources. Ultimately, the participating customer will be  
20 responsible for determining the set of resources that meet their needs and the  
21 Company will evaluate and reflect the appropriate System value associated with  
22 those resources.

1 **Q. SHOULD THE COMPANY CONSIDER ADDING A VIRTUAL POWER**  
2 **PLANT OPTION TO ITS RESOURCE PORTFOLIO IN THIS CASE, AS**  
3 **SUGGESTED BY THE COALITION OF LOCAL GOVERNMENTS AND**  
4 **GEORGIA SOLAR ENERGY ASSOCIATION?**

5 A. No. The Company proposed expansions of existing and new distributed energy  
6 resource programs that rely on end-use or customer-sited technology. Fully  
7 leveraging additional load flexibility programs, like virtual power plants (“VPP”),  
8 will require more planning time and further operational capabilities than exist in  
9 this 2023 IRP Update. The Company is in the process of evaluating and planning  
10 demand-side programs that will be filed in the 2025 IRP, including potential VPP  
11 programs. Deriving System value from mass market load flexibility programs will  
12 require continued investment in enterprise Distributed Energy Resource  
13 Management Systems (DERMS) for visibility, predictability, and enhanced  
14 operational capabilities of these resources.

15 *Minimum Ownership*

16 **Q. SHOULD THE COMMISSION REVISE THE MINIMUM OWNERSHIP**  
17 **REQUIREMENT IN ITS RULES?**

18 A. No. The Commission’s longstanding 70/30 policy ensures System reliability and  
19 sufficient Commission oversight of the resources serving customers. Staff and  
20 Intervenors dismiss the Commission’s 70/30 rule claiming that it is outdated and  
21 does not ensure that the Company procures the least cost resources for customers.  
22 However, this ignores the fact that apart from the resources requested in this case,  
23 the vast majority of all other capacity resources since 2001 were successfully  
24 procured through an RFP process. Further, allegations that the ratio is too high and  
25 biased in favor of Company-owned resources are based on comparisons to utilities  
26 in RTOs and deregulated markets, where service reliability has been a challenge in  
27 extreme weather events. Notably, Georgia is not alone in providing a minimum



1 number of utility-owned and controlled resources to ensure a sufficient level of  
2 reliability and oversight. For example, the 70/30 ratio is comparable to that set in  
3 Virginia, where 65% of all new renewables are to be utility owned, and N.C.G.S.  
4 § 62-110.9(2)(b) in North Carolina, which provides for all new resources to be  
5 company owned except for 45% renewables and storage.

6 **VII. TRANSMISSION**

7 **Q. PLEASE CLARIFY THE COMPANY'S TRANSMISSION REQUEST IN**  
8 **THIS CASE.**

9 A. The Company requests approval of the transmission improvements necessary to  
10 accommodate the resources proposed in the 2023 IRP Update. These improvements  
11 were identified in the preliminary transmission screening analyses filed in the  
12 Technical Appendix to the 2023 IRP Update, confirmed in the Transmission  
13 Supplemental Filing, and are consistent with the types of transmission  
14 improvements typically required to accommodate new generation added to the  
15 System.

16 **Q. IS THE COMPANY REQUESTING COMMISSION APPROVAL OF EACH**  
17 **OF THE EIGHT PROJECTS LISTED IN THE TRANSMISSION**  
18 **SUPPLEMENTAL FILING?**

19 A. No. Consistent with Georgia Power's annual transmission planning processes, the  
20 Company will continue to study and reevaluate the actual transmission projects  
21 needed to bring the Yates CTs online. The eight projects identified are the slate of  
22 projects currently identified as necessary to support the Yates CTs. As the  
23 transmission system changes and additional studies are completed through  
24 established processes, it is possible that the projects necessary to bring the Yates  
25 CTs online may change or be replaced with better alternatives. This is consistent

1 with how the Company conducts its standard transmission planning process in the  
2 triennial IRP.

3 **Q. ARE THE TRANSMISSION SCREENING ANALYSES AND**  
4 **TRANSMISSION SUPPLEMENTAL FILING COMPREHENSIVE**  
5 **ENOUGH TO SUPPORT THE COMPANY'S REQUEST IN THIS CASE?**

6 A. Yes. The Company conducted initial screening analyses for the 2023 IRP Update  
7 filing at a base load level that includes all committed large loads. The Company  
8 then continued to refine the analyses for the supplemental filing with an updated  
9 load forecast that includes committed and potential large loads. Both versions of  
10 the analyses yielded the same results for transmission needs validating the  
11 comprehensive process conducted by the Company. Additionally, the Company  
12 conducted a Unit Designation Study for the Yates CTs that further validated the  
13 transmission needs.

14 **Q. DO THE TRANSMISSION LIMITATIONS ON THE PROPOSED YATES**  
15 **UNITS LIMIT DELIVERY FROM THE UNITS ALL THE TIME?**

16 A. No. The transmission upgrades required to unlock the full designated capacity of  
17 the three proposed Yates CTs only impact power delivery in peak demand periods  
18 under certain transmission contingencies. For most hours throughout the year, the  
19 new Yates CTs will be available to serve load up to the full designated capacity as  
20 soon as they come online.

21 **Q. DID THE COMPANY PROVIDE SUPPORT FOR THE 600 MW**  
22 **TEMPORARY DELIVERY LIMITATION FOR THE YATES CTS IN**  
23 **PEAK PERIODS UNTIL 2028 WHEN TRANSMISSION CONSTRAINTS**  
24 **ARE ALLEVIATED?**

25 A. Yes. As shown in the supporting studies and workpapers accompanying the  
26 Transmission Supplemental Filing on January 19, 2024, the Company provided

1 documentation of its analysis and results regarding the transmission limitations on  
2 the proposed Plant Yates CTs until required transmission improvements as listed in  
3 the Supplemental Filings are complete.

4 **Q. ARE THE PROPOSED YATES CTS SUBJECT TO TRANSMISSION**  
5 **CURTAILMENT RISK AS A RESULT OF THE COMPANY HAVING**  
6 **REQUESTED ENERGY RESOURCE INTERCONNECTION SERVICE**  
7 **RATHER THAN NETWORK RESOURCE INTERCONNECTION**  
8 **SERVICE?**

9 A. No. Since the Company's transmission planning process includes firm and future  
10 firm commitments only, there is no curtailment risk for the delivery of power from  
11 the proposed Yates CTs because of the Company's interconnection service request.  
12 This concern from Staff Witness Goggin and SREA Witness Olson represents a  
13 fundamental misunderstanding between the requests and studies for  
14 interconnection service and delivery service on the Southern Company System. As  
15 explained in the Company's response to STF-GS-2-1, neither Energy Resource  
16 Interconnection Service ("ERIS") nor Network Resource Interconnection Service  
17 ("NRIS") conveys delivery rights to a generator. Delivery service in the Southern  
18 Company System is separately requested through a transmission service request for  
19 point-to-point transmission or through the designation of the resource as a network  
20 resource for networked transmission service. The Company has already requested  
21 that Plant Yates Units 8-10 be designated as network resources and that designation  
22 study is complete.

23 The fact that transmission operators in other parts of the country and in different  
24 market structures combine interconnection and delivery service as part of a NRIS  
25 request does not signal a fundamental flaw or risk in how the Company has planned  
26 for the delivery of power from the proposed Yates CTs.

1 **Q. DOES THE COMPANY CONSIDER NON-WIRES ALTERNATIVES IN**  
2 **ITS TRANSMISSION PLANNING AND, IF SO, WHAT ALTERNATIVES**  
3 **WERE CONSIDERED IN THIS CASE?**

4 A. Yes, the Company considers non-wires alternatives in its transmission planning and  
5 has demonstrated the integration of these solutions in past projects where they  
6 added operational flexibility and were more cost effective. However, given the time  
7 constraints in this case, the Company was unable to explore all the options typically  
8 available for a given transmission constraint or deficiency as part of the  
9 transmission analyses supporting the resource requests in this case. Nevertheless,  
10 the transmission projects identified to support the Yates CTs are consistent with the  
11 typical types of projects needed to accommodate the addition of large generation  
12 resources to the System.

13 **Q. PLEASE RESPOND TO STAFF AND INTERVENOR**  
14 **RECOMMENDATIONS THAT THE COMPANY EMPLOY EMERGING,**  
15 **GRID ENHANCING TECHNOLOGIES AND NON-WIRES**  
16 **ALTERNATIVES LIKE DYNAMIC LINE RATING, GEOLOGICAL**  
17 **TPOLOGY OPTIMIZATION, FLEXIBLE AC TRANSMISSION**  
18 **SYSTEMS (“FACTS”), ETC.**

19 A. The Company already employs many of the alternative and advancing solutions  
20 that Staff and Intervenors propose where they provide value to customers. Grid  
21 Enhancing Technologies refers to a broad range of technologies, and these are  
22 considered as part of the Company’s 10-year Transmission Planning Process. For  
23 example, the Company already uses FACTS on the System through its deployment  
24 of static VAR compensators and static synchronous compensators to improve  
25 power quality and efficiency of the transmission grid. The Company has also  
26 specified the use of series reactors and series compensation as power flow control  
27 devices in addition to advanced conductors. As a standard practice and through  
28 collaboration with the Southern Company Research and Development team, the

1 Company continues to consider new types of technologies in its evaluation criteria.  
2 However, there are limitations to using some of the suggested technologies as they  
3 are not mature enough for deployment on the System, require long lead times, or  
4 are inappropriate for long term planning. To this point, dynamic line ratings  
5 (“DLR”) have the potential to enhance operational flexibility by incorporating  
6 various factors such as wind speed, temperature, load profiles, and solar irradiance.  
7 These benefits occur in real-time or near real-time conditions, however, which  
8 make it inappropriate to use DLR capabilities as a long-term planning solution  
9 because it is impossible to know today what speeds the wind will blow at or what  
10 the solar irradiance will be many years in the future. Although not a long-term  
11 planning solution, the Company is evaluating opportunities for DLR  
12 implementation under unique circumstances to provide real-time operational  
13 benefits as a temporary solution until a long-term solution can be executed.

14 **Q. DOES THE COMPANY USE AMBIENT-ADJUSTED RATINGS (“AAR”)**  
15 **IN THEIR OPERATIONS AND PLANNING PROCESSES?**

16 A. Yes. The Company uses AAR in its dynamic ampacity ratings program for  
17 transmission planning and operations planning processes that includes local  
18 parameters such as weather and wind. By use of this program, the Company equips  
19 its operators with current System conditions and minimizes risks associated with  
20 short-term, excess conductor loading. Within the Company’s transmission planning  
21 processes, the Company leverages AAR as a bridge to permanent solutions, where  
22 appropriate. These applications tend to occur in the early years of the planning  
23 horizon when there is not sufficient time to construct a project.

24 **Q. WHY DIDN’T THE COMPANY CONSIDER BATTERIES SITED CLOSE**  
25 **TO LOAD AS A TRANSMISSION SOLUTION IN THIS CASE?**

26 A. Batteries sited near load are not a practical solution or replacement for the identified  
27 transmission upgrades for several reasons. First, the battery would need to charge

1 from the grid, which causes it to act like additional load, thereby exacerbating the  
2 problem the additional resources and transmission solutions are trying to resolve.  
3 Second, a battery serving as a solution to a *transmission* contingency cannot be  
4 counted as both generation capacity and a transmission solution by planners on the  
5 Southern Company System. To serve as a transmission solution, a battery would  
6 need to be fully charged around the clock, available when and if called upon to  
7 address a contingency since contingencies can occur at any time and potentially for  
8 extended durations. Third, a 4-hour battery is not a practical solution to address  
9 transmission contingency scenarios. For example, a tornado could create an  
10 unexpected outage during hot weather conditions that lasts for a week. For batteries  
11 to resolve the transmission constraints identified in the transmission supplemental  
12 filing analysis, the transmission grid would need to have enough available capacity  
13 to charge the battery system(s), they would need to be of significant size and  
14 discharge time, and there would need to be multiple battery systems to cover the  
15 multiple contingencies across different locations identified in the analysis. The  
16 overall cost and land requirements to support battery projects that can cover  
17 extended duration outages would be cost prohibitive, especially when  
18 contemplating the relatively small magnitude of the total amount of transmission  
19 projects identified in the supplemental transmission filing. In addition, a total net  
20 present value of the battery systems versus wire solutions would need to be run to  
21 contemplate the total life-cycle costs of the two alternatives.

22 **Q. SHOULD THE COMPANY PROACTIVELY INVEST IN MORE 500 KV**  
23 **TRANSMISSION LINES ACROSS THE STATE AS RECOMMENDED BY**  
24 **STAFF WITNESS GOGGIN, SACE WITNESS PATEL, AND SREA**  
25 **WITNESS OLSON?**

26 **A.** No, not as part of its request in this case. Intervenor-proposed 500kV solutions  
27 cannot be implemented in the required timeframe and would not completely address  
28 the local area 230kV constraints identified to bring the Yates CTs online. That said,

1 the solutions proposed in the 2023 IRP Update and supplemental filings could  
2 complement future 500kV development.

3 Further, simply proposing to build more 500kV lines in the state misunderstands  
4 how transmission planning is coordinated with generation resource planning in  
5 Georgia and would result in very expensive infrastructure investment with no  
6 guarantee to alleviate known or anticipated transmission constraints. In deregulated  
7 markets, transmission owners build large transmission lines across states hoping  
8 that they have sited the infrastructure where independent power producers will seek  
9 to interconnect. In contrast, Georgia Power builds transmission as needed to deliver  
10 power from facilities that have been sited, financed, and have initiated the process  
11 of interconnecting to the System. Georgia Power's integrated approach ensures  
12 interconnections actually occur and minimizes transmission investments based  
13 upon speculation. Further, Witness Goggin's testimony seems to ignore the  
14 integrated nature of the transmission system in Georgia whereby Georgia Power  
15 jointly plans and operates the networked transmission system with the other  
16 Georgia ITS participants in the state: Georgia Transmission Corporation ("GTC")  
17 and the Municipal Electric Authority of Georgia ("MEAG").

18 In addition, adding or upgrading existing line voltage to 500 kV is not as simple as  
19 swapping out the line on existing structures. The Company requires additional  
20 rights of way access for larger voltage lines, the acquisition of which adds  
21 substantial time and cost to the process of rebuilding or retrofitting a line. Finally,  
22 Witness Goggin seems to gloss over the significant costs and time requirements  
23 associated with changing the voltage level of existing facilities, which would be  
24 additional costs borne by Georgia Power customers.

1   **Q.   PLEASE RESPOND TO THE RECOMMENDATION OF SEVERAL**  
2       **PARTIES THAT THE COMPANY IMPLEMENT A MORE HOLISTIC,**  
3       **INTEGRATED PLANNING BETWEEN TRANSMISSION AND**  
4       **GENERATION THAT IS PROACTIVE RATHER THAN REACTIVE.**

5   A.   The Company already does most of the planning improvements parties recommend.  
6       Unlike deregulated markets, which lack the insight and structural mechanisms to  
7       jointly plan transmission and generation, the Company's IRP process already  
8       holistically and intentionally considers the balance between transmission  
9       investment and generation deployment. While transmission is a significant aspect  
10      of IRP processes, long-term firm commitments by third parties under a FERC-  
11      jurisdictional Open Access Transmission Tariff ("OATT") is also a key driver in  
12      the development of transmission expansion planning. Additionally, Southern  
13      Company and Southeastern Regional Transmission Planning ("SERTP") Sponsors'  
14      transmission planning processes utilizes multi-disciplined analyses that identify  
15      System needs using least-cost and reliable solutions from all reasonably available  
16      alternatives. As an added step, the Commission reviews, regulates, and approves  
17      the Company's planning process and ensures that the assets built are reliable,  
18      economic, and in the public interest.

19   **Q.   DOES GEORGIA POWER ALREADY PARTICIPATE IN REGIONAL**  
20       **PLANNING WITH NEIGHBORING SYSTEMS?**

21   A.   Yes. That is the purpose of the SERTP organization. Georgia Power is also a  
22       Participant in the Georgia ITS with GTC, MEAG, and Dalton Utilities.



**VIII. CONCLUSION**

1

2 **Q. IN CONCLUSION, PLEASE SUMMARIZE WHY THE COMMISSION**  
3 **SHOULD APPROVE THE COMPANY'S REQUEST WITHOUT**  
4 **MODIFICATION.**

5 A. The 2023IRP Update presents a plan that will ensure Georgia Power can continue  
6 to reliably serve the state's growing capacity needs while supporting economic  
7 growth and lowering rates for all retail customers. The Company's plan provides  
8 substantial benefits for our customers and our state, and we request that the  
9 Commission approve the Company's request without modification.

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

11 A. Yes.

**EXHIBIT 1 – Cost Impact by Rate Group Sensitivity**

	<u>Domestic</u>	<u>Small Business</u>	<u>Medium Business</u>	<u>Large Business</u>	<u>Agricultural</u>	<u>Government</u>	<u>Lighting</u>	<u>Marginal</u>	<u>Total Retail</u>
<b>2022 Rate Case Test Year</b>									
Net Income	668,694	169,009	331,733	69,040	3,556	21,616	33,058	219,114	1,515,820
Return On Investment	5.21%	7.28%	9.35%	8.66%	6.31%	3.71%	7.96%	6.33%	6.31%
<i>from Exhibit LPE-1, Schedule 1.00</i>									
 <b>Adjusted with 2023 IRP Update - 2028 Costs and Revenues</b>									
Net Income	755,793	181,601	358,497	76,106	3,894	26,158	33,630	530,865	1,966,544
Return On Investment	5.51%	7.40%	9.35%	8.74%	6.47%	4.15%	8.05%	9.83%	7.18%
 <b>Difference</b>									
Net Income	87,099	12,592	26,764	7,066	338	4,542	571	311,751	450,724
Return On Investment	0.3%	0.1%	0.0%	0.1%	0.2%	0.4%	0.1%	3.5%	0.9%

**EXHIBIT 2 – Revised TS Attachment D to the Yates Certification Application****Comparison of Advanced Frame Simple-Cycle Combustion Turbine Projects - Amended Canal 3 and Grand River 2024 \$ Cost (in red)**

<b>Project</b>	<b>Plant Yates CT Units 8, 9, &amp; 10*</b>	<b>Canal 3 (ref 1,2,3)***</b>	<b>Grand River Dam Authority (ref 4,5)****</b>
Plant Capacity (MW)	1,325	350	420
Reported Completion Cost (k\$)	REDACTED	\$280,000	\$410,000
Actual Project Cost (\$/kW)	REDACTED	\$800	\$976
Reported Completion Cost (2024 k\$)**	REDACTED	\$336,375	REDACTED
Current Project Cost (2024\$/kW)**	REDACTED	\$961	REDACTED
Location	Newnan, GA	Sandwich, MA	Chouteau, OK
Site	Existing	Existing	Existing
Owner	Georgia Power Company	Stonepeak Infrastructure Partners	Grand River Dam Authority
EPC Contractor	Black and Veatch/Mitsubishi	Burns & McDonnell/Skanska USA Civil	Unknown
Commercial Operation	12/1/2026, 5/1/2027, 8/1/2027	June-2019	April-2026
Configuration	Simple Cycle CT	Simple Cycle CT	Simple Cycle CT
Turbine Technology	Mitsubishi M501 JAC	GE 7HA.02	Mitsubishi M501 JAC
Fuel Type	NG/ULSD	NG/ULSD	NG/Unknown
Emissions Control	Hot SCR	Hot SCR	Unknown

\*Yates CT cost of gas lateral and financing excluded for comparison

\*\*Values adjusted using escalation of REDACTED

\*\*\*Amended values for Canal 3 based on GDP Price Deflator | U.S. Bureau of Economic Analysis (BEA) (<https://www.bea.gov/data/prices-inflation/gdp-price-deflator>)

\*\*\*\*Amended values for Grand River to assume published cost is in nominal 2026\$

#### References

- 1) <https://gasturbine-world.com/simple-cycle-350-mw-7ha-02-peaking-plant/>
- 2) <https://www.nsenergybusiness.com/news/burns-mcdonnell-canal-3-power-plant/>
- 3) <https://www.power-eng.com/gas/gas-and-diesel-fired-canal-3-station-completed-at-cape-cod/#gref>
- 4) <https://power.mhi.com/regions/amer/news/100323>
- 5) <https://www.readfrontier.org/stories/grand-river-dam-authority-looks-to-replace-its-last-coal-fired-generator-with-a-new-410-million-project/#:~:text=The%20Grand%20River%20Dam%20Authority,River%20Energy%20Center%20in%20Choteau.>

Rebuttal Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, Michael B. Robinson, and Michael A. Bush

On behalf of Georgia Power Company

Docket No. 55378

Exhibit 2 - Page 1

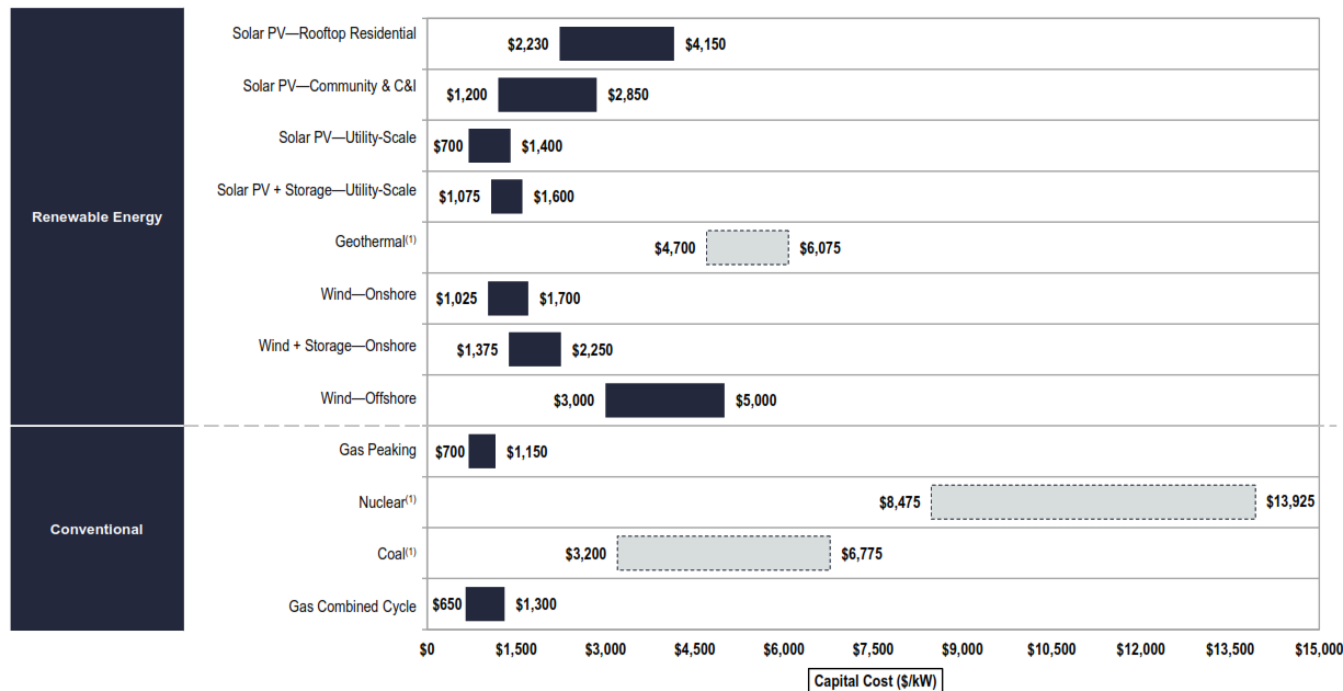
### EXHIBIT 3 – Capital Cost Comparison from Lazard’s 2023 Levelized Cost of Energy Analysis



I LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 16.0

#### Levelized Cost of Energy Comparison—Capital Cost Comparison

In some instances, the capital costs of renewable energy generation technologies have converged with those of certain conventional generation technologies, which coupled with improvements in operational efficiency for renewable energy technologies, have led to a convergence in LCOE between the respective technologies



**LAZARD**  
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Source: Lazard and Roland Berger estimates and publicly available information.

Notes: Figures may not sum due to rounding.

(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

## STATE OF GEORGIA

**BEFORE THE  
GEORGIA PUBLIC SERVICE COMMISSION**

**In Re:**

**Georgia Power Company's** )  
**2023 Integrated Resource Plan Update** )

**Docket No. 55378**

## REBUTTAL TESTIMONY OF

AARON P. ABRAMOVITZ

**MARCH 18, 2024**

**REBUTTAL TESTIMONY OF  
AARON P. ABRAMOVITZ**

**IN SUPPORT OF GEORGIA POWER COMPANY'S  
2023 INTEGRATED RESOURCE PLAN UPDATE  
DOCKET NO. 55378**

**I. INTRODUCTION**

1

2   **Q.     PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.**

3   A.     My name is Aaron P. Abramovitz. I am the Executive Vice President, Chief  
4           Financial Officer, and Treasurer for Georgia Power Company ("Georgia Power" or  
5           the "Company"). My business address is 241 Ralph McGill Boulevard N.E.,  
6           Atlanta, Georgia 30308.

7   **Q.     MR. ABRAMOVITZ, PLEASE SUMMARIZE YOUR EDUCATION AND**  
8   **PROFESSIONAL EXPERIENCE.**

9   A.     I graduated from the University of Georgia with a Bachelor of Business  
10          Administration in Finance and Management Information Systems. I joined  
11          Southern Company as a contractor in the Financial Strategy and Decision Support  
12          organization. This position was followed by a series of Financial Analyst roles in  
13          various disciplines that included Financial Planning, Financial Analysis, and  
14          Regulatory Support. From there I transitioned to Georgia Power to serve as the  
15          Coordinator for Forestry and Right of Way services. In 2008, I was assigned to the  
16          Kemper Project in Mississippi, where I served in financial leadership roles of  
17          increasing responsibility, eventually serving as the Project's Finance Director,  
18          where I was responsible for governance, reporting, regulatory support, and  
19          communications to Executives and the Board of Directors. In 2015, I returned to  
20          Atlanta to serve as the Director of Investor Relations for Southern Company, where

1 I was responsible for Southern Company's communications and relationships with  
2 the investment community. In 2018, I was named the Southern Nuclear Vogtle  
3 Units 3 and 4 Vice President of Business Operations. In this role, I had  
4 responsibility for Southern Nuclear's Project Controls, Risk Management,  
5 Budgeting and Reporting, and Commercial Analysis & Controls. I moved to my  
6 current role as Executive Vice President, Chief Financial Officer, and Treasurer for  
7 Georgia Power in September 2021. I now oversee all accounting and finance  
8 functions for the Company including financial reporting, regulatory accounting,  
9 financial planning, analysis, and enterprise risk management.

10 **Q. MR. ABRAMOVITZ, HAVE YOU PREVIOUSLY TESTIFIED BEFORE**  
11 **THE GEORGIA PUBLIC SERVICE COMMISSION ("COMMISSION")?**

12 A. Yes. I testified in the Vogtle Construction Monitoring ("VCM") proceeding,  
13 Docket No. 29849, regarding the Nineteenth, Twentieth/Twenty-first, Twenty-  
14 second, Twenty-third, and Twenty-fourth Semi-annual VCM Reports and in  
15 support of the Company's Application to Adjust Rates to Include Reasonable and  
16 Prudent Plant Vogtle Units 3 and 4 Costs in Docket No. 29849 ("Vogtle Prudence  
17 Proceeding"); the Plant Vogtle Unit 3 and Common Rate Adjustment proceeding  
18 in Docket No. 43838 ("Unit 3 Rate Adjustment"); and the Company's 2022 base  
19 rate case proceeding in Docket No. 44280 ("2022 Rate Case").

20 **Q. DID YOU PREVIOUSLY PRESENT DIRECT TESTIMONY ON BEHALF**  
21 **OF GEORGIA POWER IN THIS PROCEEDING?**

22 A. No.

23 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

24 A. My testimony (i) explains why Georgia Power projects the 2023 IRP Update to  
25 place downward pressure on rates for customers, and (ii) addresses specific  
26 accounting aspects of the Company's request.

1     **Q.     PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.**

2     A.     As outlined in the direct testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans,  
3           and Michael A. Bush (the “Company Direct Panel”), the Company is requesting,  
4           among other things, 3,300 MW of capacity resources in the form of Power Purchase  
5           Agreements (“PPAs”), three simple cycle combustion turbine (“CT”) resources at  
6           Plant Yates, and battery energy storage system (“BESS”) resources. These capacity  
7           resources are necessary to meet the substantial energy needs being driven by the  
8           extraordinary pace and magnitude of economic development in Georgia.  
9           Importantly, the Public Interest Advocacy (“PIA”) Staff and other parties to this  
10          case acknowledge that this growth is very real. As further explained by the  
11          Company Direct Panel, based on our forecast and in-depth understanding of our  
12          customers’ energy needs and plans, we are confident that this growth will  
13          materialize in the 2026-2028 timeframe, and the capacity resources requested in the  
14          Company’s 2023 IRP Update will ensure Georgia Power can continue to reliably  
15          serve our customers and support Georgia’s growing economy.

16          The 2023 IRP Update will provide substantial benefits to customers, and we expect  
17          that the revenues associated with energy sales from incremental large load  
18          customers will put downward pressure on rates for all customers, including  
19          residential and small business customers. If approved, the 2023 IRP Update is  
20          projected to provide approximately \$168 million of levelized net benefit annually  
21          for customers for 2026 through 2028, or more than \$500 million of net benefit on  
22          a cumulative basis for the three years. This benefit would put estimated downward  
23          pressure on total retail rates of approximately 1.6% as a key variable in our next  
24          base rate case filing. The Company expects that the projected revenues associated  
25          with energy sales from large load customers will exceed the revenue requirement  
26          associated with the incremental resources requested to serve the forecasted increase  
27          in peak demand materializing in 2026-2028. Downward pressure on rates would be  
28          achieved for all retail customers when, as a part of our next base rate case, Georgia



1 Power would use the net excess revenues resulting from the 2023 IRP Update to  
2 decrease the impact of other revenue requirements when calculating the requested  
3 rate adjustments.

4 The regulatory asset deferrals and additional sum requested by the Company in this  
5 case are appropriate and should be approved. The deferrals will allow the costs and  
6 benefits from the proposed resources to be concurrently recognized in the year the  
7 resources are needed. Consistent with existing regulatory assets and regulatory  
8 liabilities previously approved by this Commission, the costs related to the 2023  
9 IRP Update stem from unforeseen circumstances that could not have been  
10 accounted for during our last base rate case. These costs could not have been, nor  
11 were they, contemplated when the Commission established the Company's current  
12 base rates. The additional sum requested by the Company in this case is appropriate  
13 and consistent with the amount per kW recently approved by the Commission.

14 As acknowledged by Staff, the Company considered a wide array of federal  
15 incentives made available by the Inflation Reduction Act ("IRA") as part of its  
16 request. (Tr. 519-521.) This includes considering the IRA's Domestic Content  
17 Bonus Credit and Energy Community Bonus Credit as part of the selection of  
18 resources and identifying specific BESS projects that incorporate the benefits of the  
19 IRA. The Company will continue to pursue additional opportunities to leverage  
20 these and other federal incentives to lower costs for customers.

21 If the Commission approves the Company's request and load growth materializes  
22 as the Company expects, Georgia Power will be able to serve all of its customers—  
23 both current customers and anticipated future customers—while supporting  
24 Georgia's growing economy and related energy needs. If load growth does not  
25 materialize as expected, both the Company and the Commission have multiple  
26 levers available to manage the timing and extent of generation resources and related  
27 costs to customers.

1 In this request, Georgia Power has sought to balance the need created by projected  
2 growing peak energy demands with the timing of the generation resources  
3 necessary to support Georgia's extraordinary growth and economic development.  
4 This Commission's long-standing history of forward-thinking and constructive  
5 regulation is highly correlated to Georgia's continued ability to attract and retain  
6 businesses – ranging from technology and manufacturing to small business – and  
7 without approval from the Commission to acquire these necessary capacity  
8 resources, Georgia Power would be unable to serve its existing and growing  
9 customer base with the reliability customers value and expect.

10 At Georgia Power, our customers are at the center of everything we do, and we are  
11 unwavering in our commitment to provide them with clean, safe, reliable, and  
12 affordable energy. Approval of our 2023 IRP Update will preserve and protect the  
13 reliability and quality of service our customers expect and support the continued  
14 economic development of our state, while placing downward pressure on rates for  
15 the benefit of all customers.

16 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

17 A. In Section II of my testimony, I explain how the 2023 IRP Update will put  
18 downward pressure on rates for all of Georgia Power's customers through the  
19 projected changes to the Company's revenue requirement associated with this  
20 request. In Section III, I address several accounting matters raised by intervenors,  
21 including the appropriateness of regulatory asset treatment for certain costs, the  
22 additional sums associated with the MPC and Santa Rosa PPAs, and the federal  
23 incentives associated with the Company's BESS resource requests. Section IV sets  
24 forth my concluding remarks.

25 **II. DOWNWARD PRESSURE ON RATES FOR ALL CUSTOMERS**

26 **Q. PLEASE EXPLAIN HOW, IF APPROVED, THE 2023 IRP UPDATE WILL**  
27 **PUT DOWNWARD PRESSURE ON RATES.**

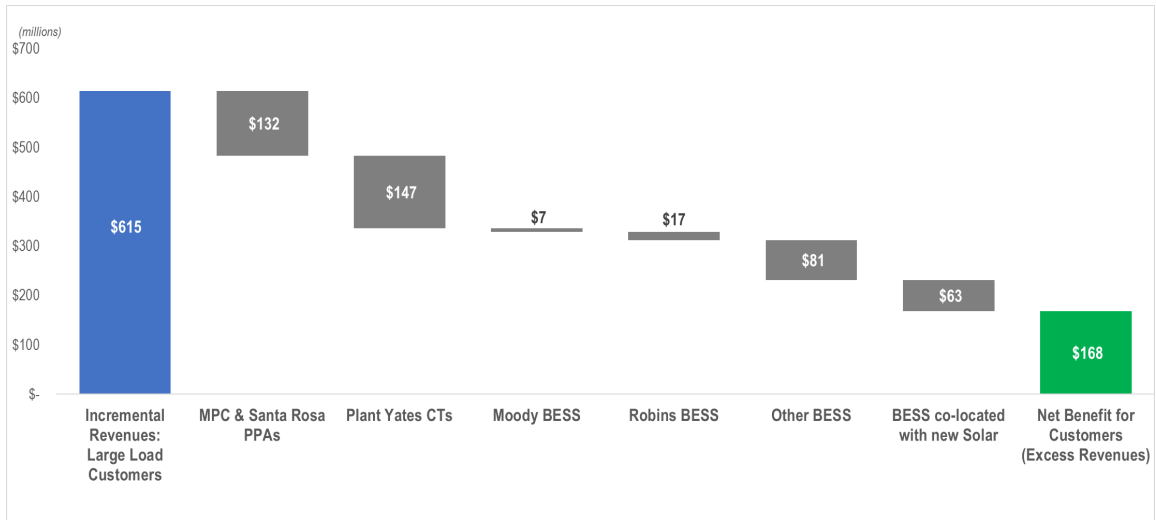
1 A. The incremental forecasted load projected in the 2023 IRP Update would result in  
2 additional revenues that will benefit all retail customers in future rate adjustments.  
3 When those revenues exceed the revenue requirement, or costs, this creates excess  
4 revenues that helps to offset other costs in the computation of rate adjustments.

5 Georgia Power filed its 2023 IRP Update to serve the extraordinary energy demand  
6 of Georgia's economic growth. Although there is a cost to serve this increased and  
7 accelerated demand, there is also a benefit that materializes through increased  
8 energy sales and revenues. In this case, with this request, the incremental revenue  
9 benefits outweigh the costs. Downward pressure on retail rates occurs when the  
10 costs associated with the resources requested in the 2023 IRP Update are more than  
11 offset by the projected energy sales' revenues associated with the large load  
12 customers.

13 **Q. HOW DOES THE 2023 IRP UPDATE IMPACT THE COMPANY'S**  
14 **REVENUE REQUIREMENT?**

15 A. As shown in Figure 1 below, in the context of Georgia Power's upcoming 2025  
16 base rate case, and assuming a three-year Alternate Rate Plan for the years 2026,  
17 2027, and 2028, the revenues from the incremental large customer loads projected  
18 by the Company are expected to exceed the revenue requirement associated with  
19 the capacity resources requested in the 2023 IRP Update. Consistent with the  
20 Company's typical practice, Georgia Power would include both the projected  
21 revenues and the costs associated with these resources when calculating the rate  
22 adjustments in our next base rate case and would use the net excess revenues related  
23 to these resources to reduce the impact of other revenue requirements, placing  
24 downward pressure on rates for all retail customers.

**Figure 1: 2023 IRP Update: Levelized Revenue Requirement Impact  
(2026 - 2028)**



**Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT COMPONENTS IN FIGURE 1.**

**A.** The amounts presented in Figure 1 represent projected net revenue requirements for 2026 through 2028 on a levelized basis. The projected retail base revenues for incremental large load customers in Figure 1 are consistent with the revenues presented in the Company's response to STF-DEA-3-6. These projected revenues include estimated energy sales growth of nearly 9% over the next three to five years, with data centers representing more than 80% of that growth based on our most recent data. The revenue requirement blocks represent the projected revenue requirements of the capacity resources proposed in the 2023 IRP Update. As depicted in Figure 1, the projected result of the incremental revenues and the revenue requirement associated with the capacity resources is a levelized net benefit to customers of approximately \$168 million, which would equate to a cumulative three-year net benefit of more than \$500 million attributable to the Company's request in the 2023 IRP Update. This \$500 million net benefit would help to offset other costs and mitigate, or lessen, rate adjustments for customers. Figure 1 clearly

1 demonstrates the basis for the Company's expected downward pressure on  
2 customer rates.

3 **Q. WHAT GIVES YOU CONFIDENCE THAT THE LOAD FROM THESE**  
4 **LARGE LOAD CUSTOMERS IS GOING TO MATERIALIZE IN THE**  
5 **2026-2028 TIMEFRAME?**

6 A. As Mr. Valle will explain further, Georgia Power's confidence is founded on robust  
7 forecasting methodologies, strong economic development activity, customer  
8 activity data, and customer commitments. The 2023 IRP Update is informed by  
9 current economic trends and utilizes established forecasting methods to predict the  
10 likelihood, scale, and timing of the projected load increases. Notably, PIA Staff and  
11 the Intervenor submitting testimony on the issue have not challenged the  
12 Company's organic load forecast and the statistical approach for anticipating  
13 growth from new large load customers. (Tr. 89, lines 10-11; Tr. 1190, lines 8-9.)

14 Georgia Power's forecast is realistic and appropriately risk adjusted. With a long-  
15 term economic development pipeline capacity of 21,000 MW in committed and  
16 potential projects by the mid-2030's, our near-term winter 2028/2029 economic  
17 development pipeline capacity is now estimated at nearly 14,200 MW, up from the  
18 11,600 MW at the time of our initial filing in October 2023. Consistent with our  
19 past practices, we are estimating that Georgia Power will ultimately serve just a  
20 portion of all anticipated economic development projects, and the 2023 IRP Update  
21 forecasts Georgia Power's winter of 2028/2029 peak demand will be approximately  
22 5,260 MW higher than the winter peak of 2023/2024.

23 At the time of our initial filing, Georgia Power was chosen by fourteen large load  
24 customers, securing agreements accounting for 3,612 MW of load, with 2,810 MW  
25 anticipated by winter 2028/2029. Nine of these projects have initiated construction,  
26 four are pending construction, and one 66 MW project is delayed. The trend of  
27 robust economic activity has continued, and since our initial filing, Georgia Power

1 has secured an additional 2,602 MW from committed customers contributing 1,647  
2 MW by winter 2028/2029. This information clearly indicates that these large load  
3 customers are materializing and will need to be served sooner rather than later.

4 All signs, including direct input from customers, support Georgia Power's  
5 expectation for continued robust economic growth in Georgia and the timing of  
6 new large customers, and further my confidence that the load from these large load  
7 customers will indeed materialize in the 2026-2028 timeframe.

8 **Q. DOES THE COMPANY'S ANALYSIS IN FIGURE 1 INCLUDE AN**  
9 **ADDITIONAL SUM AND THE DEFERRALS THE COMPANY**  
10 **REQUESTED IN 2024 AND 2025?**

11 A. Yes, our analysis includes the cost recovery of an additional sum for all five years  
12 (2024-2028), the deferral and subsequent three-year recovery of capacity and non-  
13 fuel expenses associated with the MPC and Santa Rosa PPAs, and a credit for the  
14 off-System sale of that capacity during 2024 and 2025. Importantly, Georgia Power  
15 is proposing that any additional sale of the capacity from the PPAs mentioned above  
16 would increase the net benefit to customers reflected during this period, which  
17 would further contribute to the downward pressure on rates.

18 **Q. HOW WOULD THE NET BENEFIT TO CUSTOMERS FROM THE 2023**  
19 **IRP UPDATE IMPACT TOTAL RETAIL RATES?**

20 A. Based on the current estimate, the net benefit to customers illustrated in Figure 1  
21 from the 2023 IRP Update would be equivalent to a decrease in total retail rates of  
22 1.6%.

1 **Q. HOW HAS THE COMPANY TRADITIONALLY FILED FOR RATE**  
2 **ADJUSTMENTS IN BASE RATE CASES?**

3 A. In previous base rate cases, the Company filed base tariffs whereby the adjustment  
4 was applied to each traditional base rate on an equal percentage basis.

5 **Q. HOW WOULD THE BILL FOR A TYPICAL RESIDENTIAL CUSTOMER**  
6 **BE IMPACTED IF THE NET BENEFIT TO CUSTOMERS PRESENTED IN**  
7 **THIS FILING WAS ALLOCATED TO ALL RATE GROUPS ON AN**  
8 **EQUAL PERCENTAGE BASIS?**

9 A. The Company estimates that the net benefit to customers from the 2023 IRP Update  
10 would be equivalent to a decrease of \$2.89 per month to the typical residential  
11 customer using an average of 1,000 kWh per month.

12 **Q. WILL RATES CHANGE AS PART OF THIS PROCEEDING?**

13 A. No. The Company is operating under the three-year Alternate Rate Plan approved  
14 in the 2022 Base Rate Case and is not requesting a change in rates in connection  
15 with the 2023 IRP Update. As explained above, the Company expects the increased  
16 revenues associated with the 2023 IRP Update to more than offset the cost of the  
17 resources requested in this case, and that impact would be addressed in the  
18 Company's next base rate case.

19 **Q. WHAT IS THE ESTIMATED IMPACT TO RETAIL RATES AFTER 2028**  
20 **AS A RESULT OF THE 2023 IRP UPDATE?**

21 A. With the 2023 IRP Update, the Company expects continued downward pressure on  
22 rates for all retail customers beyond 2028. If approved, the cost of the proposed  
23 resources requested in this filing would be more than offset by the revenues from  
24 the forecasted incremental load beyond 2028. Since the revenue requirement  
25 associated with the Company-owned resources is expected to decline over time, the  
26 forecasted revenues from the incremental large customer loads included in this

1 request are expected to continue to exceed the total revenue requirement of the  
2 resources included in the 2023 IRP Update.

3 **Q. WHAT LEVERS ARE AVAILABLE TO THE COMPANY AND THE**  
4 **COMMISSION TO MITIGATE THE RISK OF RATE PRESSURE IF THE**  
5 **LOAD GROWTH DOES NOT MATERIALIZE AS PROJECTED?**

6 A. Let me first reiterate that we are confident the load will materialize as projected and  
7 that the requested resources will be critical to ensuring Georgia Power is able to  
8 serve its existing and growing customer base with the reliability customers value  
9 and expect. However, even if the forecasted load does not materialize as we expect,  
10 there are multiple levers in place to mitigate the risk of upward pressure on rates.

11 The IRP framework provides ample opportunities to adjust our resource plan in  
12 subsequent IRP cycles by reducing future investments in generation resources.  
13 First, the framework allows us to adjust procurement plans for the resources  
14 requested in this proceeding based on the most recent load forecast at the time  
15 resources are submitted for certification. For example, the Company could reduce  
16 the capacity procured for 2029 through 2031 through the All-Source Capacity RFP,  
17 which was approved in the 2022 IRP. Second, the Company can make sales in the  
18 wholesale market for any capacity above its target reserve margin to reduce the cost  
19 obligation for customers, just as we did to secure off-System sale related to the  
20 MPC PPA. Third, the Company could slow, reduce, or halt the development of  
21 BESS resources if load growth is slower than expected or fails to materialize. .



1 **III. ACCOUNTING MATTERS**

2 **A. *Deferrals***

3 **Q. WHY IS THE COMPANY'S REQUEST TO DEFER CERTAIN COSTS TO**  
4 **REGULATORY ASSETS APPROPRIATE?**

5 A. The Company is seeking regulatory asset treatment for the following: (i) capacity  
6 and non-fuel energy payments made under the MPC and Santa Rosa PPAs in 2024  
7 and 2025 (including additional sum and net of amounts remarketed to third parties);  
8 (ii) non-useful and non-transferable development costs associated with the  
9 requested BESS systems and Yates Units 8-10 CTs if the Commission denies these  
10 requests; and (iii) the development costs associated with the Flex Capacity  
11 framework that would otherwise be expensed for recovery in the next base rate  
12 case. The deferral of these costs to a regulatory asset is appropriate because both  
13 the costs and benefits from these capacity resources should be concurrently  
14 recognized in the year the resources are needed. Like existing regulatory assets and  
15 regulatory liabilities that were previously approved by this Commission, the costs  
16 related to the 2023 IRP Update stem from unforeseen and extraordinary  
17 circumstances. These costs could not have been, nor were they, contemplated when  
18 the Commission established the Company's current base rates.

19 **Q. HAS THE COMMISSION ROUTINELY GRANTED DEFERRAL**  
20 **REQUESTS OUTSIDE OF A BASE RATE CASE?**

21 A. Yes. The Commission has approved deferrals to regulatory assets numerous times  
22 in an IRP. For example, in the 2019 IRP, the Commission approved deferrals for  
23 Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant  
24 Langdale Units 5-6, and Plant Riverview Units 1-2. In the 2016 IRP, the  
25 Commission approved a deferral associated with Plant Mitchell Unit 3. In the 2013  
26 IRP, the Commission approved a deferral for Plant Branch Units 3-4 and Plant

1 Boulevard Units 2-3. In the 2011 IRP Update, the Commission approved deferrals  
2 for Plant Branch Units 1-2 and Plant Mitchell Unit 4C.

3 In addition to deferrals granted in the Company's IRPs, the Commission approved  
4 cost deferrals in 2020 related to the COVID-19 pandemic, as well as the deferral  
5 and subsequent disbursement of hundreds of millions of dollars in customer refunds  
6 during 2018 and 2019 resulting from the Tax Cuts and Jobs Act. Notably, these  
7 deferrals were approved during the three-year ARP periods for items that were not  
8 contemplated in the respective base rate cases.

9 **Q. DO THE DEFERRALS REQUESTED BY THE COMPANY IN THIS CASE**  
10 **PLACE UPWARD PRESSURE ON RATES?**

11 A. No. As previously mentioned, when the incremental revenues from the additional  
12 large customer load presented in this filing are properly considered in conjunction  
13 with the total revenue requirement of the capacity resources requested in this filing,  
14 including the cost of the deferrals, the revenues are expected to exceed the revenue  
15 requirement, putting downward pressure on rates for customers.

16 These deferral requests are directly associated with the capacity resources  
17 necessary to serve our customers. Absent the efforts taken by the Company to  
18 secure these resources to serve peak demand starting in 2026, Georgia Power would  
19 be unable to serve its existing and growing customer base with the reliability  
20 customers value and expect.

21 **Q. CAN THE COMPANY WAIT UNTIL THE 2025 BASE RATE CASE TO**  
22 **MAKE A DEFERRAL REQUEST?**

23 A. No. The costs being deferred will be incurred in 2024 and 2025, and the Company  
24 will need to account for those costs in that time period. Without Commission  
25 approval to defer the costs, the Company will be required to expense these costs in  
26 the Company's financial statements during that period. The Company cannot wait

1 to request deferral treatment in the 2025 Base Rate Case because, even if the  
2 Commission were to grant the deferral in that case, the Company could not  
3 retroactively reflect the deferral treatment in its financials for the periods when the  
4 costs were incurred.

5 **B. Additional Sum**

6 **Q. ARE POWER PURCHASE AGREEMENTS REQUIRED TO BE**  
7 **PROCURED THROUGH AN RFP TO QUALIFY FOR AN ADDITIONAL**  
8 **SUM?**

9 A. No. The IRP Act authorizes an additional sum on any long-term power purchase,  
10 and only instructs the Commission to consider lost revenues, if any, changed risks,  
11 and an equitable sharing of benefits between the utility and its retail customers  
12 when setting the additional sum. The purpose of the additional sum is to provide an  
13 incentive to the Company to encourage long-term power purchases in lieu of  
14 building or buying generation assets on which it can earn a return. Contrary to  
15 Georgia Association of Manufacturers Witness Pollock's assertion that the  
16 statutory criteria for the Company to recover an additional sum is unmet, it is not a  
17 requirement that the Company procure the purchased power through an RFP for it  
18 to be eligible for an additional sum. More importantly, the additional sum incents  
19 the Company to act for the benefit of its customers to secure capacity, whether  
20 Company-owned or power purchases, when that capacity is needed. This is exactly  
21 what the Company has done in this case.

22 **Q. WHY IS IT APPROPRIATE FOR THE COMPANY TO RECOVER THE**  
23 **ADDITIONAL SUMS ASSOCIATED WITH THE MPC AND SANTA ROSA**  
24 **PPAS?**

25 A. The MPC and Santa Rosa PPAs are needed to serve Georgia Power customers.  
26 Commission Staff acknowledges this fact. (Tr. 248, lines 11-12; 297, line 10; 298,  
27 lines 1-3.) The Company's request for an additional sum in this case is consistent

1 with the treatment of other Georgia Power long-term power purchases needed to  
2 serve our customers' capacity needs. Further, the amount per kW-year requested is  
3 consistent with what was approved by the Commission for the six capacity PPAs  
4 certified in the 2022 IRP, of which, five were affiliated PPAs. Although some  
5 Intervenors have argued that the Company should not receive an additional sum for  
6 a PPA with an affiliate (Tr. 939, lines 21-23), there is no statutory restriction on the  
7 Company's ability to receive an additional sum for a long-term power purchase  
8 with an affiliate. To the contrary, Commission practice has been to routinely allow  
9 additional sums for affiliate PPAs.

10 **C. Federal Incentives**

11 **Q. WHAT FEDERAL INCENTIVES DID THE COMPANY CONSIDER AS**  
12 **PART OF ITS REQUEST?**

13 A. The Company considered a wide array of federal incentives as part of its request.  
14 As stated by Staff Witnesses Smith and Deitchman in their testimony, "the  
15 Company was aware of and considered many of the tax incentives that have been  
16 made available by the IRA." (Tr. 484, lines 19-20.) Witnesses Smith and  
17 Deitchman also acknowledged this during the February 28 hearing. (Tr. 624, lines  
18 13-15.) They note that the Company considered the IRA's Domestic Content Bonus  
19 Credit and Energy Community Bonus Credit as part of the selection of resources  
20 and identified the BESS projects that incorporate the benefits of the IRA (Tr. 520-  
21 521.) Specifically, these projects, some of which include co-located solar projects,  
22 qualify for certain investment tax credits and production tax credits, the benefit of  
23 which were included in the Company's economic evaluation for the 2023 IRP  
24 Update.

1 **Q. WILL THE COMPANY PURSUE ADDITIONAL OPPORTUNITIES TO**  
2 **LEVERAGE FEDERAL INCENTIVES?**

3 A. Yes. The Company is continually pursuing new and evolving opportunities to  
4 leverage federal incentives, including financing through DOE Loan Guarantees, tax  
5 incentives, and other credits to lower costs for customers.

6 **IV. CONCLUSION**

7 **Q. WHY SHOULD THE COMMISSION APPROVE THE COMPANY'S**  
8 **REQUEST AS FILED?**

9 A. At Georgia Power, the customer is at the center of everything we do. We are  
10 unwavering in our commitment to provide our customers with clean, safe, reliable,  
11 and affordable energy. Our request in this 2023 IRP Update seeks to continue  
12 delivering on our customer commitment, as the forecasted load growth and  
13 resulting need for additional capacity presents a significant opportunity to continue  
14 to reliably serve our customers. Approval of our 2023 IRP Update will preserve  
15 and protect the valuable reliability and quality of service both our current and future  
16 customers expect and will support the continued economic development of  
17 Georgia, while placing downward pressure on rates for the benefit of all customers.

18 Georgia's continued ability to attract and retain businesses - ranging from  
19 technology and manufacturing to small business - is highly correlated to the  
20 Commission's long-standing history of forward-thinking and constructive  
21 regulation, which facilitates Georgia Power's ability to provide customers with  
22 clean, safe, reliable, and affordable energy. We respectfully request that the  
23 Commission approve the Company's 2023 IRP Update without modification.

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

25 A. Yes.

## CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing REBUTTAL TESTIMONY OF THE PANEL OF JEFFREY R. GRUBB, FRANCISCO VALLE, LEE EVANS, MICHAEL B. ROBINSON AND MICHAEL A. BUSH AND THE REBUTTAL TESTIMONY OF AARON P. ABRAMOVITZ ON BEHALF OF GEORGIA POWER COMPANY IN DOCKET NO. 55378 upon all parties listed below via electronic service or by hand delivery and addressed as follows:

Sallie Tanner  
Executive Secretary  
Georgia Public Service Commission  
244 Washington Street, SW  
Atlanta, GA 30334  
[stanner@psc.ga.gov](mailto:stanner@psc.ga.gov)

Preston Thomas  
Ginny Davis  
Georgia Public Service Commission  
244 Washington Street, SW  
Atlanta, GA 30334  
[pthomas@psc.ga.us](mailto:pthomas@psc.ga.us)  
[gdavis@psc.ga.gov](mailto:gdavis@psc.ga.gov)

Charles B. Jones, III  
Lloyd Avram  
Georgia Association of Manufacturers  
The Hurt Building  
50 Hurt Plaza, Suite 1620  
Atlanta, Georgia 30303  
(404) 688-0555  
[cjones@gamfg.org](mailto:cjones@gamfg.org)  
[lavram@gamfg.org](mailto:lavram@gamfg.org)

Jeffrey C. Pollock  
J. Pollock Incorporated  
14323 South Outer 40 Road, Suite 206N  
Town and Country, Missouri 63017-5734  
(314) 878-5814  
(314) 878-7339 (fax)  
[jcp@jpollockinc.com](mailto:jcp@jpollockinc.com)

Scott F. Dunbar  
Keyes & Fox LLP  
1580 Lincoln Street, Suite 1105  
Denver, CO 80203  
[sdunbar@keyesfox.com](mailto:sdunbar@keyesfox.com)

Alicia Zaloga  
Keyes & Fox LLP  
1155 Kildaire Farm Road, Suite 202-203  
Cary, NC 27511  
[azaloga@keyesfox.com](mailto:azaloga@keyesfox.com)

Bryan Jacob  
Southern Alliance for Clean Energy  
1455 Hampton Hill Drive  
Alpharetta, GA 30022  
[bryan@cleanenergy.org](mailto:bryan@cleanenergy.org)

Jennifer Whitfield  
Robert Sherrier  
Southern Environmental Law Center  
Ten 10<sup>th</sup> Street  
Suite 1050  
Atlanta, GA 30309  
[jwhitfield@selcga.org](mailto:jwhitfield@selcga.org)  
[bsherrier@selcga.org](mailto:bsherrier@selcga.org)

Kimberly ("Kasey") A. Sturm  
Weissman PC  
One Alliance Center, Fourth Floor  
3500 Lenox Road  
Atlanta, Georgia 30326  
[kaseys@weissman.law](mailto:kaseys@weissman.law)

Curt Thompson  
Thompson & Associates Law Firm, PC  
3775 Venture Drive, Suite D100  
Duluth, GA 30096  
[curtbthompson@bellsouth.net](mailto:curtbthompson@bellsouth.net)

Dorothy E. Jaffe  
Sierra Club  
50 F Street, NW, 8<sup>th</sup> Floor  
Washington, D.C. 20001  
[dori.jaffe@sierraclub.org](mailto:dori.jaffe@sierraclub.org)

William Bradley Carver, Sr.  
Hall Booth Smith, P.C.  
191 Peachtree Street, NE  
Suite 2900  
Atlanta, GA 30303  
[bcarver@hallboothsmith.com](mailto:bcarver@hallboothsmith.com)

Liz Coyle  
Georgia Watch  
55 Marietta Street, Suite 903  
Atlanta, GA 30303  
[lcoyle@georgiawatch.org](mailto:lcoyle@georgiawatch.org)

Steven W. Lee  
Spilman Thomas & Battle, PLLC  
1100 Bent Creek Blvd., Suite 101  
Mechanicsburg, PA 17050  
[slee@spilmanlaw.com](mailto:slee@spilmanlaw.com)

Peter J. Andrews  
Metropolitan Atlanta Rapid Transit  
Authority  
2424 Piedmont Road, NE  
Atlanta, GA 30324  
[pandrews@itsmarta.com](mailto:pandrews@itsmarta.com)

Isabella Ariza  
Sierra Club  
50 F Street, NW, 8<sup>th</sup> Floor  
Washington, D.C. 20001  
[isabella.ariza@sierraclub.org](mailto:isabella.ariza@sierraclub.org)

Zachary M. Fabish  
Sierra Club  
50 F Street, NW, 8<sup>th</sup> Floor  
Washington, D.C. 20001  
[zack.fabish@sierraclub.org](mailto:zack.fabish@sierraclub.org)

Simon Mahan  
Southern Renewable Energy Association  
11610 Pleasant Ridge Road  
Suite 103 #176  
Little Rock, AR 72223  
[simon@southernwind.org](mailto:simon@southernwind.org)

Stephanie U. Eaton  
Carrie H. Grundmann  
Spilman Thomas & Battle, PLLC  
110 Oakwood Drive, Suite 500  
Winston-Salem, NC  
[seaton@spilmanlaw.com](mailto:seaton@spilmanlaw.com)  
[cgrundmann@spilmanlaw.com](mailto:cgrundmann@spilmanlaw.com)

John Joseph McNutt  
Regulatory Law Counsel  
U.S. Army Legal Services Agency  
Office of The Judge Advocate General  
Environmental Law Division  
9275 Gunston Road, Suite 4300  
Fort Belvoir, VA 22060-5546  
[john.j.mcnutt.civ@army.mil](mailto:john.j.mcnutt.civ@army.mil)

Chandra Farley  
City of Atlanta, Mayor's Office of  
Sustainability & Resilience  
55 Trinity Avenue, SW, Suite 5000  
Atlanta, GA 30303  
[cfarley@atlantaga.gov](mailto:cfarley@atlantaga.gov)

Alicia Brown  
City of Savannah, Office of Sustainability  
801 E. Gwinnett Street  
Savannah, GA 31401  
[alicia.brown@savannahga.gov](mailto:alicia.brown@savannahga.gov)

Mike Wharton  
Athens-Clarke County Unified  
Government, Sustainability Office  
110 Bray Street  
Athens, GA 30601  
[Mike.Warton@accgov.com](mailto:Mike.Warton@accgov.com)

Peter Hubbard  
Georgia Center for Energy Solutions  
55 Leslie Street, SE  
Atlanta, GA 30317  
[peter@georgia-ces.org](mailto:peter@georgia-ces.org)

Robert B. Baker  
Robert B. Baker, P.C.  
2480 Briarcliff Road, NE, Suite 6  
Atlanta, GA 30329  
[bobby@robertbbaker.com](mailto:bobby@robertbbaker.com)

Mr. Newton M. Galloway  
Ms. Terri M. Lyndall  
Galloway & Lyndall, LLP  
The Lewis Mills House  
406 North Hill Street  
Griffin, GA 30223  
[ngalloway@gallyn-law.com](mailto:ngalloway@gallyn-law.com)  
[tlyndall@gallyn-law.com](mailto:tlyndall@gallyn-law.com)

John R. Seydel  
City of Atlanta, Mayor's Office of  
Sustainability & Resilience  
55 Trinity Avenue  
Atlanta, GA 30303  
[Jrseydel@atlantaga.gov](mailto:Jrseydel@atlantaga.gov)

David Nifong  
City of Decatur, City Manager's Office  
2635 Talley Street  
Decatur, GA 30030  
[david.nifong@decaturga.com](mailto:david.nifong@decaturga.com)

H. Gordon Kenna  
DeKalb County Government  
Department of Public Works  
1300 Commerce Drive  
Decatur, GA 30030  
[hgkenna@dekalbcountyga.gov](mailto:hgkenna@dekalbcountyga.gov)

Jim Clarkson  
Resource Supply Management  
135 Emerald Lake Road  
Columbia, SC 29209  
[jclarkson@rsmenergy.com](mailto:jclarkson@rsmenergy.com)

Donald Moreland  
Georgia Solar Energy Association  
1199 Euclid Avenue  
Atlanta, GA 30307  
[don@solarcrowdsources.com](mailto:don@solarcrowdsources.com)

Kimberly Scott  
Georgia WAND Education Fund, Inc.  
250 Georgia Avenue, SE  
Suite 202  
Atlanta, GA 30312  
[kim@georgiawand.org](mailto:kim@georgiawand.org)




L. Craig Dowdy  
Steven L. Jones  
Taylor English Duma LLP  
1600 Parkwood Circle, Suite 200  
Atlanta, GA 30339  
[cdowdy@taylorenghish.com](mailto:cdowdy@taylorenghish.com)  
[sjones@taylorenghish.com](mailto:sjones@taylorenghish.com)

Tyler Mauldin  
Microsoft Corporation  
200 17<sup>th</sup> Street NW  
Atlanta, GA 30363  
[tylermauldin@microsoft.com](mailto:tylermauldin@microsoft.com)

Whit Cox  
Southern Renewable Energy Association  
337 Druid Oaks Northeast  
Atlanta, GA 30329  
[whit@southernrenewable.org](mailto:whit@southernrenewable.org)

This 18th day of March 2024.

  
Allison W. Pryor  
Attorney for Georgia Power Company

TROUTMAN PEPPER HAMILTON SANDERS LLP  
Bank of America Plaza  
600 Peachtree St., N.E.  
Suite 3000  
Atlanta, Georgia 30308-2216  
(404) 885-3000