STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

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

DIRECT TESTIMONY OF

DEVI GLICK

AND

LUCY METZ

ON BEHALF OF

SIERRA CLUB

FEBRUARY 15, 2024

(PUBLIC VERSION)

Table of Contents

List Figures

List of Tables

1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please list your names and occupations.

A My name is Devi Glick. I am a Senior Principal at Synapse Energy Economics, Inc, (Synapse). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

My name is Lucy Metz. I am an Associate at Synapse. My business address is also 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Ms. Glick, please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in more than a dozen states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electric dispatch models. I have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than 11 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q Ms. Metz, please summarize your work experience and educational background.

A At Synapse, I conduct analysis and write publications on a variety of topics related to integrated resource planning and power plant economics. I regularly support the development of comments and testimony in IRP dockets across the country, including performing analyses of electric power systems using spreadsheet tools and industry-standard models such as EnCompass.

I hold a Bachelor of Science in Engineering Science from Smith College. A copy of my resume is attached as Exhibit LM-1.

Q On whose behalf are you testifying in this case?

A We are testifying on behalf of Sierra Club.

Q Have either of you testified previously before the Georgia Public Service Commission?

A No.

Q What is the purpose of your testimony in this proceeding?

A In this proceeding, we review Georgia Power Company's ("GPC" or "the Company") 2023 Integrated Resource Plan update (2023 IRP Update) and evaluate its proposed resource additions, modeling methodology, and input assumptions. We also evaluate how this update fits into the Company's larger resource planning process and assess the prudency of the Company's resource planning process.

Q How is your testimony structured?

A In Section 2, we summarize our findings and recommendations for the Commission.

In Section 3, we give an overview of GPC's 2023 IRP Update.

In Section 4, we provide a critique of the new resources the Company requests as part of this proceeding.

In Section 5, we discuss GPC's long-term resource planning practices and suggest ways the Company could plan more effectively in the future.

Q What information do you rely upon for your analysis, findings, and observations?

A Our analysis relies primarily on the workpapers, exhibits, and discovery responses of GPC's witnesses. We also rely on other publicly available documents and data, which we cite throughout our testimony.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A Our primary findings are:

1. GPC's projection of rapid industrial and data center load growth in its 2023 IRP Update is driving the need for substantial new near-term capacity relative to its 2022 IRP.
2. The Company's proposed power purchase agreement ("PPA") with Mississippi Power Company ("MPC") begins two years before the

Company needs capacity in the winter of 2025/2026. GPC has not justified procuring the capacity so far in advance of need and passing an estimated [redacted] in unnecessary costs on to Georgia ratepayers.

3. The Company's proposed PPA with Santa Rosa Energy Center begins a year and a half before the Company needs capacity in the winter of 2025/2026. GPC also does not have firm transmission capacity to serve the Santa Rosa Energy Center until May 2026. GPC has not justified procuring the capacity so far in advance of need and passing an estimated [redacted] in unnecessary costs on to Georgia ratepayers.
4. GPC did not adequately consider alternatives to the PPAs with MPC and Santa Rosa.
5. The Company's proposed PPA resources with MPC and Santa Rosa are stopgap solutions that will only help mitigate the Company's capacity shortfall through the winter of 2028/2029. The Company still plans to address its capacity needs beyond that time with resources selected through an RFP and ones already approved in the 2022 IRP.
6. The combustion turbines ("CT") that GPC proposes to construct at Yates would rely heavily on expensive oil during the winter peak months. Oil is expected to be [redacted] times more expensive than gas. These are costs that will be entirely passed on to ratepayers, absent action by the Commission.
7. The Company's 2023 Resource Mix Study deploys over three times as much battery energy storage ("BESS") capacity pre-2030 than the Company proposes in its 2023 IRP Update.
8. It is more economic for GPC to fill part of its firm capacity need with BESS (both paired with solar PV and standalone) and reduce the quantity of, or else eliminate, the gas CTs it installs.
9. If the greenhouse gas regulations proposed under Section 111 of the *Clean Air Act* are finalized, the cost to continue operating the Company's existing fossil plants beyond 2031 and to build new gas plants could be substantially

higher, and the plants' operation limited, relative to what GPC projected in its 2023 Resource Mix Study.

10. GPC's long-term reliance on gas resources will expose customers to fuel price volatility and the associated risks, which the Company did not account for in its IRP. Accelerated deployment of renewables will reduce the Company's reliance on volatile fuel prices and the associated risks to customers.
11. GPC is currently attempting to [redacted] and indicated that it is likely to extend the retirement dates for some of the existing coal and gas assets it owns as part of its next (2025) IRP. The Company's plan to continue reliance on coal and other fossil resources exposes its ratepayers to high costs and risks.
12. GPC's failure to proactively account for upcoming load growth in its 2022 IRP has effectively limited the Company's near-term resource options (for winter 2026) and limited the Commission's ability to effectively oversee GPC's resource planning decisions.

Based on these findings, we offer the following recommendations:

1. The Commission should not approve the PPA with MPC before the winter of 2025/2026. If the PPA is approved, the Commission should require removal from rates of all costs incurred in the months prior to when GPC needs the capacity to serve ratepayers.
2. The Commission should not approve the PPA with Santa Rosa before the winter of 2025/2026. The Commission should also not approve the PPA without firm transmission access. If the PPA is approved, the Commission should require removal from rates of all costs in the months prior to when GPC needs the capacity to serve ratepayers.
3. The Commission should only allow GPC to use the Flex Capacity framework to deploy BESS given that the Company's resource plan found

that it was economic to deploy substantially more BESS than the Company current plans to bring online.

4. The Commission should not approve all three of the Yates CTs and should instead direct GPC to test the market and procure as much battery storage (paired with solar PV and standalone) as it can. GPC should only consider CT capacity to fill the gap that it cannot economically meet with clean energy resources based on on-the-ground market results.
5. GPC should focus its near-term resource planning efforts on obtaining as much new renewable capacity and energy as possible, focusing on BESS and solar PV provided by the market.
6. The Company should fully account for the proposed Section 111 regulations in its modeling, including realistic cost estimates for carbon capture and storage ("CCS") on existing and new proposed fossil resources, and the potential for capacity factor limits and hydrogen co-firing.
7. The Company should adopt more proactive planning processes so it can procure sufficient capacity in the future without suspending request for proposal ("RFP") procedures.
8. The Commission should require that GPC present as part of this 2023 IRP Update any resource additions and retirement decisions that GPC is now considering that deviate from its last IRP.

3. SUMMARY OF COMPANY PROPOSAL

Q Explain the purpose of GPC's 2023 IRP Update.

A In September 2023, GPC released its load forecast for the 2023 IRP Update. GPC's projection of load growth between now and the winter of 2030/2031 is around 17

times greater in the 2023 IRP Update than it was in the 2022 IRP; GPC now projects 6,600 MW of growth by 2030/2031 rather than 400 MW.[1]

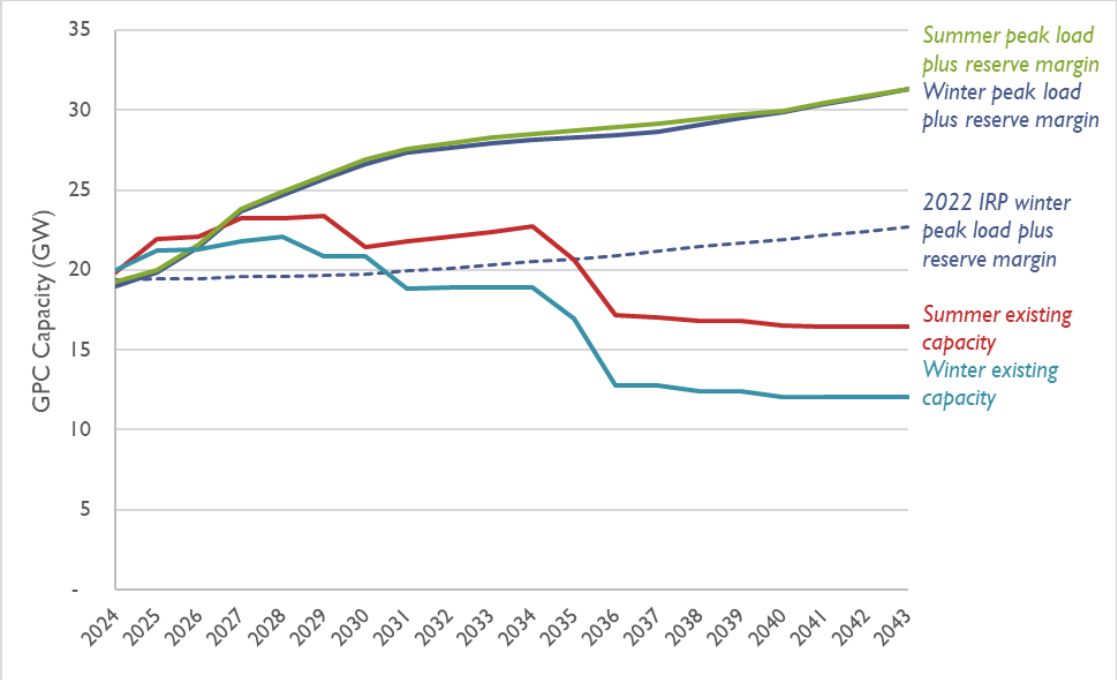
With this update, the Company has also updated its projections of when it will have a capacity shortfall—which is now two years sooner, in the winter of 2025/2026.[2] GPC continues to project that its system will be summer peaking through the end of the study period, but it will have a larger capacity shortfall in the winter. This is driven by its higher winter reserve margin and lower firm capacity ratings of certain resources in the winter (Figure 1). GPC's updated load growth projection has driven its winter capacity need in the 2023 IRP Update (solid purple line) up. Specifically, its projected winter capacity need is now 8.6 GW higher by 2043 than it was in the 2022 IRP projection (dotted purple line).[3]

[1] Georgia Power Company 2023 Integrated Resource Plan Update, October 2023 [known hereafter as "GPC 2023 IRP Update"] at 8.

[2] *Id*. at 10.

[3] *Id*.

Figure 1. Georgia Power Company projected capacity need and existing capacity



Source: "PD GPC and System IRP Summary Data.xlsx", "Figures 4, 5, 6, & 9 – Capacity Needs Data for B22, B23, and 2023 IRP Update.xlsx"

Q Do you have any concerns with GPC's load forecasting methodology?

A Yes. GPC uses a probabilistic model to develop its load forecasts. The forecast that the Company selected as the basis of the 2023 IRP Update is the P95 load level, meaning that "95% of all potential combinations fall at or below this level".[4] This forecast represents an upper limit on load growth rather than the most likely scenario as reflected by the P50 scenario.[5] GPC stated that it relied on this P95 scenario because of the uncertainty surrounding future growth.[6] However, it is not appropriate for GPC to switch to a low-probability load forecast simply because the

[4] GPC 2023 IRP Update, PD Technical Appendix, PD Load and Energy Forecast at 3.
[5] GPC Response to STF-DEA-1-5 (a), attached as Exhibit DG/LM-1.
[6] *Id.*

Company is uncertain about future load growth and its standard P50 forecast does not match with its growth plans and aspirations.

Large new customers such as the new industrial and data center customers anticipated do not come online without lead time and notice to GPC. GPC should have revised its entire forecasting methodology to yield a more accurate forecast in light of the changing nature of new load on its system. Additionally, GPC should evaluate how these new industrial and data center loads are impacting system costs to ensure it is not unfairly shifting costs to existing residential customers.

Q How likely is it that GPC will realize the rapid load growth it currently projects?

A It's highly uncertain, and this is problematic. That is the very reason why GPC opted for the P95 forecast instead of the P50 forecast—because of the uncertainty surrounding future load growth.[7] If load growth does not materialize at the P95 level, GPC may not truly need all the resources for which it is requesting Commission approval. The Company must incorporate this uncertainty into its planning by acquiring more flexible capacity resources (such as BESS) that will not saddle existing ratepayers with extra costs if load growth turns out to be smaller than GPC currently anticipates.

[7] *Id*.

Q What is GPC asking for in its application?

A In the 2023 IRP Update, GPC proposes a set of resources that would close the capacity gap through the winter of 2027/2028, but create a capacity surplus in the near term (Table 1). The Company's proposed resource additions, which it would obtain through exceptions to the Commission's RFP process, include:

- PPA with MPC for 750 MW of capacity and energy[8]
- PPA with the Santa Rosa Energy Center for 230 MW of capacity and energy[9]
- 1,400 MW from three simple-cycle CTs at Plant Yates that would be dual-fueled with oil and gas, due to a lack of firm gas transportation available at the site[10]
- Up to one gigawatt of BESS, including 178 MW of 4-hour lithium-ion batteries at the Robins and Moody Air Force Base and 200 MW of BESS co-located with 200 MW of new solar[11]

The Company also seeks approval of the following as part of the 2023 IRP Update:

- Two new distributed energy resource programs, one new tariff-based demand response program, and an amended certificate for one existing demand-side management program[12]
- A Flex Capacity framework[13]
- Expansion of the transmission system to accommodate the resources above[14]

Table 1. GPC winter capacity deficit and (surplus) before and after proposed resource additions

	2023/24	2024/25	2025/26	2027/28	2028/29	2029/30

[8] GPC 2023 IRP Update at 17.
[9] *Id*. at 17-18.
[10] *Id*. at 21-22; GPC Response to PD STF-JKA-2-22, attached as Exhibit DG/LM-2.
[11] GPC 2023 IRP Update at 20.
[12] *Id*. at 22.
[13] *Id*. at 23-24.
[14] *Id*. at 28.

Initial Winter Capacity Need	(964)	(1,352)	175	1,875	2,601	4,807
Proposed New Resources	239	469	980	1,877	2,500	1,989
Mississippi Power PPA	750	750	750	750	750	-
Santa Rosa PPA	-	230	230	230	230	-
Yates CT	-	-	-	357	600	1,070
Battery storage	-	-	-	540	920	920
Sales to regional provider	(511)	(511)	-	-	-	-
Final Winter Capacity Need	(1,203)	(1,821)	(805)	(1)	102	2,818

Source: GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B.xlsx. We assume that the Santa Rosa PPA will begin in May 2024 based on GPC's response to PD STF-JKA-6-7 (d).

4. CRITIQUE OF IRP UPDATE PROPOSED RESOURCES

i. The PPA with Mississippi Power Company saddles GPC ratepayers with excess capacity over the next two years, and GPC signed it without adequate consideration of alternatives

Q Provide a summary of the MPC PPA.

A In October 2023, GPC executed a PPA with MPC for 750 MW of capacity and energy for the term January 1, 2024 – December 31, 2028.[15] The capacity and energy provided through the PPA is not contractually tied to any one generating asset. However, it appears that the PPA is being used to justify MPC's decision not to close its coal unit at Plant Daniel and gas steam unit Watson 4 at year end 2027 and year end 2023, respectively, as planned. [redacted]

[15] *Id*. at 17.

[redacted]

Q What is GPC asking for with regards to the MPC PPA in this docket?

A GPC is asking for: (1) a certification of public convenience and necessity (CPCN) for the PPA between GPC and MPC; (2) regulatory asset treatment to defer the energy and capacity payments it is making to MPC, net of the revenues it makes from reselling any energy and capacity for the period January 1, 2024 – December 31, 2025.[20]

Q Did GPC adequately consider alternatives to the PPA with MPC?

A No. GPC asserted that it opted for this PPA instead of going to the market because "There is not enough time for an RFP to be conducted, resources to be constructed

[16] GPC Response to TS STF-PIA-7-15, TS Attachments A-P, attached as Exhibit DG/LM-3.

[17] GPC Response to TS STF-PIA-7-15, Attachment O, *see* Exhibit DG/LM-3.

[18] GPC Response to TS STF-JKA-2-19, Attachment B, attached as Exhibit DG/LM-4; also provided in GPC Response to TS STF-JKA-4-19, Attachment.

[19] GPC 2023 IRP Update, TS Technical Appendix, TS Power Purchase Agreement Between Georgia Power Company and Mississippi Power Company Executed [known hereafter as "TS Executed PPA between GPC and MPC"].

[20] GPC 2023 IRP Update at 17.

following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027."[21]

But the Company has not demonstrated that there were no alternative options available to meet its 2025/2026 capacity needs. The MPC PPA was identified in July 2023 as a potential resource option[22] and by October 2023, less than four months later, the PPA was signed. MPC rushed the decision without adequately considering alternatives.

Q What actions did GPC take to evaluate alternative resource options to meet its 2025/2026 capacity need?

A GPC issued a Request for Information ("RFI") on September 26, 2023.[23] But the timing is such that GPC could not have seriously considered the RFI results prior to executing the contract.

- July 27, 2023: GPC identified a supposed capacity need as early as July and [redacted].[24]
- [redacted]

[21] GPC 2023 IRP Update, 2023 IRP Update Supplemental Filing PD, Request for Information Summary [known hereafter as "Request for Information Summary"], Section 2.3. December 4, 2023.

[22] GPC Response to PD STF-JKA-6-5 (c), attached as Exhibit DG/LM-5.

[23] GPC Response to PD STF-JKA 4-10, attached as Exhibit DG/LM-6; *also see*, Request for Information Summary.

[24] GPC Response to PD STF-JKA-6-5 (c), attached as Exhibit DG/LM-5; GPC Response to TS STF-PIA-7-15, Attachment O, *see* Exhibit DG/LM-3.

[25] GPC Response to TS STF-PIA-7-15, Attachment A, *see* Exhibit DG/LM-3.

- September 26, 2023: The RFI was issued by GPC. By this time, [redacted]
- October 11, 2023: GPC signed the PPA contract with MPC.[28]
- October 24, 2023: RFI closing date, nearly two weeks *after* GPC signed the PPA with MPC.[29]

Q Are there any other concerns with GPC's consideration of alternatives?

A Yes. GPC issued an RFI and not a Request for Proposals ("RFP"). An RFI is distinct from an RFP in that no bids or pricing is required to be provided by all respondents. This is something GPC knew. The Company did get multiple bids under the RFI but nonetheless GPC didn't seriously consider any of the results. Specifically, GPC said:

> The Company did not perform a detailed analysis on the potential projects identified in Table 2-3-2 in the RFI summary showing that 100 MW of capacity could be acquired for 2025, 1,100 for 2026 and 1,495 in 2027 because there was not adequate time to administer and conduct an RFP that provides for all bids to be properly evaluated, conduct transmission studies, and ultimately construct new assets or interconnection facilities to meet the capacity needs being addressed in the 2023 IRP Update. In addition, if provided, pricing information was optional and non-binding for participants responding to the RFI and

[26] GPC Response to TS STF-PIA 7-15, Attachment O, *see* Exhibit DG/LM-3.
[27] GPC Response to TS STF-PIA 7-15, Attachment M, *see* Exhibit DG/LM-3.
[28] 2023 IRP Update at 17.
[29] Request for Information Summary.

interconnection plans are not known, any of which could significantly impact a potential project's availability.[30]

GPC knew that an RFI didn't require respondents to provide information sufficient to assess a project's feasibility, yet it still issued an RFI instead of a full RFP. In addition, it waited until the end of September to do so and then claimed it didn't have time to consider alternatives. If GPC was serious about securing capacity from the market it would have issued a full RFP instead of just the RFI and it would have done so earlier in the summer. Instead, it appears that the RFI was issued after the fact to justify a decision the Company had already made. The Company performed no robust analysis on the RFI results and never appeared to seriously consider any resources from the RFI.

Q Where is the power coming from that MPC is providing under the PPA?

A The power is coming from excess capacity that MPC was ordered to retire by the Mississippi Public Service Commission (the "Mississippi Commission"). Specifically, back in 2020, the Mississippi Commission ordered MPC to include in its next IRP filing "the schedule of early or anticipated retirement of approximately 950 megawatts of generating capacity by year-end 2027 or show cause with detailed evidence why the continued operation of some or all of MPC's existing fossil steam generation is in the best of interest of customers and MPC."[31] In its

[30] GPC Response to STF-JKA 4-10, attached as Exhibit DG/LM-6.

[31] Mississippi Public Service Commission. 2020. Final Order in Docket No. 2018-AD-145. Pages 5-6.

2021 IRP, MPC submitted a plan to retire 976 MW of coal and gas steam capacity.[32] This included a retirement date of year end 2023 for Watson Unit 4 (gas steam), and year end 2027 for MPC's share of Plant Daniel (coal steam).[33]

Sometime between 2021 and now MPC decided that it would attempt to re-market the power to GPC instead of retiring the capacity.

Q Is it guaranteed that the power will be available starting in winter 2025/2026?

A No. GPC intends for this PPA to maintain several MPC plants within the Southern Company pool. And while MPC and its parent company Southern Company may want to remarket the capacity, the Mississippi Commission may not view the PPA as a sufficient justification for keeping additional capacity online past the end of 2027. There is no obvious benefit to Mississippi ratepayers, whose utility maintains liability for excess capacity not needed to serve its native load.[34] The Mississippi Commission does not need to review the PPA before it is executed,[35] leaving open the possibility that it would find the PPA imprudent at a later date. This could put the availability of the PPA at risk towards the end of the contract period, just when GPC's capacity need will be greatest.

[32] Mississippi Power Company. 2021. *Mississippi Power 2021 IRP Filing*. Mississippi Public Service Commission Docket No. 2019-UA-231. Page 4.

[33] *Id*.

[34] Review and Assessment of Mississippi Power Company's Reserve Margin Plan, Report to the Mississippi Public Utilities Staff. Prepared by Bates White, LLC. September 17, 2020.

[35] GPC Response to PD STF-JKA-2-19 (b), attached as Exhibit DG/LM-4.

Q Are there risks to GPC customers of signing a PPA for power that relies on an aging coal plant?

A Yes. As discussed in Section 5 below, there are significant risks from environmental regulations, price volatility, and contraction in the coal market.

Q Is the PPA with MPC well-matched to GPC's capacity need?

A No. Even under GPC's revised and dramatically increased forecast, GPC doesn't need capacity and energy until winter 2025/2026. That means that it is paying for excess capacity and energy for almost two years, or else taking on the risk of reselling it.

Q Why did GPC take on the capacity two years before it needed capacity?

A As stated above, GPC claims that it took the excess capacity for the next two years because "[h]ad Georgia Power not executed the PPA for the full five years, the proposed resource very likely would not have been available for the last three years when the Company has a capacity need."[36] But evidence provided in discovery does not support this claim:

[redacted]

[36] GPC Response to PD STF-JKA-2-20 (a), attached as Exhibit DG/LM-7.

[37] GPC Response to TS STF-PIA-7-15, Attachment A, *see* Exhibit DG/LM-3.

[38] GPC Response to TS STF-JKA 2-19, Attachment B, attached as Exhibit DG/LM-4; also provided in GPC Response to TS STF-JKA 4-19, Attachment.

[39] TS Executed PPA between GPC and MPC.

[40] GPC Response to TS STF-JKA 2-19, Attachment B, attached as Exhibit DG/LM-4; also provided in GPC Response to TS STF-JKA 4-19, Attachment.

[redacted]

[redacted]

Q What costs is GPC asking to pass on to its ratepayers associated with the MPC PPA prior to winter 2025/2026?

A The PPA will cost GPC [redacted] ($2024 NPV) in capacity payments[41] for the years 2024–2025.[42] GPC asserts that it has already contracted to sell 500 MW for the term January 1, 2024–September 30, 2025.[43] From that sale, GPC will recover around [redacted] in 2024–2025.[44] That leaves GPC ratepayers with [redacted] for capacity that it doesn't need and isn't using over the next two years.[45]

GPC stated in discovery that it is negotiating with the buyer of the first 500 MW to sell the remaining 250 MW.[46] It is unclear if and when this will happen given that we are already a month and a half into 2024 and GPC is already paying [redacted] a month for the 250 MW of capacity that it doesn't need while receiving no value in return.[47]

[41] This includes capacity costs and a cost labeled "Additional Sum."

[42] Calculated based on GPC 2023 IRP Update, TS Updated Economic Analysis of Capacity Resources spreadsheet [known hereafter as "TS Updated Economic Analysis of Capacity Resources"]; TS Executed PPA between GPC and MPC.

[43] GPC 2023 IRP Update at 17.

[44] Calculated based on TS Updated Economic Analysis of Capacity Resources; GPC Response to TS STF-JKA-4-19, Attachment.

[45] *Id*.

[46] GPC Response to STF-JKA-4-19 (c), attached as Exhibit DG/LM-8.

[47] Calculated based on TS Executed PPA between GPC and MPC.

Q Is GPC aware that there is a risk of disallowance from the Georgia Public Service Commission with this PPA arrangement?

[redacted]

Q What do you recommend regarding the PPA with MPC?

A I recommend that the Commission disallow inclusion in retail rates of the PPA costs prior to when the capacity is needed in winter 2025/2026. GPC has not demonstrated that it made sufficient efforts to procure capacity from other resources that aligned more closely with the timing of its capacity needs. While the Company is making efforts to remarket the excess capacity, there is no guarantee it will be successful, therefore the costs and risk of that should not be borne by GPC ratepayers.

[48] GPC TS Response to STF-PIA-7-15, Attachment P, *see* Exhibit DG/LM-3.

[49] GPC TS Response to STF-PIA-7-15, Attachment H, *see* Exhibit DG/LM-3.

ii. The PPA with Santa Rosa Energy Center saddles GPC ratepayers with excess capacity over the next year and a half, and it does not guarantee firm transmission access for the entire contract term

Q Provide a summary of the Santa Rosa PPA.

A GPC is requesting approval to sign a PPA with the Santa Rosa Energy Center for 230 MW of capacity and energy. This PPA will provide capacity from a CC plant located in Pace, Florida. The PPA has been executed but GPC has not begun to pay for capacity yet. The PPA is scheduled to begin one month after Commission approval (GPC estimates that is May 1, 2024)[50] and continue through the end of December 2028.[51]

Q What is GPC asking for specifically in this case?

A GPC is asking for: (1) a CPCN for the PPA between GPC and Santa Rosa; (2) regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, net of revenue from resales.[52]

Q Is the PPA with Santa Rosa Energy Center well-matched to GPC's capacity need?

A No. Once again, GPC doesn't need capacity and energy until winter 2025/2026. That means that if the Commission approves the PPA prior to January 1, 2026, GPC

[50] GPC Response to PD STF-JKA-6-7(d), attached as Exhibit DG/LM-9.
[51] GPC 2023 IRP Update at 17.
[52] *Id*. at 17-18.

ratepayers will be paying for excess capacity and energy or else taking on the risk of reselling it.

In defense of this PPA, GPC repeats its assertion that it opted for this PPA instead of going to the market because "There is not enough time for an RFP to be conducted, resources to be constructed following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027."[53] GPC goes on to claim that the Santa Rosa Energy Center was a known, existing generation asset that was identified in July 2023. Since the project could meet resource needs without any new transmission projects, the Company negotiated an agreement before October 2023.[54]

But, as discussed above, the Company failed to demonstrate that there were no alternative options to purchasing excess and unnecessary capacity.

Q What efforts did GPC take to evaluate alternative resource options to meet its 2025/2026 capacity need?

A As discussed above, GPC made no real efforts to procure capacity from the market. I have the same concerns with GPC's procurement of this PPA as I did with the MPC PPA—mainly the timeline and the use of an RFI rather than an RFP in a veiled attempt to justify the decisions that the Company had already made.

[53] GPC Response to PD STF-JKA-6-5, attached as Exhibit DG/LM-5.
[54] *Id*.

Q What costs is GPC asking to pass on to its ratepayers associated with Santa Rosa PPA prior to winter 2025/2026?

A Assuming the PPA started May 1, 2024, it would cost GPC [redacted] ($2024 NPV) in capacity payments[55] for the years 2024–2025.[56] Given that the PPA doesn't start until it is approved by the Commission, customers would save approximately [redacted] in capacity costs for each month the Company is not under contract to purchase the Santa Rosa capacity.[57]

GPC asserts that, once approved, it will include the Santa Rosa capacity available prior to winter 2025/2026 in an RFP.[58] Further, GPC states that it expects to remarket the capacity to a regional electrical service provider at a [redacted].[59] However, GPC did not disclose which potential parties may be interested in the capacity. GPC's ability to re-sell the capacity is not certain, and if the PPA is approved and the Company cannot remarket the capacity, GPC ratepayers will be on the hook for the full cost.

Additionally, GPC revealed in a supplemental discovery response it doesn't have firm transmission capacity for the PPA from 2024–May 2026.[60] This includes the entire time the Company would attempt to re-market the capacity, as well as the

[55] This includes capacity costs, accounting lease, and a cost labeled "Additional Sum."

[56] TS Updated Economic Analysis of Capacity Resources; GPC 2023 IRP Update, TS Technical Appendix, TS Power Purchase Agreement Between Georgia Power Company and Santa Rosa Energy Center LLC Executed [known hereafter as "TS Executed PPA between GPC and Santa Rosa"].

[57] Calculated based on TS Updated Economic Analysis of Capacity Resources; TS Executed PPA between GPC and Santa Rosa.

[58] GPC 2023 IRP Update at 17; GPC Response to STF-JKA-4-19 (e), attached as Exhibit DG/LM-8.

[59] GPC Response to TS STF-PIA-10-3, attached as Exhibit DG/LM-10.

[60] GPC Supplemental Response to STF-JKA-2-2 (f), attached as Exhibit DG/LM-11.

first half of 2026 when the Company needs the capacity. This is concerning because it means that the PPA doesn't actually provide firm capacity for the first half of 2026 when GPC needs it. It also renders the capacity less valuable on re-sale and will impact the price that GPC could get for the power if it attempts to re-market it. GPC stated that it is pursuing short-term firm transmission for the resources during this period[61] but it's unclear whether this will happen and how much that will cost.

Q What do you recommend with regard to the PPA with Santa Rosa?

A I recommend that the Commission disallow inclusion in retail rates of the PPA costs prior to when the capacity is needed in winter 2025/2026. The Commission should also not approve the PPA until the firm transmission capacity issue is resolved. As discussed above, GPC did not adequately consider alternatives, or otherwise make efforts to procure capacity resources that aligned more closely with the timing of its capacity needs. While the Company claims it will make efforts to remarket the excess capacity, it provides no specifics. And regardless there is no reason why the costs and risk of that should be borne by GPC ratepayers. At best, the arrangement will be net neutral for ratepayers. At worst, it will cost them [redacted] over the next two years in exchange for zero value. This arrangement provides no upside benefit to ratepayers.

[61] *Id*.

iii. The Yates combustion turbines will be costly to build and operate, and are likely to cost more than an equivalent amount of 4-hour BESS

Q Summarize your concerns with GPC's proposal to construct three combustion turbines at Plant Yates.

A The three dual-fueled CTs at Yates would impose unnecessary costs and pollution burdens on Georgia residents. First, [redacted].[62] Second, because no firm gas capacity is available to the plants, the CTs would rely on oil—an expensive and highly polluting fuel—during peak periods.[63] Overall, we find it would be more economic to replace the firm capacity of one or more of the CTs with 4-hour BESS, which could be charged at low cost with energy from solar PV as well as the grid.

[redacted] **Q** [redacted]

[redacted]

[redacted] **A** [redacted]

[redacted] [redacted] After the Company finalized an

[62] GPC Response to TS STF-DEA-3-6, Attachment G, attached as Exhibit DG/LM-12; GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G, attached as Exhibit DG/LM-13.

[63] GPC Response to PD STF-JKA-2-22, attached as Exhibit DG/LM-2.

[64] Calculated based on GPC Response to STF-DEA-3-6, Attachment G, attached as Exhibit DG/LM-12; GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G, attached as Exhibit DG/LM-13.

[65] GPC Response to TS STF-DEA-3-6, Attachment G, attached as Exhibit DG/LM-12.

Engineering, Procurement, and Construction (EPC) agreement for the units in January 2024,[66] [redacted] [67] GPC indicated in discovery that the lateral was being build adjacent to the existing pipeline lateral to Plant Yates from Transco,[68] [redacted]

Q Explain your concern with GPC's plan to build new peaking gas plants without a firm gas supply.

A Gas pipeline capacity in GPC's service area is increasingly constrained.[70] GPC did not procure firm transportation capacity for the Yates CTs and reports that the units are unlikely to have a reliable supply of gas during peak conditions as a result.[71] Instead, the CTs will be dual-fueled and will burn oil whenever sufficient gas is unavailable. The turbines will have a combined capacity of 1,400 MW when operating on gas and 1,000 to 1,100 MW when operating on oil.[72] Notably, the Company failed to provide estimates for the amount of oil and gas each unit will

[66] GPC 2023 IRP Update, PD Georgia Power Company Application for Certification of Plant Yates 8–10 at 19.

[67] GPC Response to TS STF-DEA-3-6, Attachment G, attached as Exhibit DG/LM-12; GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G, attached as Exhibit DG/LM-13.

[68] GPC Response to STF-JKA 2-22 (d), attached as Exhibit DG/LM-2.

[69] Calculated from GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G, attached as Exhibit DG/LM-13.

[70] GPC Response to STF-JKA-2-14 (e), attached as Exhibit DG/LM-14.

[71] GPC Response to PD STF-JKA-2-22, attached as Exhibit DG/LM-2.

[72] GPC 2023 IRP Update at 21.

burn in a given year. It modeled the units as using oil during winter months (December through February) and gas in other months,[73] but elsewhere stated that the units might also rely on oil during summer peak periods.[74]

Q How will oil-burning impact the cost to operate the CTs?

A Oil is much more expensive per unit energy than gas.[75,76] [redacted] shows GPC's projections of dispatch costs for the Yates CTs operating on gas and oil. The cost per megawatt-hour using oil is [redacted] times greater than gas throughout the study period. While the units are technically capable of providing firm capacity during winter months when GPC has the greatest capacity need, it will be extremely expensive to run them during these times based on high fuel costs. These are fuel costs that will be passed directly through to customers, absent Commission disallowance of fuel costs.

[redacted]

Source: TS Attachment B – Plant Yates Units 8 – 10 Applicable Variable Cost and Operations Data.

[73] GPC Response to STF-JKA-3-10, attached as Exhibit DG/LM-15.

[74] GPC Response to STF-JKA-2-22 (d), attached as Exhibit DG/LM-2.

[75] U.S. Energy Information Administration. 2024. "Henry Hub Natural Gas Spot Price." Available at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

[76] U.S. Energy Information Administration. 2024. "Petroleum & Other Liquids Spot Prices." Available at: https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

Q How will the performance of the CT units be impacted by burning oil relative to burning gas?

A Emissions rates for both toxic air pollutants and greenhouse gases are higher for a CT when operating on oil than when operating on gas, as shown in Table 3 below. The Company estimates that the emissions rates of nitrogen oxides ("NO_X") will be more than twice as high when the Yates CTs operate on oil compared to gas. Similarly, the emissions rates for particulates and air toxics will be over four times higher on oil, and the carbon dioxide (CO_2) emissions rate will be 36 percent higher. Burning oil at Yates will therefore not only be more costly; it will also negatively impact public health and will make the units vulnerable to future environmental regulation relative to operation on gas.

Table 3. Emissions rates for Yates combustion turbines operating on gas and oil

Pollutant	Unit	Gas	Oil	Percent difference
NO_x	lb/MMBtu	0.0099	0.022	122%
Particulates and air toxics	lb/MMBtu	0.0034	0.015	341%
CO_2	lb/MMBtu	119	162	36%

Source: PD Georgia Power Company Application for Certification of Plant Yates Units 8-10, page 17.

Q What types of resources should the Company procure to meet its firm capacity needs?

A BESS would provide the same dispatchable firm capacity value as a gas CT, and 4-hour BESS are readily available and cost-competitive today. In the 2023 IRP Update main document, GPC suggests that CTs provide unique benefits that short-

duration storage would not, but this claim is unsupported.[77] And GPC itself is seeking to develop, operate, and own up to 1,000 MW of BESS, including 378 MW of 4-hour BESS across two different projects as early as the winter of 2026/2027.[78]

GPC's system has ample capability to add 4-hour storage before its capacity contribution will begin to decline (based on GPC's own effective load carrying capability (ELCC) assumptions). This is because GPC specifically, and Southern Company as a whole, currently has very little battery storage installed on the system. GPC does not yet own any operational BESS, although it does have PPAs for 409 MW nameplate capacity of paired solar and storage (as of the winter of 2023/2024).[79] According to the IRP Update, the Company plans to begin bringing Company-owned BESS online as soon as 2024.[80] Mississippi Power Company owns one demonstration solar-storage project,[81] and Alabama Power Company does not report any BESS currently on its system.[82] As shown in Table 4, Southern Company assigns a 100 percent ELCC to the first 3,000 MW of BESS installed on its system.[83]

[77] GPC 2023 IRP Update at 21.

[78] *Id*. at 19.

[79] Calculated based on GPC Response to STF-JKA-2-2, Attachment C.xlsx, attached as Exhibit DG/LM-16.

[80] GPC Response to STF-JKA-4-14 (a), attached as Exhibit DG/LM-17.

[81] Mississippi Power Company. 2021. *Mississippi Power 2021 IRP Filing*. Mississippi Public Service Commission Docket No. 2019-UA-231. Page 4.

[82] Alabama Power Company. 2022. *Alabama Power 2022 Integrated Resource Plan Summary Report.* Available at: https://www.alabamapower.com/content/dam/alabama-power/pdfs-docs/company/compliance---regulation/IRP.pdf.

[83] GPC Response to STF-JKA-2-11, Attachment F, attached as Exhibit DG/LM-18; the ELCC study appears to be for the entire Southern Company system and not just Georgia Power's system.

It is true that adding batteries for firm capacity will require GPC to develop new capabilities for managing the charge and discharge of BESS, for example to make sure that the batteries charge during time periods with high energy availability to ensure that they are available during peak periods. But this is something utilities with installed BESS system around the country are already doing. There is over 15 GW of BESS installed in the United States right now, and of that 1.8 GW is owned by utilities.[84] And much more is planned to come online in the new few years. GPC will have to learn in short order to maintain an economic electricity system. This process will be smoother if the Company moves aggressively to integrate BESS now rather than delaying until it has a large capacity need.

Table 4. GPC / Southern Company's estimate of incremental ELCC for 4-hour battery storage installed on its system

Total Battery Capacity (MW)	Incremental ELCC: Winter	Incremental ELCC: Summer
1,000	100%	92%
2,000	100%	100%
3,000	98%	100%
4,000	92%	100%
5,000	84%	95%
6,000	75%	85%

Source: STF-JKA-2-11 Attachment F.

[redacted]

[84] U.S. Energy Information Administration, form 860 monthly, December 2023.

[redacted] GPC expects the three Yates units to be "substantially completed" 32, 37, and 40 months after finalization of the EPC agreement (equivalent to December 2026, May 2027, and August 2027).[87] [redacted] especially given that the Yates CTs will be transmission-constrained until May 2028 and will provide only 600 MW of firm capacity until transmission upgrades are complete.[88] [redacted]

Q Has GPC provided [redacted] information suggesting that it could procure BESS on a similar timeline to constructing CTs at Yates?

A Yes. In its January supplemental filing, GPC implicitly confirmed that it is capable of procuring BESS on a more rapid timeline than building the Yates CTs. Between the initial and supplemental IRP Update filings, the in-service date of Yates Unit 9 was delayed from December 2026 to May 2027, and Yates Unit 10 was delayed

[85] GPC Response to TS STF-PIA-10-1, attached as Exhibit DG/LM-19.

[86] GPC plans to include SCRs at the Yates CTs according to GPC 2023 IRP Update, PD Georgia Power Company Application for Certification of Plant Yates Units 8–10.

[87] GPC Supplemental Response to STF-JKA-2-22 (f), attached as Exhibit DG/LM-11.

[88] GPC Response to PD STF-JKA-1-4 (e), attached as Exhibit DG/LM-20.

from April 2027 to August 2027.[89] To make up for the capacity shortfall that was supposed to be filled by Yates 9 during the winter of 2026/2027, GPC shifted forward 180 MW of battery storage.[90] This confirms that GPC itself thinks that it can procure battery storage in time for the winter of 2026/2027, and therefore should be more ambitious about constructing storage and solar instead of building all three gas CTs.

Q Do the CTs offer the lowest cost option for GPC to procure firm capacity?

A No. We compared the 15-year net present value of the capacity cost for a single CT, Yates Unit 8, with a comparable quantity of 4-hour battery storage. We found that the BESS costs [redacted] less than the CT[91] by comparing just the fixed and capital cost (including financing, taxes and tax credits, insurance, etc.) of the two resources. Because CTs are a low utilization capacity resource, we did not consider variable costs including fuel as well as energy revenues. If we had, the cost difference likely would have come out even more in favor of the BESS system given the high-cost GPC projects it will have to pay for oil to operate the CTs and

[89] PD Technical Information Supporting the Proposal to Develop up to 1,400 MW of CTs, October 2023 (original filing); Georgia Power Company's Application for Certification of Plant Yates Units 8-10, Supplemental filing, January 31, 2024 (document labeled DKT 55378 Yates 8-10 App for Certification).

[90] GPC Supplemental Response to STF-JKA-2-2 (f), Supplemental Attachment B, attached as Exhibit DG/LM-21; GPC Response to STF-JKA-2-2 (f), Attachment C, attached as Exhibit DG/LM-16.

[91] Calculated from GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G.xlsx, attached as Exhibit DG/LM-13; GPC 2023 IRP Update, TS Updated Economic Analysis, TS Updated Economic Analysis of Capacity Resources.xlsx; GPC 2023 IRP Update, TS Technical Appendix, TS Southern Company 2023 Integrated Resource Plan Update Resource Mix Study at 5 and 14; GPC 2023 IRP Update, TS Technical Appendix, TS Technical Information Supporting the Proposal to Develop up to 1400 MW from Three Simple Cycle Combustion Turbines at Plant Yates.

the ability for BESS to charge from zero marginal cost solar PV and low-priced market power.

Q Does the Company need the CTs at Yates to maintain 70 percent ownership of its supply-side resources?

A No. The Company's justification that it needs the Yates CTs to comply with a "long-standing Commission policy [that] requires Georgia Power to own at least 70 percent of its supply-side resources"[92] is specious. First, our understanding is that this "long-standing policy" is not a binding requirement and that there is no requirement for GPC to own 70 percent of its supply-side resources. The Company may desire to directly control most of its assets, but Commission oversight should apply equally to assets paid for by ratepayers, regardless of whether they are owned by the Company or contracted under a PPA. Second, GPC can self-build BESS, and doing so would help the Company maintain its 70 percent self-build goal. Finally, policies can and should be updated as the grid changes and markets evolve. The Commission order referencing 70 percent ownership "policy" dates to 2001, when power sector regulatory concerns were different from today.[93]

Q Are ownership requirements like this beneficial to ratepayers?

A No. Competition in electricity supply is good for ratepayers. The only party that benefits from a utility ownership policy is GPC itself. GPC should be securing

[92] GPC 2023 IRP Update at 18.

[93] Georgia Public Service Commission. 2001. Final Order in Docket Nos. 12499-U, 13305-U and 13306-U. Page 21.

resources based on what is available in the market at the lowest cost, not based on which resources can provide the biggest rate of return for its shareholders. If the Company knows it is allowed to self-build a resource without competing in the market, there is no incentive for GPC to be cost competitive—especially if the Company earns a rate of return on anything it builds. It is unlikely the Commission intended to arbitrarily limit or eliminate competition in a way that results in higher costs for ratepayers.

Additionally, a rule that limits third-party ownership would deter renewable developers from coming to the state, impede state economic growth, and cause GPC to incur unnecessary costs for new resources, while providing no additional reliability benefits. As mentioned above, third-party ownership does not limit the Commission's ability to provide oversight. But third-party ownership does decrease the size of the utility's rate base. Because PPA payments are collected as pass-through costs without a rate of return, they are sometimes less unattractive to utilities focused on shareholder returns.

Q What does evidence from other states suggest about the likely cost-effectiveness of Company-owned resources compared to PPAs?

A PPAs are lower cost than utility-owned resources in much of the country right now. If the Commission were to enforce a 70 percent utility ownership requirement, GPC would over-pay for new resources. Asking the utility to compete with the market does not inhibit the utility's ability to self-build, it just requires the utility to

demonstrate that doing so is in the best interest of ratepayers relative to alternatives from developers.

iv. GPC should only use the Flex Capacity Framework for resources it has already found to be economic, such as BESS

Q What is the Flex Capacity framework that GPC is proposing?

A GPC is requesting approval of a framework that it claims would allow it to more quickly respond to additional increases in its load forecast and help the Company meet new capacity needs prior to the winter of 2028/2029.[94] Specifically, the proposal requests that the Commission:

1. Provide authorization to undertake preliminary development activities in connection with the development, operation, and ownership of new capacity resources.[95]
2. Provide approval for GPC to defer collection of costs for preliminary development activities related to new sources of capacity, that would normally be expensed, to instead be placed in a regulatory asset with the amortization period to be determined in the Company's next base rate case.[96]

[94] GPC 2023 IRP Update at 23-24.
[95] *Id*. at 23.
[96] *Id*. at 24.

Q What do you recommend with regards to the Flex Capacity framework?

A We recommend that GPC use the framework to support the installation of BESS resources to meet its near-term capacity needs. The Company's Resource Mix Study already found that it was economic for GPC to procure a large quantity of BESS capacity over the next 5–10 years.[97] This is substantially more than the 1,000 MW of BESS GPC proposed in its IRP Update.[98] Therefore, we find it would be reasonable for GPC to use this framework to have its build-plans most closely match with the results of its resource planning analysis.

Q Should the Commission allow GPC free reign to use the Flex Capacity framework for all resource types?

A No. Although the Resource Mix Study also found additional gas resources to be cost-effective,[99] we are concerned that the Company's modeling did not adequately account for the costs and risks associated with continued reliance on fossil capacity. Further, the Company is already proposing a substantial build-out of gas in the near term.

[97] GPC Response to STF-JKA-2-2, Attachment C.xlsx, attached as Exhibit DG/LM-16; GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B.xlsx, attached as Exhibit DG/LM-21.

[98] GPC 2023 IRP Update at 23.

[99] GPC Response to STF-JKA-2-2, Attachment C.xlsx, attached as Exhibit DG/LM-16; GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B.xlsx, attached as Exhibit DG/LM-21.

v. GPC should procure more BESS and renewables to align with its findings around the economics of new resource options

Q What does GPC's 2023 IRP Update show about its near-term plans for adding BESS to its system?

A GPC's 2023 IRP Update includes plans to add up to 1 GW of new BESS,[100] as shown in Table 5 below. This is in contrast with GPC's own modeling in its 2023 Resource Mix Study, which finds that it would be economic for GPC to procure over three times as much (3.4 GW) of BESS by 2030 in the moderate fuel price scenario and between 3.1 and 4.4 GW in the other scenarios.[101]

Table 5. Cumulative battery storage additions in megawatts (nameplate capacity)

	2027	2028	2029	2030
IRP Update	**578**	**1,000**	**1,000**	**1,000**
Robins & Moody BESS	178	178	178	178
BESS Co-located Solar	200	200	200	200
Other BESS	200	622	622	622
Resource Mix Study (MG0 scenario)	**900**	**1,680**	**3,380**	**3,380**
2022 IRP ESS RFP	-	-	500	500
4-hr Battery Tier 1	900	1,680	2,460	2,460
4-hr Battery Tier 2	-	-	420	420

Source: Calculated from GPC Response to STF-JKA-2-2, Attachment C.xlsx; GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B.xlsx; GPC 2023 IRP Update Supplemental Filing Errata 12-7-23 PD, PD Capacity Expansion Plans Supplemental - Errata.xlsx; GPC 2023 IRP Update at 20.
Note: Table does not include previously approved projects such as Mossy Branch and McGrau Ford which GPC included in both the 2023 IRP Update and Resource Mix Study (See GPC Response to STF-JKA-4-14).

[100] 2023 IRP Update at 20.

[101] Including the builds from GPC 2023 IRP Update Supplemental Filing Errata 12-7-23 PD, PD Capacity Expansion Plans Supplemental - Errata.xlsx and the 2022 IRP ESS RFP from GPC Response to STF-JKA-2-2, Attachment C, attached as Exhibit DG/LM-16.

Q How does the near-term buildout of solar PV in GPC's 2023 IRP Update compare to its Resource Mix Study?

A Similar to BESS, GPC includes much less new solar capacity in its 2023 IRP Update than would be economic based on its 2023 Resource Mix Study. In the 2023 IRP Update, GPC only plans to add 0.2 GW of new solar, as part of a paired solar-storage project.[102] The moderate fuel scenario in the Resource Mix Study shows that it would be economic for GPC to procure 1.5 GW of new solar by 2030,[103] which is over seven times the capacity in the 2023 IRP Update.

Q How should GPC adjust its plans for BESS and solar PV buildout between now and 2030?

A Given the quantity of economic BESS and solar PV built in its own modeling, GPC should focus its near-term procurement efforts on BESS, both paired with solar PV and stand-alone, to address its projected near-term capacity needs. The Company should procure as much BESS and solar as it can economically obtain from the market based on All-Source RFPs.

[102] GPC 2023 IRP Update at 20.

[103] GPC 2023 IRP Update Supplemental Filing Errata 12-7-23 PD, PD Capacity Expansion Plans Supplemental - Errata.xlsx.

5. GPC'S LONG-TERM RESOURCE PLANNING PRACTICES

Q Please summarize your concerns with GPC's long-term planning practices.

A GPC's 2023 Resource Mix Study and its 2023 IRP Update show plans for GPC to maintain[104] [redacted] its existing fleet of coal and gas resources and to build large amounts of new gas combined-cycle capacity.[106] This heavy reliance on fossil fuels will expose ratepayers to fuel price volatility and potentially expensive new regulations, most notably the proposed rules under Section 111 of the *Clean Air Act*. Additionally, GPC's failure to plan for resource retirement and replacement beyond the next few years limits the Commission's ability to effectively oversee the Company's resource planning decisions. GPC must move away from these last-minute planning practices, such as it did with signing the MPC PPA, to allow sufficient time to consider all economic resource options, especially clean energy resource options that can more economically serve the Company's new and existing load.

Q Why should the Commission address long-term planning practices now, rather than waiting for next year's IRP proceeding?

A In this IRP Update, GPC is once again attempting to force the Commission's hand by not planning far enough in advance to allow for consideration of the full range

[104] GPC Response to STF-JKA-2-2, Attachment C.xlsx, attached as Exhibit DG/LM-16.

[105] GPC 2023 IRP Update, TS Technical Appendix, TS Technical Information Supporting the Potential Acquisition of an Additional Ownership Interest in an Existing Generating Asset.

[106] GPC 2023 IRP Update Supplementary Filing Errata 12-7-23 PD, PD Capacity Expansion Plan Supp – Errata.xlsx.

of resource options. The Company is also asking for approval for a PPA that it already signed and executed without properly considering alternatives. Although not directly at issue in the 2023 IRP Update, if the Commission does not consider long-term planning practices now, it will find itself back in the same situation for GPC's 2025 IRP; namely, GPC pushing limited options and an urgent need to immediately approve whatever the Company puts forth.

i. GPC's long-term planning relies heavily on fossil fuels

Q What is the Company's plan for its aging coal and gas assets?

A As shown in Table 6 below, GPC plans to extend the operation of many of its coal and gas plants that it had sought permission to deactivate in its 2022 IRP.[107] Specifically, GPC plans to extend the operation of Bowen Units 1–2 through 2035 (Units 3–4 already have 2035 retirement dates),[108] and delay the retirement of Scherer 3[109] as well as Gaston Units 1–4 and Unit A beyond 2028.[110] Scherer 3 and the Gaston Units all had 2028 retirement dates approved in the Company's 2022 IRP.[111]

[107] Georgia Power Company. 2022. *2022 Integrated Resource Plan*. Docket No. 44160. Page 12; GPC 2023 IRP Update at 27.

[108] GPC 2023 IRP Update at 26-27; Supplemental GPC Response to STF-JKA-2-2, Supplemental Attachment B, attached as Exhibit DG/LM-21.

[109] GPC 2023 IRP Update at 27.

[110] *Id*.; Supplemental GPC Response to STF-JKA-2-2, Supplemental Attachment B.xls, attached as Exhibit DG/LM-21.

[111] GPC 2023 IRP Update at 27.

Table 6. Updated retirement plans for GPC's gas and coal plants

Plant Name	GPC share (MW)	Resource type	Owner	Previous retirement Plan	Proposed retirement date
Bowen Units 1–2	1,538	Coal	GPC	2027	2035
Bowen Units 3–4	1,878	Coal	GPC	2035	2035
Scherer 3	682.5	Coal	GPC	2028	Beyond 2028
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gaston Units 1–4	460	Gas Steam	GPC	2028	Beyond 2028
Gaston Unit A	10	CT	GPC	2028	Beyond 2028
Plant Daniel Unit 2	500	Coal	MPC (PPA)	2027	Beyond 2027
Plant Watson Unit 4	250	Gas Steam	MPC (PPA)	2023	Beyond 2027

Source: See text.

Q Is the Company considering [redacted]?

A [redacted] As part of the 2023 IRP Update original filing, GPC stated that it was negotiating a potential option to acquire an additional ownership interest in an existing asset within the Southern Company Footprint.[112] GPC didn't reveal publicly what that asset is, but in a trade secret appendix the Company revealed that it is [redacted]

[112] Direct Testimony of Grubb, Valle, Evans, and Bush on behalf of Georgia Power Company. Page 41.

[113] GPC 2023 IRP Update, TS Technical Appendix, Technical Information Supporting the Potential Acquisition of an Additional Ownership Interest in an Existing Generation Asset.

[redacted].[114] GPC stated that parties could not come to an agreement at this time, but that the Company will continue to explore other options.[115] Additionally, as discussed above, by signing the PPA with MPC, GPC is extending the life of Plant Daniel.

Q Does the Company plan to construct additional gas capacity?

A Yes. As shown in Table 7 below, in all scenarios in the Resource Mix Study, GPC builds between 8.4 and 10.9 GW of new gas capacity.[116] GPC modeled six scenarios, three of which vary fuel costs: moderate fuel costs (MG0), high fuel costs (HG0), low fuel costs (LG0). The remaining three scenarios examine carbon prices: $20 per ton carbon price (MG20), $50 per ton carbon price (MG50), and an emissions limit (EL). Figure 2 shows GPC's total winter firm capacity in the MG0 scenario; the majority of the Company's firm capacity comes from oil and gas. Additionally, by signing the PPA with MPC, GPC is extending the life of the Plant Watson gas plant.

[114] *Id*.

[115] Direct Testimony of Grubb, Valle, Evans, and Bush on behalf of Georgia Power Company. Page 41.

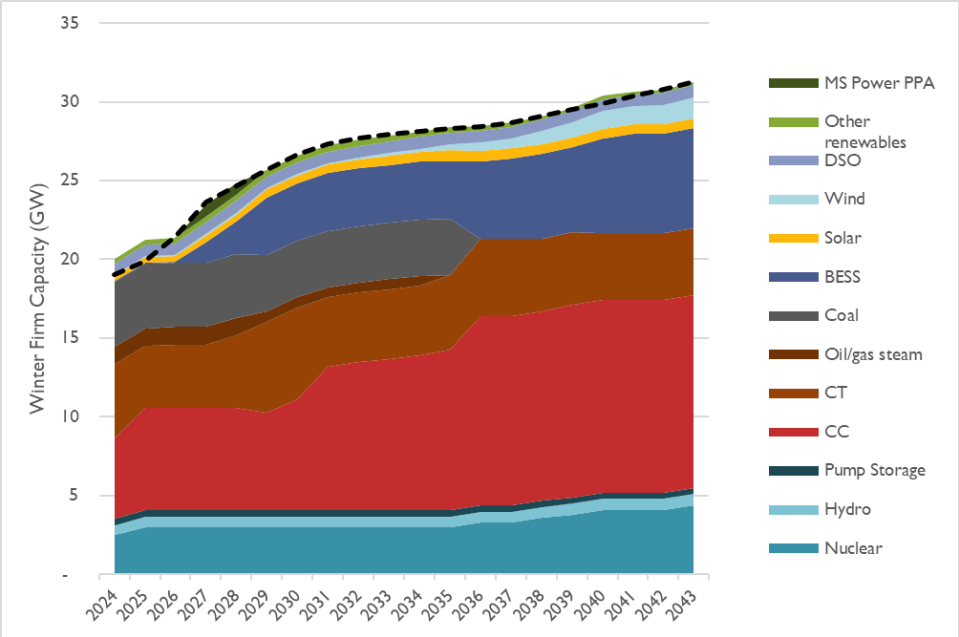
[116] GPC 2023 IRP Update Supplementary Filing Errata 12-7-23 PD, PD Capacity Expansion Plans Supp – Errata.xlsx.

Table 7. Nameplate capacity of cumulative resource additions from the Resource Mix Study in megawatts (GPC only)

	LG0	MG0	HG0	MG20	MG50	EL
Gas	10,860	10,440	8,430	9,390	10,710	9,930
Combined cycle	7,920	8,040	7,890	3,990	900	600
Combined cycle with CCS	30			3,900	7,800	8,220
Combustion turbine	2,910	2,400	540	1,500	2,010	1,110
Nuclear	960	1,410	2,100	2,130	1,950	1,860
Short-duration storage	4,920	6,810	6,270	7,830	8,640	11,190
Medium-duration storage	1,620		300	60	-	-
Solar	10,860	11,610	11,610	11,550	11,520	16,470
Wind	3,330	3,870	5,370	5,700	5,940	5,160

Source: GPC 2023 IRP Update Supplemental Filing Errata 12-7-23, PD Capacity Expansion Plans Supplemental - Errata.xlsx.

Figure 2. Capacity expansion plan for GPC from Resource Mix Study, Scenario MG0 (winter firm capacity)



Source: GPC response to STF-JKA-2-2, Attachment C.xlsx.
Note: Figure breaks out both owned and purchased generating capacity by resource type rather than showing purchased capacity as a separate category.

Q How do resource additions in the high carbon price (MG50) scenario differ from resource additions in the MG0 scenario?

A The largest difference between the two scenarios is that in the MG50 scenario, GPC builds 7.8 GW of gas CC capacity with CCS, while in the MG0 scenario the model builds traditional CC plants with no CCS. Also, in the MG50 scenario, GPC builds 1.8 GW of short-duration BESS and 2.1 GW of wind incremental to what it builds in the MG0 scenarios.

ii. GPC's plan to continue relying on coal, gas, and oil is risky for ratepayers

Q What risks is the Company exposing ratepayers to from its planned expanded dependance on coal, gas, and oil?

A GPC's intention to maintain and expand its portfolio of gas, oil, and coal resources exposes its ratepayers to fuel price volatility and the potential for sizeable additional expenses from proposed and upcoming federal legislation (if finalized), including the 2023 Effluent Limitations Guidelines (ELG) Rule and greenhouse gas regulations under Section 111 of the *Clean Air Act*.

Q Explain the risks posed to ratepayers by fuel price volatility.

A High reliance on gas resources can expose ratepayers to fuel price volatility for which ratepayers cannot plan. Gas is a global commodity, which means that both domestic and global market forces can impact the price and demand for the resource. After roughly doubling from 2019 to 2022, North American liquid natural gas export capacity is projected to double again by 2027, from current levels to

more than 24 billion cubic feet per day.[117] To put this in perspective, US total gas consumption in 2022 averaged rough 88 billion cubic feet per day.[118] The global market consumption effect on prices in the United States will continue to increase significantly over even just the next few years.

When the market is constrained and prices spike, those costs are passed on directly to ratepayers. For example, DTE Electric Company in Michigan just filed its 2022 Fuel Reconciliation Docket and noted that gas spending was 74 percent higher than planned. These higher-than-expected prices resulted in large part from the Russian invasion of Ukraine, and European gas customers turning increasingly to U.S. gas. As a result, DTE is requesting to recover an additional $154 million for 2022 fuel costs alone.[119] Absent action from the Michigan Commission, DTE and its shareholders are not impacted by these gas price spikes—these costs are entirely passed on to ratepayers. The same phenomenon could happen just as easily in Georgia or elsewhere in the Southeast. GPC should take this into account in its IRP modeling, and in planning its future resource mix.

Q What other risks does GPC face from reliance on gas resources?

A As discussed above, firm gas pipeline capacity is constrained in GPC's service area. That means that unless an expensive new pipeline is built, the Company does not

[117] Victoria Zaretskaya and Max Ober, U.S. Energy Information Administration, "LNG export capacity from North America is likely to more than double through 2027," (Nov. 13, 2023), available at: https://www.eia.gov/todayinenergy/detail.php?id=60944.

[118] U.S. Energy Information Administration, "Natural Gas Consumption by End Use," (Oct. 2023) available at: https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a htm.

[119] DTE Elec. Co. 2023. *Exhibit A-7.* Mich. Pub. Serv. Comm'n Docket No. E-21051. March 31, 2023.

have a firm source of gas to supply new gas resources. Any new gas resource without a firm supply of fuel is not actually a firm resource unless it can also operate on oil. As discussed above, operation on oil is [redacted] times more expensive, dirty, and overall a bad long-term strategy—especially when there are cost-effective, lower-cost, and lower-risk alternatives.

Q What risks does GPC face from continued, and even [redacted], reliance on coal assets?

A The coal market has seen dramatic price volatility in some parts of the United States over the past few years.[120] There have also been labor challenges both at the mines and the railroad companies that transport the coal, as coal workers demand better pay and have more options in the labor market. Additionally, as more and more coal plants across the United States retire and the demand for coal contracts, this combined with the labor challenges could result in consolidation among coal companies and subsequently higher prices.[121]

Coal use was down in 2023 and never reached more than 20 percent of power market share (through October). This is novel because market share had been around 20 percent each month between 2020–2022; and prior to 2020, coal had

[120] U.S. Energy Information Administration, "Coal Markets." Available at https://www.eia.gov/coal/markets/.

[121] Duke Energy. "Coal Retirement Analysis," available at: https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-f-coal-retirement-study.pdf?rev=4c1c4df441a14248b2e23ba0368d9855.

never comprised less than 20 percent market in any month.[122] Additionally, risks from increased environmental regulation, as we will discuss next, could result in higher costs and higher risks. Higher risk impacts not just resource planning economics but company risk profiles which can lead to downgraded credit ratings, and that can impact access to capital.

Q Explain the proposed 2023 ELG Rule and its impact on the Bowen and Scherer coal plants.

A The proposed 2023 ELG Rule strengthens the discharge standards for three types of wastewater produced by coal-fired units: flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate.[123] If the rule is finalized, GPC could incur costs at Bowen for two flue gas desulfurization measures (a membrane-based wastewater treatment system and a zero-liquid discharge system) and a wastewater treatment system for combustion residual leachate.[124] Similarly, Scherer could require retrofits to improve its treatment of combustion residual leachate.[125] GPC estimates that a membrane-based flue gas

[122] Institute for Energy Economics and Financial Analysis, "Coal Use at U.S. Power Plants Continues Downward Spiral; Full Impact on Mines to be Felt in 2024," (Nov. 2, 2023), available at: https://ieefa.org/resources/coal-use-us-power-plants-continues-downward-spiral-full-impact-mines-be-felt-2024.

[123] 88 Fed. Reg. 18824 (Mar. 29, 2023).

[124] GPC Response to STF-PIA-10-6, attached as Exhibit DG/LM-22.

[125] *Id*.

desulfurization system at Bowen would cost approximately $580 million but does not yet have estimates for the costs of the other retrofits.[126]

Q Explain the recently proposed Section 111 Rules and their impact on both existing and new fossil resources.

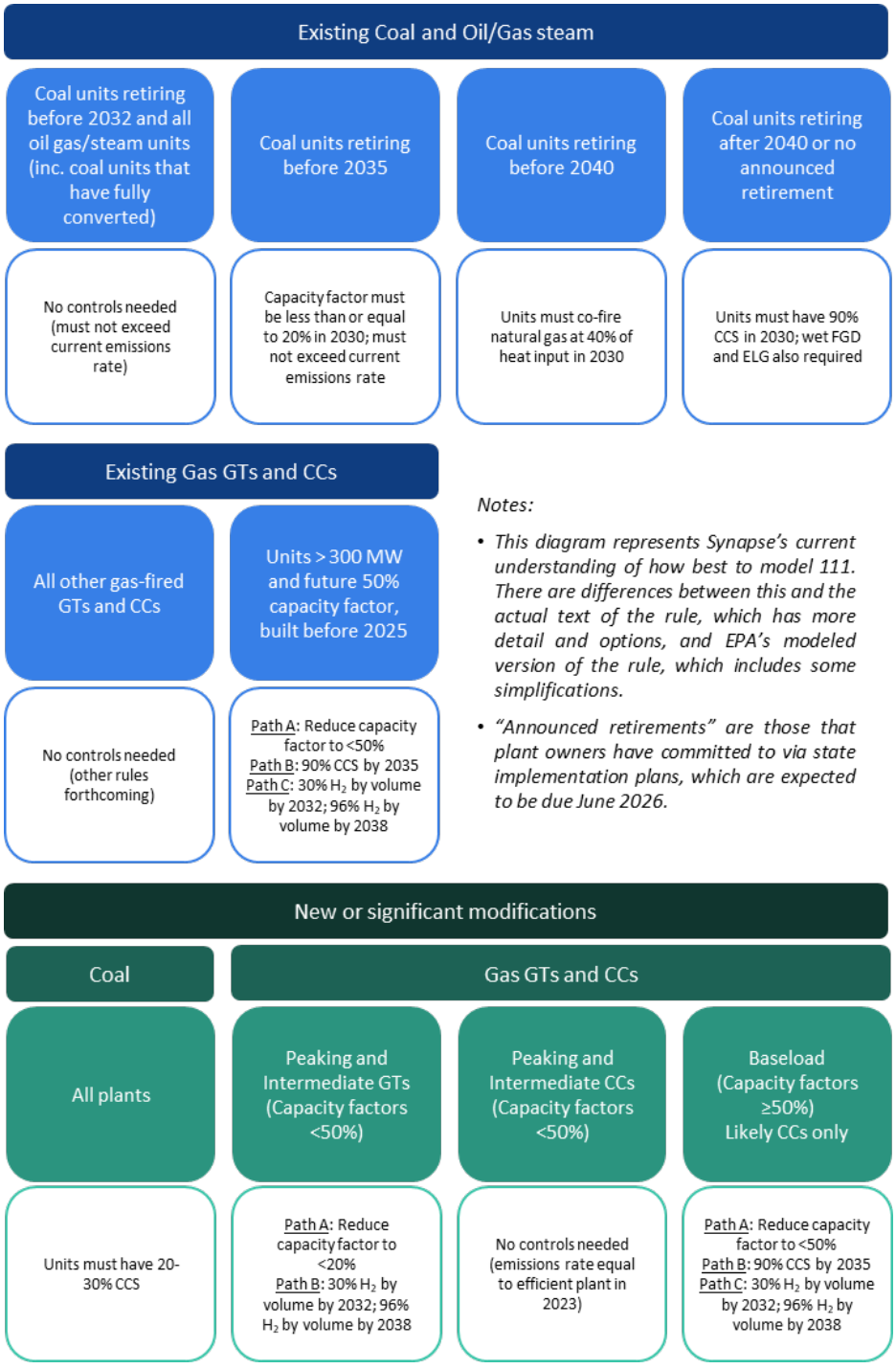
A The proposed Section 111 Rules apply to both coal- and gas-fired units, existing and new, and provide several pathways for compliance (Figure 3).[127] These pathways differ based on: (1) whether the unit is coal or gas; (2) whether the unit is existing or new; (3) how much the unit runs; and (4) when the unit is scheduled to retire. GPC does not include any new coal in its Resource Mix Study, so the Section 111 Rules would apply only to its existing coal, existing gas, and new gas resources. Importantly, if GPC were to acquire [redacted] as it contemplated in its original 2023 IRP Update filing,[128] the Section 111 Rules would apply to those units as well. Additionally, even though the PPA with MPC currently ends in 2028, if GPC were to try and extend it, beyond 2032 MPC would be obligated to comply with the proposed rules at Plant Daniel and Plant Watson.

[126] *Id*.

[127] 88 Fed. Reg. 33240 (May 23, 2023).

[128] GPC 2023 IRP Update, Technical Appendix, TS Technical Information Supporting the Potential Acquisition of an Additional Ownership Interest in an Existing Generation Asset.

Figure 3. Synapse's understanding of EPA's proposed Section 111 Rules



Q Did GPC incorporate the proposed Section 111 Rules in its Resource Mix Study?

A No. The Company did not explicitly model the proposed Section 111 Rules, stating that "a compliance evaluation cannot be completed at this time, because uncertainty remains in the compliance options and requirements for existing facilities until the development of the Georgia state plan required by the rule."[129] GPC did model three carbon pressure scenarios (see Table 7 above). Regardless of uncertainty around the rule's final form, GPC should have conducted a model sensitivity run at the very least to understand how the rule would impact its current resource plan. Failing to plan for a proposed regulation doesn't make it less likely to be finalized, but it does make GPC less likely to be prepared to comply.

Q How will the Section 111 Rules impact each of GPC's fossil fuel power plants, including their planned retirement dates and operational decisions?

A If the proposed Section 111 Rules are finalized, Georgia Power will need to adjust its plans for its coal and gas units as shown in Table 8 below. It is simply not economic for GPC to maintain its current plan at each plant if the proposed rule is finalized.

Bowen and Scherer 1 and 2 coal plants are currently scheduled to retire in 2035.[130] These units will need to be retrofitted to co-fire with natural gas starting in 2030 if

[129] GPC Response to STF-PIA-10-7, attached as Exhibit DG/LM-23.

[130] GPC 2023 IRP Update at 27; Supplemental GPC Response to STF-JKA-2-2, Supplemental Attachment B, attached as Exhibit DG/LM-21.

they are to stay online through 2035. But if the retirement dates were shifted earlier, to 2032, they do not need to do anything to comply with the proposed Section 111 Rules. This would allow them to avoid costly investments for conversion to co-fire on gas. Scherer 3 and Gaston 1-4 will not be required to take any compliance actions unless GPC extends their retirement dates to 2032 or beyond. Any existing and new CC units will have to cap their capacity factors at 50 percent starting in 2032 or else install 90 percent CCS by 2035, or co-fire with hydrogen starting in 2032. It is most likely that limiting utilization to a 50 percent capacity factor will be the most economic compliance option.

Table 8. Section 111 compliance options at GPC's coal- and gas-fired power plants based on current retirement dates

Power Plant	Type	Retirement Date (EOY)	111 Compliance Options
Bowen Units 1–4	Coal	2035	Co-fire natural gas at 40% starting in 2030
Scherer Units 1–2	Coal	2035	Co-fire natural gas at 40% starting in 2030
Scherer Unit 3	Coal	2028	No action required unless GPC delays retirement beyond 2032
Gaston Units 1–4	Gas Steam	2028	No action required unless GPC delays retirement beyond 2032
Yates Units 6–7	Gas Steam	2034	Capacity factor limit of 20% starting in 2030
Existing CCs	CC	Various	Reduce capacity factor to under 50% starting 2032, 90% CCS by 2035, 30% H_2 by 2032 and 96% H_2 by 2038
New CCs	CC	None	Reduce capacity factor to under 50% starting 2032, 90% CCS by 2035, 30% H_2 by 2032 and 96% H_2 by 2038
Existing CTs	CT	Various	No action required
New CTs	CT	None	20% capacity factor limit or 30% H_2 by 2032

Q Has GPC adequately considered the risks posed by the proposed Section 111 Rules in its planning?

A No. GPC stated in discovery that it did not include any assumptions regarding the proposed Section 111 rules in the 2023 IRP Update.[131] GPC should add a scenario to its Resource Mix Study that fully analyzes compliance with the proposed Section 111 Rules. Even if the there is uncertainty about some details of the rule, the Company needs to start understanding the likely impacts of Section 111 now so that it can begin positioning itself for future compliance, rather than investing in assets that will require either expensive retrofits or capacity factor limits within a few years. Given that neither CCS nor hydrogen blending are currently demonstrated at scale, capacity factor limits may be the preferable method for most covered resources to comply with the Section 111 Rules in the near term. This could significantly alter GPC's long-term planning for both existing fossil plants and new build plants.

Q Do GPC's carbon pressure scenarios provide insight into the costs that the Section 111 Rules could impose on the Company?

A No. These scenarios provide minimal insight into the potential impact of the Section 111 Rules on the Company, contrary to GPC's claim that "the implications of a final EPA 111 rule are captured within the range of carbon pressure scenarios included in the 2023 IRP Update."[132] The Company only included very limited

[131] GPC Response to STF-PIA-7-4, attached as Exhibit DG/LM-24.
[132] *Id*.

potential compliance pathways in its modeling, it also did not account for the risk associated with nascent CCS technologies, and it has not analyzed the impacts of the Section 111 Rules on existing units such as Bowen and Scherer.

The carbon pressure scenarios rely on large buildouts of CC with CCS (3.9–8.2 GW).[133] CCS is expensive, and the cost is even more unknown given that there are no operational gas plants with CCS currently existing in the United States to look to as data points.[134]

Q Explain the risks associated with CCS that GPC has not captured in its modeling.

A The biggest risk with CCS is cost over-runs. While the 45 (q) tax credit appears lucrative, the level of uncertainty around the cost is much greater than for existing non-emitting technologies like solar and storage, and thus, and thus not accurately captured in the Company's analysis. CCS technology has not been deployed at scale yet, so cost estimates are likely to be wrong. And given how expensive CCS projects are, that could mean hundreds of millions to even billions in underestimated costs. It is also worth noting that, given Southern Company's experience with gasification and carbon capture at the Kemper Project, it is concerning that the Company is considering jumping back into another carbon

[133] GPC 2023 IRP Update Supplementary Filing Errata 23-7-23 PD, PD Capacity Expansion Plans Supp – Errata.xlsx.

[134] Schlissel, D. *Carbon Capture from Coal Plants: A Step in the Wrong Direction* (2021). Institute for Energy Economics and Financial Analysis.

capture project. The Kemper project cost escalated to an estimated three times its initial project estimate (from $2.5 billion to $7.5 billion)[135] before the Mississippi Commission ultimately pulled the plug on the project and ordered MPC to continue to operate the plant on just natural gas.[136] MPC demolished the gasification infrastructure in dramatic fashion in 2021.[137] There is no guarantee that if GPC attempted another project of this magnitude, it would not face similar cost challenges.

There is also uncertainty surrounding the level of performance that CCS equipment will achieve. Since plants must achieve at least 90 percent carbon capture to be eligible for the tax credit and to satisfy the Section 111 Rules, this makes CCS a risky strategy for compliance.

Q Are there steps that GPC should take now to avoid future expense and risk from exposure to fuel price volatility, the 2023 ELG Rule, and Section 111 Rules?

A Yes. In addition to studying compliance pathways in its Resource Mix Study, GPC should take steps to procure renewables and battery storage as rapidly as possible, with a particular focus on capacity from the market, as we discuss in more detail below. Only once it has exhausted its ability to economically procure BESS and solar PV (paired and stand-alone) through issuing All-Source RFPs to the market

[135] Kristi Swartz, "Southern Co.'s clean coal plant hits a dead end," EnergyWire (June 22. 2027), available at https://subscriber.politicopro.com/article/eenews/1060056418.

[136] Kristi Swartz, *The Kemper project just collapsed. What it signifies for CCS.* EnergyWire, October 2021, available at https://www.eenews net/articles/the-kemper-project-just-collapsed-what-it-signifies-for-ccs/.

[137] *Id*.

and rousting evaluating self-build costs and options, should it turn to other resource options.

iii. GPC needs to plan proactively going forward by issuing All-Source RFPs and requesting Commission approval for new resources far enough in advance to allow for consideration of alternatives

Q Is the Company planning far enough ahead to allow for adequate Commission oversight?

A No. GPC's failure to account for upcoming load growth in its 2022 IRP means that it is now too late to bring most new resources online before the shortfall begins in winter 2025/2026. This has limited the Commission's ability to effectively oversee GPC's resource planning decisions in this docket. Furthermore, the resources that the Company proposes in the 2023 IRP Update are stopgap solutions that resolve its capacity shortfall only through the winter of 2027/2028.[138] If GPC experiences the full amount of load growth that it currently projects, this pattern may well continue with GPC's 2025 IRP. If the Company does not ramp up its evaluation and procurement of new resources by issuing All-Source RFPs and evaluating self-build options for BESS and solar PV, by the time GPC files the 2025 IRP, it will again be too late to procure most types of new resources before the next capacity shortfall.

[138] GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B, attached as Exhibit DG/LM-21.

GPC's failure to plan for resource retirement and replacement beyond the next few years has the effect of locking ratepayers into decisions the Company has made, even ones that have not yet been approved or considered by the Commission. GPC limits the Commission's ability to effectively oversee its resource planning decisions by delaying resources decisions until the timing eliminates any real choice.

Q Give a specific example of GPC's incremental decision-making forcing the Commission's hand.

A The Company declined to address the possible extension in Scherer 3 and Gaston 1–4 in this IRP Update,[139] despite the fact that their scheduled retirement in 2028 is only four years away.[140] By the time of the next IRP in 2025, there will be even less time to procure alternate resources in lieu of extending these units. On average, the Company estimates that it takes [redacted] to construct new solar capacity and [redacted] to construct new battery storage, not including time to conduct an RFP.[141] Given that the Company is aware of these construction timelines, its consistent pattern of leaving less time than this to procure replacement resources is poor planning that the Commission should require GPC to correct.

[139] GPC 2023 IRP Update at 27; GPC 2023 IRP Update, TS Technical Appendix, TS Technical Information Supporting the Potential Acquisition of Additional Ownership in an Existing Generation Asset.
[140] GPC Response to STF-JKA-2-8, attached as Exhibit DG/LM-25.
[141] GPC Response to TS STF-PIA-10-1, attached as Exhibit DG/LM-19.

Q How should GPC change its planning in the future?

A Battery storage, solar, and wind provide low-cost capacity and energy, but siting and constructing these resources takes time. As a result, just-in-time resource planning is increasingly inadequate to meet the needs of ratepayers now and will likely become even more so over the next decade and beyond. This is especially true given that GPC needs to meet load growth from new businesses moving into Georgia, many of which have clean energy goals. To adapt to changing paradigms in the power sector—including broad-scale decarbonization—GPC should recognize the energy value of renewables and push to bring renewables online on a rolling basis and whenever they are economically available, rather than trying to align resource additions perfectly with capacity needs. GPC should be sure that its next RFP is All-Source (open to all resources) and that it communicates to the market that GPC is seeking as much BESS and solar as possible. The Company should also evaluate its own ability to self-build BESS and solar PV.

Early renewable procurement will ensure that GPC can procure sufficient replacement resources without suspending RFP procedures, as it requests in the 2023 IRP Update. This approach will save ratepayers money. It will also help GPC keep pace with national policy development, and it will give the Company an opportunity to learn how to manage a system with a high level of renewable penetration, providing a safety net for system reliability.

Q Does this conclude your testimony?

A Yes.

Appendix A: List of Exhibits

DG-1 ..... Devi Glick Resume

LM-1 ..... Lucy Metz Resume

DG/LM-1 ..... GPC Response to STF-DEA-1-5

DG/LM-2 ..... GPC Response to PD STF-JKA-2-22

DG/LM-3 ..... GPC Response to TS STF-PIA-7-15, TS Attachments A-P

DG/LM-4 ..... GPC Response to TS STF-JKA-2-19, Attachment B

DG/LM-5 ..... GPC Response to PD STF-JKA-6-5

DG/LM-6 ..... GPC Response to PD STF-JKA 4-10

DG/LM-7 ..... GPC Response to PD STF-JKA-2-20

DG/LM-8 ..... GPC Response to STF-JKA-4-19

DG/LM-9 ..... GPC Response to PD STF-JKA-6-7

DG/LM-10 ..... GPC Response to TS STF-PIA-10-3

DG/LM-11 ..... GPC Suppl. Response to STF-JKA-2-2

DG/LM-12 ..... GPC Response to TS STF-DEA-3-6, Attachment G

DG/LM-13 .. GPC Suppl. Response to TS STF-DEA-3-6, Suppl. Attachment G

DG/LM-14 ..... GPC Response to STF-JKA-2-14

DG/LM-15 ..... GPC Response to STF-JKA-3-10

DG/LM-16 ..... GPC Response to STF-JKA-2-2, Attachment C

DG/LM-17 ..... GPC Response to STF-JKA-4-14

DG/LM-18 ..... GPC Response to STF-JKA-2-11, Attachment F

DG/LM-19 ..... GPC Response to TS STF-PIA-10-1

DG/LM-20 ..... GPC Response to PD STF-JKA-1-4

DG/LM-21 ..... GPC Suppl. Response to STF-JKA-2-2, Suppl. Attachment B

DG/LM-22 ..... GPC Response to STF-PIA-10-6

DG/LM-23 ..... GPC Response to STF-PIA-10-7

DG/LM-24 ..... GPC Response to STF-PIA-7-4

DG/LM-25 ..... GPC Response to STF-JKA-2-8

DG-1:
Devi Glick Resume

Devi Glick, Senior Principal

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7050
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Principal*, May 2022 – Present; *Principal Associate*, June 2021 – May 2022; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.

- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Kwok, S., D. Glick, R. Anderson, T. Gyalmo. 2023. *Review of Southwestern Public Service Company 2023 Integrated Resource Plan*. Synapse Energy Economics for Sierra Club.

Kwok, S., J. Smith, D. Glick. 2023. *Review of Cleco Power's 2021 IRP Report.* Synapse Energy Economics for Sierra Club.

Addleton, I., D. Glick, R. Wilson. 2021. *Georgia Power's Uneconomic Coal Practices Cost Customers Millions*. Synapse Energy Economics for Sierra Club.

Glick, D., P. Eash-Gates, J. Hall, A. Takasugi. 2021. *A Clean Energy Future for MidAmerican and Iowa.* Synapse Energy Economics for Sierra Club, Iowa Environmental Council, and the Environmental Law and Policy Center.

Glick, D., S. Kwok. 2021 *Review of Southwestern Public Service Company's 2021 IRP and Tolk Analysis.* Synapse Energy Economics for Sierra Club.

Glick, D., P. Eash-Gates, S. Kwok, J. Tabernero, R. Wilson. 2021. *A Clean Energy Future for Tampa.* Synapse Energy Economics for Sierra Club.

Glick, D. *2021. Synapse Comments and Surreply Comments to the Minnesota Public Utility Commission in response to Otter Tail Power's 2021 Compliance Filing* Docket E-999/CI-19-704. Synapse Energy Economics for Sierra Club.

Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

Eash-Gates, P., B. Fagan, D. Glick. 2020. *Alternatives to the Surry-Skiffes Creek 500 kV Transmission Line.* Synapse Energy Economics for the National Parks Conservation Association.

Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets.* Synapse Energy Economics for Climate Majority Project.

Glick, D., D. Bhandari, C. Roberto, T. Woolf. 2020. *Review of benefit-cost analysis for the EPA's proposed revisions to the 2015 Steam Electric Effluent Limitations Guidelines.* Synapse Energy Economics for Earthjustice and Environmental Integrity Project.

Glick, D., J. Frost, B. Biewald. 2020. *The Benefits of an All-Source RFP in Duke Energy Indiana's 2021 IRP Process.* Synapse Energy Economics for Energy Matters Community Coalition.

Camp, E., B. Fagan, J. Frost, N. Garner, D. Glick, A. Hopkins, A. Napoleon, K. Takahashi, D. White, M. Whited, R. Wilson. 2019. *Phase 2 Report on Muskrat Falls Project Rate Mitigation, Revision 1 – September 25, 2019.* Synapse Energy Economics for the Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Camp, E., A. Hopkins, D. Bhandari, N. Garner, A. Allison, N. Peluso, B. Havumaki, D. Glick. 2019. *The Future of Energy Storage in Colorado: Opportunities, Barriers, Analysis, and Policy Recommendations.* Synapse Energy Office for the Colorado Energy Office.

Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project*. Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Synapse Energy

Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet to and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

TESTIMONY

Louisiana Public Service Commission (Docket No. U-36923): Direct Testimony of Devi Glick in the Application of Cleco Power LLC for: (1) Implementation of changes in rates to be effective July 1, 2024; and (2) extension of existing formula rate plan. On behalf of Sierra Club. February 5, 2024.

Public Service Commission of South Carolina (Docket No. 2023-154-E): Supplemental Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. January 29, 2024.

Public Service Commission of South Carolina (Docket No. 2023-154-E): Surrebuttal Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. November 17, 2023.

Public Utilities Commission of Ohio (Case No. 21-477-EL-RDR): Direct Testimony of Devi Glick in the Matter of the OVEC Generation Purchase Rider Audits Required by 4928.148 for Duke Energy Ohio, Inc. the Dayton Power and Light Company, and AEP Ohio. On behalf of Union of Concerned Scientists and the Citizens Utility Board. October 10, 2023.

Public Service Commission of South Carolina (Docket No. 2023-154-E): Direct Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. September 22, 2023.

Public Utilities Commission of Ohio (Case No. 20-165-EL-RDR): Direct Testimony of Devi Glick in the matter of the review of the Reconciliation Rider of the Dayton Power and Light Company. On behalf of Office of the Ohio Consumers' Counsel. September 12, 2023.

Virginia State Corporation Commission (Case No. PUR-2023-00066): Direct Testimony of Devi Glick in re: Virginia Electric and Power Company's 2023 Integrated Resource Plan filing pursuant to Virginia Code to §56-597 *et seq.* On behalf of Sierra Club. August 8, 2023.

Public Utility Commission of Texas (PUC Docket No. 54634): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. August 4, 2023

Arizona Corporation Commission (Docket No. E-1345A-22-0144): Surrebuttal Testimony of Devi Glick in the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of Sierra Club. July 26, 2023.

Arizona Corporation Commission (Docket No. E-01345A-22-0144): Direct Testimony of Devi Glick in the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of Sierra Club. June 5, 2023.

Virginia State Corporation Commission (Case No. PUR-2023-00005): Direct Testimony of Devi Glick in the Petition of Virginia Electric & Power Company for revision of rate adjustment clause, Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 23, 2023.

New Mexico Public Regulation Commission (Case No, 22-00286-UT): Direct Testimony of Devi Glick in the matter of Southwestern Public Service Company's application for: (1) Revisions of its retail rates under advance no. 312; (2) Authority to abandon the Plant X Unit 1, Plant X Unit 2, and Cunningham Unit 1 Generating Stations and amend the abandonment date of the Tolk Generating Station; and (3) other associated relief. On behalf of Sierra Club. April 21, 2023.

Michigan Public Service Commission (Case No. U-20805): Direct Testimony of Devi Glick in the matter of the Application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ended December 31, 2021. On behalf of Michigan Attorney General. April 17, 2023.

Michigan Public Service Commission (Case No. U-21261): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval to implement a Power Supply Cost Recovery Plan for the twelve months ending December 31, 2023. On Behalf of Sierra Club. March 23, 2023.

New Mexico Public Regulation Commission (Case No. 19-00099-UT / 19-00348-UT): Direct Testimony of Devi Glick in the matter of El Paso Electric Company's Application for Approval of Long-Term Purchased Power Agreements with Hecate Energy Santa Teresa, LLC, Buena Vista Energy, LLC, and Canutillo Energy Center LLC. On Behalf of New Mexico Office of the Attorney General, January 23, 2023.

Arizona Corporation Commission (Docket No. E-01933A-22-0107): Direct Testimony of Devi Glick in the matter of the application of Tucson Electric Power Company for the establishment of just and

reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of Tucson Electric Power Company devoted to its operations throughout the state of Arizona for related approvals. On Behalf of Sierra Club. January 11, 2023.

New Mexico Public Regulation Commission (Case No. 22-00093-UT): Direct Testimony of Devi Glick in the amended application for approval of El Paso Electric Company's 2022 renewable energy act plan pursuant to the renewable energy act and 17.9.572 NMAC, and sixth revised rate no. 38-RPS cost rider. On Behalf of New Mexico Office of the Attorney General, January 9, 2023.

Iowa Utilities Board (Docket No. RPU-2022-0001): Supplemental Direct and Rebuttal Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. November 21, 2022.

Public Utility Commission of Texas (PUC Docket No. 53719): Direct Testimony of Devi Glick in the application of Entergy Texas, Inc. for authority to change rates. On behalf of Sierra Club. October 26, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00051): Direct Testimony of Devi Glick in re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Virginia Code §56-597 *et seq*. On behalf of Sierra Club. September 2, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Surrebuttal Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. August 16, 2022.

Iowa Utilities Board (Docket No. RPU-2022-0001): Direct Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. July 29, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Direct Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. June 8, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00006): Direct Testimony of Devi Glick in the petition of Virginia Electric & Power Company for revision of rate adjustment clause: Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 24, 2022.

Oklahoma Corporation Commission (Case No. PUD 202100164): Direct Testimony of Devi Glick in the matter of the application of Oklahoma gas and electric company for an order of the Commission authorizing application to modify its rates, charges, and tariffs for retail electric service in Oklahoma. On behalf of Sierra Club. April 27, 2022.

Public Utility Commission of Texas (PUC Docket No. 52485): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. March 25, 2022.

Public Utility Commission of Texas (PUC Docket No. 52487): Direct Testimony of Devi Glick in the application of Entergy Texas Inc. to amend its certificate of convenience and necessity to construct Orange County Advanced Power Station. On behalf of Sierra Club. March 18, 2022.

Michigan Public Service Commission (Case No. U-21052): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and Factors (2022). On Behalf of Sierra Club. March 9, 2022.

Arkansas Public Service Commission (Docket No. 21-070-U): Surrebuttal Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for approval of a general change in rate and tariffs. On behalf of Sierra Club. February 17, 2022.

New Mexico Public Regulation Commission (Case No. 21-00200-UT): Direct Testimony of Devi Glick in the Matter of the Southwestern Public Service Company's application to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. January 14, 2022.

Public Utilities Commission of Ohio (Case No. 18-1004-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Power Purchase Agreement Rider of Ohio Power Company for 2018 and 2019. On behalf of the Office of the Ohio Consumer's Counsel. December 29, 2021.

Arkansas Public Service Commission (Docket No. 21-070-U): Direct Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs. On behalf of Sierra Club. December 7, 2021.

Michigan Public Service Commission (Case No. U-20528): Direct Testimony of Devi Glick in the matter of the Application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-20527) for the 12-month period ending December 31, 2020. On behalf of Michigan Environmental Council. November 23, 2021.

Public Utilities Commission of Ohio (Case No. 20-167-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Reconciliation Rider of Duke Energy Ohio, Inc. On behalf of The Office of the Ohio Consumer's Counsel. October 26, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase III Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. October 6, 2021.

Public Service Commission of South Carolina (Docket No, 2021-3-E): Direct Testimony of Devi Glick in the matter of the annual review of base rates for fuel costs for Duke Energy Carolinas, LLC (for potential

increase or decrease in fuel adjustment and gas adjustment). On behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy. September 10, 2021.

North Carolina Utilities Commission (Docket No. E-2, Sub 1272): Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

Michigan Public Service Commission (Docket No. U-20530): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ending December 31, 2020. On behalf of the Michigan Attorney General. August 24, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase I Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

Public Utility Commission of Texas (PUC Docket No. 51415): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan. On behalf of the Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Reply to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Public Utility Commission of Texas (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. March 23, 2018.

Resume updated August 2023

LM-1:
Lucy Metz Resume

Lucy Metz, Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-904-9764
lmetz@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Associate* April 2023 – Present; *Research Associate,* July 2022 – April 2023

- Consults on energy-sector issues, including building decarbonization, electric utility resource planning, state and local climate policy, and the future of gas
- Supports the development of comments and testimony in integrated resource planning dockets across the country
- Conducts analysis using Synapse's Building Decarbonization Calculator (BDC), a stock turnover model that calculates the emissions and energy impacts of heat pump adoption
- Produces data visualization tools in R, including interactive webtool of U.S. industrial emitters
- Assists with power sector dispatch modeling using EnCompass
- Co-developer of Synapse spreadsheet model comparing the lifetime cost and performance of district geothermal systems and air-source heat pumps across a variety of climate zones

Laboratory of Dr. Alexander Barron, Department of Environmental Science and Policy, Smith College, Northampton, MA. *Research Assistant*, June 2020 – May 2022

- Co-authored paper on carbon neutrality initiatives in higher education
- Designed data visualization and analysis for USREP-ReEDS modeling of Clean Air Act policy
- Calculated CO_2 emissions reductions achievable under Massachusetts climate legislation and drafted white paper with results

Co-Equal, Washington, D.C. *Policy Intern*, February 2021 – March 2022.

- Performed analysis on a wide range of policy topics requested by members of Congress
- Finalized economic modeling study for public release and presented results
- Coordinated with research team at MIT and Co-Equal to meet policy-relevant deadlines

EDUCATION

Smith College, Northampton, MA
Bachelor of Science in Engineering Science, *Magna Cum Laude with Highest Honors*, 2022

SKILLS

Computer: Excel, R, EnCompass, MATLAB, Mathematica, ENERGY STAR Portfolio Manager

Languages: Spanish (proficient)

PUBLICATIONS

Eash-Gates, P., **L. Metz**, K. Schultz, S. Kwok, A. Hopkins. *Connecticut Comprehensive Energy Strategy: Buildings White Paper*. Prepared by Synapse Energy Economics for Connecticut Department of Energy and Environmental Protection. Forthcoming.

Synapse Energy Economics and Connecticut Department of Energy and Environmental Protection. "Buildings and Industry." In *Connecticut 2023 Comprehensive Energy Strategy*. Forthcoming.

Eash-Gates, P., **L. Metz**, S. Kwok, K. Schultz, K. Takahashi. *Pathways for Connecticut Building Decarbonization: Analysis of Thermal Decarbonization Scenarios Aligned to the Global Warming Solutions Act.* Prepared by Synapse Energy Economics for Connecticut Department of Energy and Environmental Protection. Forthcoming.

Metz, L., A. Napoleon, P. Eash-Gates. *Memo: Equity Metrics for Building Thermal Decarbonization in Connecticut.* Prepared by Synapse Energy Economics for Connecticut Department of Energy and Environmental Protection. Forthcoming.

Metz, L., E. Carlson, O. Griot. 2023. *Methane Waste and Pollution State Factsheets.* Synapse Energy Economics for the Environmental Defense Fund.

Eash-Gates, P., O. Griot, A. Hopkins, **L. Metz**, E. Sinclair, J. Smith. 2023. *Coming Clean on Industrial Emissions: Challenges, Inequities, and Opportunities in U.S. Steel, Aluminum, Cement, and Coke.* Prepared by Synapse Energy Economics for Sierra Club.

Frost, J., P. Knight, S. Sharaf, **L. Metz**, and S. Kwok. 2023. *RGGI's Economic Benefits for Pennsylvania: Exploring the benefits of the Regional Greenhouse Gas Initiative.* Prepared by Synapse Energy Economics for Evergreen Collaborative.

Metz, L., M. Whited, P. Rhodes, E. Carlson. 2023. *Distribution System Investments to Enable Medium- and Heavy-Duty Vehicle Electrification.* Synapse Energy Economics for the Environmental Defense Fund.

Knight, P., J. Frost, T. Fitch, E. Sinclair, J. Tabernero, O. Griot, B. Havumaki, J. Smith, **L. Metz**, S. Chavin. 2023. *TVA's Clean Energy Future: Charting a course to decarbonization in the Tennessee Valley.* Synapse Energy Economics for GridLab and Center for Biological Diversity.

Yuan, M., A. Barron, N. Selin, P. Picciano, **L. Metz**, J. Reilly, and H. Jacoby. 2022. "Meeting U.S. greenhouse gas emissions goals with the international air pollution provision of the Clean Air Act." *Environmental Research Letters* 17 (5): 054019.

Barron, A., M. Domeshek, **L. Metz**, L. Draucker, and A. Strong. 2021. "Carbon neutrality should not be the end goal: Lessons for institutional climate action from U.S. higher education." *One Earth* 4 (9): 1248–1258.

Longnecker, E., **L. Metz**, R. Miller, and A. Berke. 2021. “Probing Liquid–Liquid Phase Separation in Secondary Organic Aerosol Mimicking Solutions Using Articulated Straws.” *ACS Omega* 6 (49): 33436–33442.

Figueroa, L., M. Blinder, C. Grincavitch, A. Jelinek, E. Mann, L. Merva, **L. Metz**, A. Zhao, R. Irwin, S. McArt, and L. Adler. 2019. “Bee pathogen transmission dynamics: Deposition, persistence and acquisition on flowers.” *Proceedings of the Royal Society B*, 286: 20190603.

Resume updated February 2024

DG/LM-1:
GPC Response to STF-DEA-1-5

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF- DEA-1-5

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF- DEA-1-5 ("Response"). In the Response, the Company has provided an additional load forecast sensitivity. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives 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 its disclosure or use. Specifically, the Information contains competitively sensitive commercial and strategic information related to Georgia Power's projected load forecasts and corresponding short- and long-term capacity needs. The Information includes the Company's short- and long-term forecast estimates and impacts, competitive choice opportunities, and capacity need estimates. Public dissemination of the Information would allow Georgia Power's competitors, suppliers, and customers access to the Company's anticipated load strategies and objectives, thereby bestowing insight into the Company's strategic initiatives and forecasting capabilities. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can structure their offers for competitive choice opportunities based on the Information rather than their own costs, capacity, abilities, strategies, or analysis. Any sensitive budgetary Information, if disseminated, would provide insight to competitors regarding the Company's financial positions, performance, and status. Further, prospective bidders may artificially set bid prices based on the Information to their advantage, preventing the Company from securing the best cost resources for customers.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-DEA-1-5

Question:

Refer to the 2023 IRP Update Load and Energy Forecast, p. 3, noting that the analysis of the economic development loads use a P95 load value.

a. Please explain why GPC decided on a P95 load value rather than a P50 or other level. How does GPC incorporate risk of over-supply in the decision-making?
b. Please provide the P50 and P75 forecast of economic development loads.
c. Please provide an updated load forecast and annual capacity balancing using the P50 and P75 values provided in response to part (b).

Response:

a. Georgia Power selected a P95 load value in response to the unprecedented pace of economic development in the state of Georgia and because the Company has seen more increases in large projects interested in the state over the last several months than decreases. The P95 value establishes an upper limit for potential large load outcomes, offering a heightened level of load realization that is expected to benefit all customers and additional capacity resources to accommodate potential load increases in the ongoing economic development pipeline. Considering the uncertainty surrounding future growth, the Company opted for the P95 load value to ensure sufficient capacity to meet the anticipated loads and continue to support economic development in Georgia and to benefit all customers.

   Regarding the risk of over-supply, the Company consistently takes measures to sell any capacity above the target reserve margin in the wholesale market. For instance, the power purchase agreement ("PPA") with Mississippi Power Company has already been sold to another regional supplier for 2024 and 2025 since those years are prior to the Company's year of need as identified in the 2023 IRP Update.

b. Please refer to TS STF-DEA-1-5 Attachment A for the P50 forecast of economic development loads. Georgia Power has not created a P75 forecast of economic development loads; therefore, one cannot be provided.

c. Please refer to STF-DEA-1-5 Attachment B for the P50 load forecast and annual capacity balancing. A P75 load forecast and annual capacity balancing cannot be provided since Georgia Power did not create a P75 forecast of economic development loads.

Contact: Francisco Valle

DG/LM-2:
GPC Response to PD STF-JKA-2-22

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-2-22

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-2-22 ("Response"). In the Response, the Company has provided data supporting the economic analysis of projects proposed in the 2023 IRP Update including an acquisition with sensitive pricing and confidential details (the "Information"). All of such information constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives 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 its disclosure or use. Specifically, the Information includes competitively sensitive details specific to the resources under contract, proposed to be acquired or 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. In addition, the terms of the agreements themselves provides for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in current or future negotiations, as counterparties may use the Information as a bargaining tool in negotiations or fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-2-22

Question:

a. Please provide all documents that serve as the basis for the cost assumptions for the Yates CTs.

b. What is the primary fuel for Yates CTs? If gas, has the Company made arrangements to obtain firm gas transportation?

c. Explain why Yates can be modeled to use natural gas while the generic CTs are modeled using oil?

d. Please provide all assumptions regarding gas deliverability to Yates, including firm transportation costs, the need to construct natural gas pipeline capacity, etc.

e. Why does page 21 state that the CTs will add between 1,000 MW and 1,400 MWs of capacity. Why isn't this statement more definitive and when will the decision about that be made? If the Company had wanted, would the Yates site support the addition of a 4th CT addition?

f. If the CTs are approved in this case, how long after that would be required for the Company to construct the CTs.

Response:

a. Please see STF-JKA-2-19 for costs the Company has already incurred. The Company remains in active negotiations on the project. These negotiations and Southern Company's recent experience building new natural gas plants informed the cost estimates for the Yates CTs. As mentioned in the "Technical Information Supporting the Proposal to Develop up to 1,400 MW from Three Simple Cycle Combustion Turbines at Plant Yates," found in the Technical Appendix to the 2023 IRP Update filing, these costs estimates are subject to change prior to the execution of an Engineering, Procurement, and Construction ("EPC") agreement. As mentioned in the Technical Appendix the Company will update the Commission upon execution of a final EPC contract and request certification of Plant Yates Units 8-10 at that time.

b. Plant Yates Units 8-10 are dual fuel units. They can operate on natural gas as available, but they are unlikely to have reliable supply of natural gas during peak winter periods without firm transportation ("FT"). No FT has been procured for these units. Therefore, these units will be supplied with oil to support continued operation during peak conditions. These units will be able to utilize gas when FT is available from other units such as the Plant Yates steam units or when interruptible pipeline transportation is available.

c. The Company modeled Plant Yates Units 8-10 assuming oil dispatch costs for the winter months. For the non-winter months, the Company assumed availability of natural gas in its economic analysis production cost modeling, which is weather normalized. Plant Yates Units 6-7 have firm gas transportation that can be utilized for Plant Yates Units 8-10 if economic. Additionally, natural gas pipelines are generally less constrained during non-winter months. This may differ from generic repeatable combustion turbines ("CT") as the available of natural gas is highly location dependent and generic CTs do not have a specific location. Please see the Company's response to STF-JKA-2-14 subpart (e) for more information on the generic CT assumption.

d. Plant Yates Units 8-10 will primarily run on fuel oil during peak winter and summer periods when the pipeline is constrained. No FT or additional gas capacity is being proposed to support these units since these units can burn oil year around. It is being proposed to build a new pipeline lateral from Transco's mainline to the plant. The new lateral would be adjacent to the existing pipeline lateral to Plant Yates from Transco.

e. The range of output capacity was used to illustrate the variance between oil and gas fired operations. Active negotiations over **REDACTED** guaranteed capacity have informed this range. The guaranteed capacity will be finalized upon execution of the final EPC contract. A fourth combustion turbine has not been evaluated for the 2023 IRP Update but could be considered in the future.

f. Under the preliminary schedule as shown in Figure 2 of the Technical Appendix for the Yates CTs, construction of the first two units will be substantially completed in 32 months with the third unit under construction for 36 months assuming a final decision for the 2023 IRP Update is obtained in April 2024. The Company has already begun activities in advance of a final decision to preserve the current timeline. Information on these activities is further described in STF-JKA-2-19, which are necessary to support engineering and procurement of critical equipment in a timely manner.

DG/LM-3:

GPC Response to TS STF-PIA-7-15, TS Attachments A-P

Fully Redacted as it Contains Trade Secret Information

DG/LM-4:
GPC Response to TS STF-JKA-2-19, Attachment B

Fully Redacted as it Contains Trade Secret Information

DG/LM-5:
GPC Response to PD STF-JKA-6-5

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-6-5

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-6-5 ("Response"). In the Response, the Company has provided assumptions and information about proposed expansion projects used in the economic analysis of the resources proposed as part of the 2023 IRP Update. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives 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 its disclosure or use. Specifically, the Information contains competitively sensitive details regarding sites that are being proposed for new BESS projects. If revealed to the public, a generation wholesaler, power marketer, or original equipment manufacturer could use the Information to arbitrarily tailor proposals with the intention of pricing products and services according to the Company's expected costs, which could undermine the Company's ability to procure the best cost products and services for customers. Such disclosure could unfairly allow competitors to artificially manipulate the wholesale market and ultimately harm the Company. Lastly, the Company's competitors are generally not required to file similar forecast information and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-6-5

Question:

Regarding the Company's Request for Information Summary, Section 2.3, the Company states, "There is not enough time for an RFP to be conducted, resources to be constructed following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027."

a. Please explain if the Company could have considered an agreement outside of an RFP process, such as an unsolicited offer.
b. Please explain how the Company was able to negotiate the Santa Rosa PPA outside of an RFP, but did not consider negotiating an agreement for any of the RFI identified projects the same way.
c. Please explain how the Company was able to negotiate the Mississippi Power agreement outside of an RFP, but did not consider negotiating an agreement for any of the RFI identified projects the same way.
d. Please explain what transmission constraints are a barrier to the ESS projects identified in the RFI, but are not a barrier to the **REDACTED** Solar + BESS projects.

Response:

a. Yes, the Company could consider an agreement outside of a Request for Proposal ("RFP") process for the potential new or planned projects that responded to Georgia Power's Request for Information ("RFI"). However, the Company would need to solicit additional information, including pricing, from such projects and evaluate the generation and transmission costs and benefits for each response to determine which projects are viable, which projects are most cost-effective, and when the Company could receive delivery from each potential project. Any transmission upgrades required by new generation resources must be identified and constructed, which can take substantial time given the current long lead times on the procurement and supply of transmission equipment. Instead, as described in the Company's response to STF-PIA-4-16(d), the Company is currently focusing its efforts on identifying existing sites where battery energy storage systems ("BESS") can be deployed and deliver energy to the transmission system prior to November 2027.

b. The Santa Rosa Energy Center was a known, existing generation asset that was identified in July 2023 as a potential resource to meet the Company's 2023 IRP Update capacity needs. Given identification in July 2023 and the fact that it is an existing asset that can meet the Company's generation needs in the 2023 IRP Update without the construction of transmission projects, the Company was able to negotiate a power purchase agreement ("PPA") with Santa Rosa Energy Center, LLC, prior to filing the 2023 IRP Update on October 27, 2023. The Company issued its RFI in September 2023 to gather market

information regarding the availability of existing and planned capacity resources for years 2026-2031. The RFI closed on October 24, 2023 and confirmed that no existing capacity resources could help meet the Company's capacity needs being addressed in the 2023 IRP Update. For potential new or planned projects, the Company would need additional information, including pricing, from the respondents to determine viability, cost-effectiveness, and deliverability of each potential project. See the Company's response to part (a) for transmission considerations for potential new or planned projects.

c. The Mississippi Power PPA consists of known, existing generation assets and was identified in July 2023 as a potential resource to meet the Company's 2023 IRP Update capacity needs. Given identification in July 2023 and the fact that it contains existing assets that can meet the Company's generation needs in the 2023 IRP Update without the construction of transmission projects, the Company was able to negotiate a PPA with Mississippi Power prior to filing the 2023 IRP Update on October 27, 2023. The Company issued its RFI in September 2023 to gather market information regarding the availability of existing and planned capacity resources for years 2026-2031. The RFI closed on October 24, 2023 and confirmed that no existing capacity resources could help meet the Company's capacity needs being addressed in the 2023 IRP Update. For potential new or planned projects, the Company would need additional information, including pricing, from the respondents to determine viability, cost-effectiveness, and deliverability of each potential project. See the Company's response to part (a) for transmission considerations for potential new or planned projects.

d. The **REDACTED** BESS plus solar project utilizes existing transmission interconnection infrastructure, and the Company's transmission screening analyses indicate that the project can deliver up to 200 MW of energy to the transmission system through the summer of 2029. Once prior planned transmission projects are completed by the summer of 2029, the project could deliver up to 415 MW to the grid. For potential new or planned projects in the RFI, the Company would need additional information, including pricing, from the respondents to determine viability, cost-effectiveness, and deliverability of each potential project. See the Company's response to part (a) for transmission considerations for potential new or planned projects.

DG/LM-6:
GPC Response to PD STF-JKA-4-10

STF-JKA-4-10

Question:

Please refer to the paragraph on page 21, line 4, beginning with the statement: "The second driver, the decreased supply of electricity, is related to the limited amount of electric generation capacity available in the wholesale market."

a. Please provide all documentation that the Company used to support that statement, in addition to the Company's RFI referenced on page 22 of the testimony.

b. Please provide all workpapers the Company created associated with the RFI. Provide those electronically, with all formulae intact. For example, referring to the testimony on page 22, there were 44 submissions to the RFI. Please provide any summary available such as a table the Company created containing bid details that identify each submission by provider, provide the bid prices and terms offered, and indicate the reason(s) why the Company determined they were not viable options. If no table of this type, or a similar type was created, explain why not.

c. Provide copies of all bids received in the RFI.

d. See the Company's Supplemental Filing containing the review of the RFI. At pdf page 9, the Company noted there were 2 Qualifying Projects that were existing resources. At pdf page 11, the Company stated, "no existing resources were identified which could help meet the capacity needs being addressed in the Company's 2023 IRP." Why couldn't the 2 projects mentioned at pdf page 9 be acquired to help meet the capacity needs in the 2023 IRP?

e. The RFI Table 0-3-2 at pdf page 10 shows that 100 MW of capacity could be acquired for 2025, 1,110 in 2026, and 1,495 in 2027. Why didn't the Company perform a comparison to compete those options against the Santa Rosa PPAs, Yates CTs, Mississippi PPA, 1,000 MW of Company developed, owned, and operated BESS, the DER option, or the new demand response tariff that the Company has proposed to acquire, build, or establish in this IRP? If any analysis was performed please provide all workpapers and modeling analyses that were performed, electronically, with all formulae intact.

Response:

a. Based on the responses received to the Company's Request for Information ("RFI") issued in September 2023, there were no existing capacity resources available in the market to meet the need years addressed in this 2023 IRP Update. The Company's RFI is located in

Exhibit A of the RFI Summary that was filed as part of the Supplemental Filing made on December 4, 2023. Also, please reference the market activity referenced on page 15 of the 2023 IRP Update Main Document.

b. Please see the Company's response to STF-JKA-2-24. In addition, the Request for Information conducted was not a Request for Proposals; therefore, the submissions were not bids and pricing was not required or provided by all respondents.

c. Please see the Company's response to STF-JKA-2-24.

d. The two existing Qualifying Projects that submitted a response to the RFI are units that are (i) currently under contract with the Company and (ii) are subsequently not available during the need years addressed in this 2023 IRP Update.

e. The Company did not perform a detailed analysis on the potential projects identified in Table 2-3-2 in the RFI summary showing that 100 MW of capacity could be acquired for 2025, 1,110 in 2026, and 1,495 in 2027 because there was not adequate time to administer and conduct an RFP that provides for all bids to be properly evaluated, conduct transmission studies, and ultimately construct new assets or interconnection facilities to meet the capacity needs being addressed in the 2023 IRP Update. In addition, if provided, pricing information was optional and non-binding for participants responding to the RFI and interconnection and construction plans are not known, any of which could significantly impact a potential project's availability.

DG/LM-7:

GPC Response to PD STF-JKA-2-20

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-2-20

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-2-20 ("Response"). In the Response, the Company has provided information related to the strategy, provisions, and evaluation of the Mississippi Power power purchase agreement ("PPA"). All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives 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 its disclosure or use. Specifically, the Information contains competitively sensitive pricing and operational capability data, specific to the resources under contract within the PPA. 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. In addition, the terms of the PPA provide for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in current or future PPA negotiations, as counterparties may fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-2-20

Question:

Mississippi Power PPA

a. Why did the Company acquire the Mississippi Power resource as early as 2024 when there is no need for capacity that early?

b. Provide copies of any orders in which the Mississippi Commission required Mississippi Power to shut down resources or otherwise eliminate excess capacity that was ultimately relevant to the decision to enter into the PPA with Georgia Power.

c. Explain what issues will be addressed by the Operating Committee specifically related to the "day-to-day operating procedures".

d. Please explain all requirements for FERC approval and what the status of obtaining that approval is.

e. **REDACTED REDACTED**

f. **REDACTED REDACTED**

g. **REDACTED REDACTED**

h. See Table 1, Contract Capacity Price. Please provide all of the Company's workpapers that were used that led the Company to agree to the reasonableness of the prices in the table.

i. Please provide the workpapers that took the formulas associated with the Contract Capacity price and computed costs that were modeled in the TS Economic Analysis of Capacity Resources.xlsx analysis.

Response:

a. The term of the Mississippi Power Company ("Mississippi Power") power purchase agreement ("PPA") begins January 1, 2024, because Mississippi Power was ordered to retire approximately 950 MW of capacity by the end of 2027 or show with detailed evidence why continued operation of the resources is in the best interests of its customers. Therefore, Mississippi Power planned to retire some of that capacity by the end of 2023 and was actively remarketing the remaining capacity to be sold outside of the Southern Company system. Had Georgia Power not executed the PPA for the full five years, the proposed resource very likely would not have been available for the last three years when the Company has a capacity need. By purchasing 750 MW from Mississippi Power through this PPA, Georgia Power ensures that this resource not only remains in the Southern Company pool but also provides dedicated, reliable, market-priced capacity and energy to Georgia Power's customers to meet its burgeoning short-term demand.

   For the benefit of customers, Southern Wholesale Energy ("SWE"), on behalf of Georgia Power, will attempt to remarket capacity for the years prior to the winter of 2025/2026. The Company has already contracted for the sale of 500 MW to a regional electrical service provider for January 1, 2024, through September 30, 2025, thereby recovering costs from a third party in a period before the capacity is needed to serve Georgia Power retail customers.

b. Please see STF-JKA-2-20 Attachment for the applicable order from Mississippi Public Service Commission in Docket No. 2018-AD-145.

c. Since both Georgia Power and Mississippi Power are members of the Southern Company Pool, which adheres to Southern Dispatch practices and the Intercompany Interchange Contract ("IIC"), "day-to-day operating procedures" will not be necessary. If the affiliate or pool relationship were to change during the term of the PPA, the Operating Committee would have responsibility for developing any subsequently needed operating procedures.

d. This PPA is executed under Southern Operating Companies' Market Based Rate Tariff ("MBR") with Mississippi Power as an electric utility operating company engaged in the sale of electric power at wholesale that has received authorization from the Federal Energy Regulatory Commission ("FERC") to provide wholesale power supply services at market-based rates. Transactions made under MBR do not require separate filings at FERC for approval. Further, Georgia Power is an electric utility operating company which provides retail electric service to end-use customers in its franchise service territory in the state of Georgia that is authorized to purchase wholesale power supply services.

e. As discussed in the response to subparts (a) and (b) above, purchasing 750 MW that can be met by any resources available to Mississippi Power prevented this capacity from being

removed from the Southern Company pool where it would no longer be available through system reserve sharing to serve Georgia Power customers. The Mississippi Power PPA was set up to be similar to system reserve sharing as allowed under the IIC, which is based on total capacity available from each Operating Company. Mississippi Power will continue to evaluate any necessary actions associated with the Mississippi Public Service Commission order in Docket No. 2018-AD-145.

f. As defined in the Power Supply Service Schedule, "seller generating resources" are, at any given time, the electric generating units owned or controlled by Mississippi Power that are in commercial operation and are submitted to Southern Dispatch. The PPA obligations can be met by any resources available to Mississippi Power.

g. Georgia Power and Mississippi Power both operate as part of the Southern Company system pool, and the expectation is that the conditions in Section 4.2 of the Power Supply Service Schedule would potentially occur under emergency situations, such as winter weather events, where the Southern Company system is impacted. Mississippi Power has every incentive for high levels of unit performance under the Southern Company system and its obligation to provide reliable service to its customers through the Southern Company system pool. No other data was acquired from Mississippi Power or Southern Company to evaluate the inclusion of this provision in the Mississippi Power PPA.

h. Please see the "9 TS Economic Analysis" folder in the Technical Appendix to the 2023 IRP Update for an economic assessment of the Mississippi Power PPA. This resource is available to meet near-term capacity needs. The results of the economic analysis demonstrate this PPA is competitive with other options. Furthermore, the capacity prices listed in Table 1 reflect the market price of capacity and are consistent with other recently executed contracts, such as TS STF-JKA-2-19 Attachment B. Finally, the 2024 reserve sharing rate as prescribed in the IIC and filed with FERC as part of the informational filing is $73.20/kw-year which is within REDACTED of the annualized rate in Table 1.

i. Please see the "TS Economic Analysis of Capacity Resources.xlsx" file in the "9 TS Technical Appendix Economic Analysis" folder of the "TS Technical Appendix," which was previously provided to the Commission Staff on October 27, 2023, in the 2023 IRP Update filing. The formulas associated with the contract capacity price and computed costs are on the "Cost Inputs" worksheet.

DG/LM-8:

GPC Response to STF-JKA-4-19

Redacted as it Contains Trade Secret Information

DG/LM-9:
GPC Response to PD STF-JKA-6-7

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-6-7

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-6-7 ("Response"). In the Response, the Company has provided capacity need information for the Southern Company System. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives 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 its disclosure or use. Specifically, the Information contains competitively sensitive details on the capacity balance of the Southern Company System. If the Information was revealed to the public, a generation wholesaler, other public utility, or power marketer could use the Information to tailor purchased power offerings that could undermine the Company's market position. This could artificially drive up purchased power prices that would cost the Company and its customers more than had the Information been kept confidential. Publicly disclosing this Information could potentially harm customers by not allowing the Company to procure the best cost resources for customers. This Information also contains specific affiliate operating company details. Publicly disclosing these details could provide competitors with a competitive advantage over the affiliate operating companies to their detriment and the Company's detriment. Also, as a participant in the wholesale market through its affiliate Southern Wholesale Energy ("SWE"), disclosing the amount of generation available for sale in the market could impact the Company's market position. Finally, the Company's competitors are not required to disclose this type of information and to require the Company to do so would place it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-6-7

Question:

Refer to the Company's 2023 IRP Testimony on pages 33 and 35 that discusses the remarketing of Santa Rosa and the Mississippi Power capacity prior to Georgia Power's year of need. The Company noted that it is requesting regulatory asset treatment of its costs.

a. Please explain if the Company included this impact in the economic evaluation presented for the Santa Rosa project. If not, why not? If so, where?

b. Please explain who the counterparty is for the Mississippi Power sale, and provide a discussion of the terms and conditions of the sale. Please provide a copy of the agreements reached.

c. Please provide a narrative update as to the status of the Santa Rosa sale and whether a counterparty has been identified and terms reached. Please provide a copy of the agreements reached.

d. Please confirm that the terms of the Santa Rosa contract spans January 2024 through December 2028, and that the Southern Company system doesn't have a need until REDACTED **REDACTED**.

e. Please explain if GPC could have obtained capacity through the IIC from Southern Company in the **REDACTED** period, and that the Santa Rosa contract is only serving a resource need for the system in **REDACTED**.

Response:

a. The Company's economic evaluation includes the benefits of remarketed capacity associated with the Mississippi Power Company Power Purchase Agreement ("PPA") based on an already executed sale of capacity and energy to another regional electrical service provider. The Company did not assume this benefit for the Santa Rosa PPA in the economic evaluation as there is no executed contract currently in place. If additional capacity is remarketed from the Santa Rosa PPA, this would improve the economics of the Santa Rosa PPA assuming no other changes and remarketed capacity remains before the year of need. The Company did not explicitly reflect the regulatory asset treatment of its costs in the economic evaluation. However, the Company did consider the annual revenue requirement impact of the regulatory asset in its assessment of net impact to customers. Please see the Company's response to STF-DEA-3-6 for this information.

b. Please see the Company's response to STF-JKA-4-19(b) for the requested information.

c. Please see the Company's response to STF-JKA-4-19(e) for the requested information.

d. The term of the Santa Rosa PPA, if approved by the Commission, begins on the first day of the month following Commission issuance of a certificate of public necessity and convenience for the PPA. If approved in accordance with the procedural and scheduling order of the 2023 IRP Update, the Santa Rosa PPA would become effective on May 1, 2024, and continue through December 31, 2028.

   The Southern Company System is projected to have a capacity need by the winter of **REDACTED**. The Intercompany Interchange Contract ("IIC") for the Southern Company System provides for coordinated planning between the Operating Companies and for the sharing of temporary surpluses and deficits of capacity. While the IIC affords participants the ability to rely on temporary surplus capacity on the System, each Operating Company is responsible for and expected to have adequate resources, including an appropriate level of reserves, to reliably serve its own load obligations. Any retail Operating Company that has excess reserves may decide at any point to retire some of the capacity or make wholesale sales predicated on some or all of that capacity provided that such Operating Company is maintaining adequate resources to reliably serve its own obligations. In either case (resource retirement or wholesale sale), the effect would be a reduction in the level of available capacity reserves on the System. Additionally, the other retail Operating Companies may experience increased economic development activity similar to what the Company is experiencing and may decide to not make their surpluses available to the Company while the economic development activity is being assessed.

e. See the Company's response to part (d). Projected surplus capacity on the System is not guaranteed to be available to serve Georgia Power's retail customers. The Santa Rosa PPA helps meet Georgia Power's capacity needs for 2026-2028. For the benefit of customers, Southern Wholesale Energy, on behalf of Georgia Power, is attempting to remarket capacity associated with the Santa Rosa PPA for 2024-2025.

DG/LM-10:
GPC Response to TS STF-PIA-10-3

Fully Redacted as it Contains
Trade Secret Information

DG/LM-11:

GPC Supplemental Response to STF-JKA-2-2

STF-JKA-2-2

Question:

Refer to the Load and Resource Balance presented in "TS 2023 IRP Update Models and Workpapers.zip\Main Document\Figures 4, 5, 6, & 9 - Capacity Needs Data for B22, B23, and 2023 IRP Update.xlsx"

a. Explain the change in capacity values for Bowen 1-2, 3-4, and Scherer 3, as the capacity values of those units appear to be different than what was assumed in the 2022 IRP.
b. Explain the decrease in assumed DSO capacity, as the capacity value for DSO resources appears to be different than what was assumed in the 2022 IRP. Also, please explain any change in assumptions such as customer participation since the 2022 IRP.
c. What capacity equivalence (ICE, ELCC, etc.) factors are assumed for new and existing resources in the Company's load and resource balance as presented? Also, importantly, provide a view of the "2023 IRP Update w Extensions" tab but with nameplate capacity ratings for winter for each resource.
d. What capacity equivalence (ICE, ELCC, etc.) factors are assumed for the proposed capacity resources evaluated in "TS Economic Analysis of Capacity Resources?" Provide such capacity equivalence factors for every unit.
e. What capacity equivalence (ICE, ELCC, etc) factors are assumed for the proposed resources in the GenMix Study? Provide such capacity equivalence factors for every unit.
f. Has the Company generated a load and resource balance view with the proposed capacity resources included associated with "TS Economic Analysis of Capacity Resources"? If not, why not? Please provide such a view if it is available.
g. Has the Company generated a load and resource balance view with the proposed capacity resources included associated with each GenMix case? If not, why not? Please provide such a view if it is available.
h. Please provide the Company's assumptions for capacity additions (technology, collocated with or without BESS, baseload/intermediate/peaking, MW target factors to adjust the solicitation target amounts by the expected procurement amounts, etc.) that are planned to be procured through RFPs that were approved in the Company's 2022 IRP.

Response:

a. The winter capacity values for Plant Bowen Units 1-4 and Plant Scherer Unit 3 increased due to additional demonstrated winter peaking capacity.

b. The Demand Side Option ("DSO") capacity resources are updated annually to reflect the best available information on program participation and Economic Load Carrying Capability ("ELCC"). The decrease in planning capacity between the 2022 IRP and the 2023 IRP Update is primarily driven by a change in the ELCC for the Demand Plus Energy Credit ("DPEC") program. Updated ELCC values reflect modeling of program parameters (resource availability, call limits, call conditions, required notice) and recently observed response rates.

c. Please see STF-JKA-2-2 Attachment A.

d. Please see TS STF-JKA-1-4 Attachment columns H and I for the annual capacity contribution for each resource in the economic analysis.

e. The MPC PPA was the only proposed resource explicitly modeled in the Resource Mix Study, and it was assumed to have an ELCC of 100%.

f. Please see STF-JKA-2-2 Attachment B. The Company did not include the potential option to acquire an additional ownership interest in an existing generating asset within the Southern Company footprint because the parties were unable to reach agreement at this time, as described in the Company's Direct Testimony filed on December 4, 2023.

January 12, 2024 Supplemental Filing Update: Please see STF-JKA-2-2 Supplemental Attachment B for the Company's latest projected capacity needs including the 2023 IRP Update proposed resources. In accordance with the Agreement for Engineering, Procurement, and Construction between Georgia Power Company and a consortium of Mitsubishi Power Americas, Inc. and Black & Veatch Construction, Inc., with an effective date of January 12, 2024, and provided as TS STF-JKA-2-19 Supplemental Attachment P, Georgia Power reflects the latest construction schedule for the proposed Plant Yates combustion turbines ("CTs"). Due to one of the proposed CTs expecting to achieve commercial operation in 2027, rather than 2026, approximately 200 MW of Other BESS were advanced to 2026 to fulfill the resulting projected capacity need for the winter of 2026/2027. Furthermore, the Company updated the Santa Rosa PPA firm capacity based on the results of a Southern Company Native Load Reservation interface study report for the Santa Rosa PPA resource. While annual firm transmission cannot be confirmed for 2024 through May 2026, Georgia Power is pursuing and may obtain short-term firm transmission for the resource during this period. Consistent with the transmission screening

analyses in the 2023 IRP Update, no transmission project costs are attributable to the Santa Rosa PPA.

g. Please see STF-JKA-2-2 Attachment C for the load and resource balance views that include the generic expansion resources for each planning scenario from the Resource Mix Study associated with the Errata to the 2023 IRP Update Supplemental Filing that was filed on December 7, 2023. The Mississippi Power Company ("MPC") power purchase agreement ("PPA") was the only proposed resource explicitly modeled in the Resource Mix Study. The MPC PPA is immediately available, without construction delay or transmission restrictions, and represents a supply-side resource of extraordinary advantage. Additionally, the MPC PPA negotiations were near finalized at the time modeling began for the 2023 IRP Update, and the MPC resources are already included in the model, which simplified capturing the MPC PPA. Therefore, the MPC PPA was represented in the Resource Mix Study analysis.

h. Please see STF-JKA-2-2 Attachment D for the Company's assumptions for capacity values for additions that are planned to be procured through requests for proposals ("RFPs") that were approved in the Company's 2022 IRP. The target procurement amounts can be found in Column E. The Company does not model or assume the results of future RFPs to be conducted to meet the Company's capacity needs for certain periods, such as the 2029-2031 All-Source RFP.

DG/LM-12:
GPC Response to TS STF-DEA-3-6,
Attachment G

Fully Redacted as it Contains
Trade Secret Information

DG/LM-13:

GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G

Fully Redacted as it Contains Trade Secret Information

DG/LM-14:
GPC Response to STF-JKA-2-14

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-2-14

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-2-14 ("Response"). In the Response, the Company has provided cost and performance criteria for a variety of resource planning technologies. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives 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 its disclosure or use. Specifically, the Information contains competitively sensitive details on the costs of carbon capture equipment as well as cost and performance criteria for generic generating resources included in the resource plan. Publicly disclosing these costs would allow bidders in future solicitations to tailor their proposals and potentially set an artificial floor on bidding, which would harm customers by not allowing the Company to conduct a proper solicitation and obtain the best cost estimates for future consulting work.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-2-14

Question:

See Candidate Expansion Unit Section 2.6.1

a. Please provide all reports, analysis, studies, etc., that supports the fact that Georgia Power could capture 90% of CO2 emissions.
b. Provide all reports showing where Georgia Power could possibly store 90% of the CO2 emissions from CC resources.
c. Explain why Georgia Power did not assume that CC units would operate on hydrogen instead of assuming that those CC resources would store 90% of the CO2 emissions.
d. Please provide a copy of any comments that Southern Company or Georgia Power filed on August 8th or later in response to the EPA's request for comments in review of the EPA Section 111 proposed rule.
e. Please explain why the Company chose to use the assumption that CTs "are assumed to operate with oil as a primary fuel source." Why not natural gas and what assumption was used for the secondary fuel source given that the CTs were assumed to be Dual-fuel CTs?
f. Explain what assumptions have changed associated with the following resources between the 2022 IRP and the 2023 IRP. This should include capacity, costs, modeling limits, etc.

    i. Solar
    ii. Battery Storage
    iii. Wind
    iv. CTs
    v. CCs
    vi. Nuclear

g. Explain why the Mississippi Power PPA was included as a resource option, and none of the other PPAs such as Santa Rosa, etc. were included as resource options.

Response:

a. Please see TS STF-JKA-2-14 Attachment A for details on the generic carbon capture equipment assumption included in the Resource Mix Study.

b. Please see STF-JKA-2-14 Attachment B for details on storage viability in the United States. STF-JKA-2-14 Attachment B is a Department of Energy/National Energy Technology Laboratory report on sequestration viability in the United States that details a large amount of storage capacity available in the southeast as well as ongoing projects in the region to characterize that storage.

c. Production and transport of low greenhouse gas hydrogen is currently not demonstrated to the scale required to qualitatively satisfy the requirements of multiple retrofit or expansion

resources operating at an 85% capacity factor assumption used for the generic combined cycle expansion units.

d. See STF-JKA-2-14 Attachment C for the Company's comments on the EPA section 111 proposed rule for Electric Generating Units.

e. The Company assumed oil dispatch for new generic combustion turbines ("CTs") because the pipelines serving the Company region have become increasingly constrained and less flexible in recent years. These constraints limit the amount of swing and daily imbalance through frequent issuance of daily Operational Flow Orders (i.e., curtailment of gas supply). These constraints bind the Southern Company retail operating companies' ability to operate any of its natural gas units on the same pipeline system, including new CTs. The Company can successfully manage this through the usage of fuel oil. Additionally, the ability to construct new pipeline infrastructure to alleviate pipeline constraints has been very challenging (e.g., Mountain Valley Pipeline). Therefore, assuming new pipeline infrastructure will be available for all future natural gas units is unrealistic. Given the current operational realities and the challenges facing the pipeline infrastructure industry, the Company assumes the most reliable operational plan for new generic expansion CTs is for them to be dual-fueled with the ability to burn fuel oil year-round and plan to be augmented with natural gas when it is available. The availability of firm natural gas supply is highly location dependent. Therefore, the Company will evaluate the applicability of firm transportation on a case-by-case basis as specific resource decisions are identified.

f. See TS STF-JKA-2-14 Attachment D for details on year-to-year changes in the requested technologies.

g. The Mississippi Power Company power purchase agreement ("MPC PPA") was the only proposed resource allowed to be selected in the Resource Mix Study. The MPC PPA negotiations were near final when the modeling was being conducted, and the Mississippi Power Company resources are already included in the model, making it easy to implement this assumption. The other proposed resources will be included in future modeling if approved in this docket.

DG/LM-15:
GPC Response to STF-JKA-3-10

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-3-10

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-3-10 ("Response"). In the Response, the Company has provided various assumptions used in the economic analysis of the resources proposed as part of the 2023 IRP Update. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives 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 Information includes detailed information regarding the Company's forecasted prices and fuel assumptions. Disclosure of the Information would provide extensive insight into the Company's projected unit operations. If revealed to the public, a generation wholesaler, power marketer, or original equipment manufacturer could use the Information to arbitrarily tailor proposals with the intention of pricing products and services according to the Company's expected costs, which could undermine the Company's ability to procure the best cost products and services for customers. Such disclosure could unfairly allow competitors to artificially manipulate the wholesale market and ultimately harm the Company. Lastly, the Company's competitors are generally not required to file similar forecast information and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-3-10

Question:

It appears that in the B2023 Aurora database (B2023_Final_GPC_IRP_update.apz), the Yates CT 8-10 units are mapped to a fuel price proxy "Yates CT 8-10_Marginal_Fuel_B23_MG0_DEPS_202209". Please provide a B2024 database fuel price proxy that can be used as a fuel price proxy assumption for the Santa Rosa contract.

Response:

The Company assumes the last sentence in the question was simply a copy and paste error. Therefore, the Company assumes the question is seeking the fuel price proxy assumption for Plant Yates Units 8-10 and not Santa Rosa as requested in STF-JKA-3-9.

The "Yates CT 8-10_Marginal_Fuel_B23_MG0_DEPS_202209" fuel price proxy was created using a combination of Wilson Unit 1A oil prices in winter months (January, February, December) and Yates Units 6-7 gas prices in non-winter months. The B2024 fuel price proxies needed to recreate Plant Yates Units 8-10 oil/gas fuel prices are identified below:

- mn_Wilson 1A_Marginal_Fuel_B24_MG0_DEPS_202309_v2 (January, February, December)
- mn_Yates 6_Marginal_Fuel_B24_MG0_DEPS_202309_v2 (March – November)

For convenience, Plant Yates Units 8-10 B2024 oil/gas prices are provided in TS STF-JKA-3-10 Attachment.

Contact: Mike Bush

DG/LM-16:
GPC Response to STF-JKA-2-2, Attachment C

Georgia Power Territorial Base Case Load vs. Existing Capability MG0 with Generic Expansion Resources (2023 IRP Update - Winter)

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Peak Demand (MW), (A)	15,283	15,947	17,256	18,928	19,751	20,551	21,326	21,880	22,141	22,353	22,515	22,630	22,746	22,938	23,257	23,624	23,926	24,282	24,643	25,033
Owned Generating Capacity (MW), (B)	14,770	15,341	15,343	15,706	15,706	14,702	14,703	14,703	14,703	14,703	14,703	14,013	10,453	10,453	10,494	10,494	10,494	10,494	10,494	10,494
Purchased Generating Capacity (MW), (C)	4,535	5,159	5,237	5,321	5,576	5,905	5,905	3,886	3,924	3,906	3,940	2,661	2,063	2,023	1,681	1,681	1,321	1,301	1,298	1,295
Dispatchable DSOs (MW), (D)	675	696	716	758	805	750	752	750	749	749	749	749	749	749	749	749	749	749	749	749
MG0 Generic Expansion Plan Resource Capacity (MW)	-	-	-	1,650	2,730	4,317	5,217	7,917	8,217	8,480	8,732	10,952	15,137	15,420	16,160	16,685	17,805	18,102	18,207	18,702
Total Capacity (MW)	19,980	21,196	21,296	23,435	24,818	25,674	26,577	27,256	27,593	27,838	28,124	28,375	28,401	28,645	29,083	29,608	30,369	30,646	30,748	31,240
Capacity Required to Meet GPC Target (MW) (E)	(964)	(1,352)	175	225	(129)	15	82	95	84	104	21	(86)	32	29	(11)	(77)	(460)	(292)	57	52
GPC Reserve Margin (%)	30.7%	32.9%	23.4%	23.8%	25.7%	24.9%	24.6%	24.6%	24.6%	24.5%	24.9%	25.4%	24.9%	24.9%	25.1%	25.3%	26.9%	26.2%	24.8%	24.8%

Notes

(A) Territorial Load requirements less non-dispatchable DSOs

(B) Assumes in-service dates of 7/31/2023 and 4/1/2024, respectively, for Plant Vogtle Units 3 & 4

(C) Includes territorial and imported power purchases.

(D) Values stated in combustion turbine equivalence terms

(E) Does not consider planning reserve sharing. GPC's small capacity need is met by System surplus. Reflects GPC's Target Reserve Margin resulting from a System Target Reserve Margin of 25.50% (2024-2026) and 26% (2027 and beyond).

Existing Capability

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Owned Generating Capacity (MW)	**14,770**	**15,341**	**15,343**	**15,706**	**15,706**	**14,702**	**14,703**	**14,703**	**14,703**	**14,703**	**14,703**	**14,013**	**10,453**	**10,453**	**10,494**	**10,494**	**10,494**	**10,494**	**10,494**	**10,494**
Nuclear	**2,468**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**
HATCH 1	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439
HATCH 2	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
VOGTLE 1	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539
VOGTLE 2	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540
VOGTLE 3	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509
VOGTLE 4	-	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509
Coal	**4,102**	**4,102**	**4,102**	**4,102**	**4,102**	**3,560**	**3,560**	**3,560**	**3,560**	**3,560**	**3,560**	**3,560**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
BOWEN 1	780	780	780	780	780	780	780	780	780	780	780	780	-	-	-	-	-	-	-	-
BOWEN 2	758	758	758	758	758	758	758	758	758	758	758	758	-	-	-	-	-	-	-	-
BOWEN 3	934	934	934	934	934	934	934	934	934	934	934	934	-	-	-	-	-	-	-	-
BOWEN 4	944	944	944	944	944	944	944	944	944	944	944	944	-	-	-	-	-	-	-	-
SCHERER 1	72	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-
SCHERER 2	72	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-
SCHERER 3	541	541	541	541	541	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle	**4,150**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**
MCDONOUGH 4	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945
MCDONOUGH 5	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934
MCDONOUGH 6	894	926	926	926	926	926	926	926	926	926	926	926	926	926	926	926	926	926	926	926
MCINTOSH 10	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692
MCINTOSH 11	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Oil/Gas Steam	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**648**	**648**	**648**	**648**	**648**	**648**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
GASTON 1 GAS	127	127	127	127	127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GASTON 2 GAS	128	128	128	128	128	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GASTON 3 GAS	102	102	102	102	102	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GASTON 4 GAS	103	103	103	103	103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
YATES 6 GAS	323	323	323	323	323	323	323	323	323	323	323	-	-	-	-	-	-	-	-	-
YATES 7 GAS	326	326	326	326	326	326	326	326	326	326	326	-	-	-	-	-	-	-	-	-
Combustion Turbine	**1,880**	**1,880**	**1,880**	**1,880**	**1,880**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**
BOULEVARD 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GASTON A	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MCDONOUGH 3A	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCDONOUGH 3B	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCINTOSH 1A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 2A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 3A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 4A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 5A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 6A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 7A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 8A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCMANUS 3A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
MCMANUS 3B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
MCMANUS 3C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
MCMANUS 4A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
MCMANUS 4B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
MCMANUS 4C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
MCMANUS 4D	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
MCMANUS 4E	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
MCMANUS 4F	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
MCMANUS DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 5A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WARNER ROBINS 1	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93

	WARNER ROBINS 2	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WILSON 1A	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
	WILSON 1B	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
	WILSON 1C	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON 1D	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	WILSON 1E	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON 1F	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	WILSON DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pump Storage		**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**
	ROCKY MTN 1 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 2 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 3 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	WALLACE DAM 1 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 2 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 5 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 6 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Hydro		**661**	**691**	**691**	**691**	**691**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**
	BARTLETT'S FERRY 1 HY	-	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 4 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	BARTLETT'S FERRY 5 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BARTLETT'S FERRY 6 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BURTON 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	BURTON 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	ESTATOAH 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FLINT RIVER 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINT RIVER 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINT RIVER 3 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	GOAT ROCK 3 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOAT ROCK 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOAT ROCK 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOAT ROCK 6 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOAT ROCK 7 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	GOAT ROCK 8 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	LANGDALE 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LANGDALE 6 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LLOYD SHOALS 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 3 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 4 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 5 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 6 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	MORGAN FALLS 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 3 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 5 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 6 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 7 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	NACOOCHEE 1 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NACOOCHEE 2 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NORTH HIGHLANDS 1 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 2 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 3 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 4 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	OLIVER 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 4 HY	-	-	-	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	RIVERVIEW 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	RIVERVIEW 2 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SINCLAIR 1 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	SINCLAIR 2 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	TALLULAH 1 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 2 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 3 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 4 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 5 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 6 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TERRORA 1 HY	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	TERRORA 2 HY	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	TUGALO 1 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	TUGALO 2 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	TUGALO 3 HY	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	TUGALO 4 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	WALLACE DAM 3 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
	WALLACE DAM 4 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
	YONAH 1 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	YONAH 2 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	YONAH 3 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Solar		**50**	**50**	**50**	**50**	**50**	**50**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**
	COMMUNITY SOLAR - COMER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	COMMUNITY SOLAR - GUYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	COMMUNITY SOLAR - WAYNESBORO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	FALCONS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	FORT BENNING	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	FORT GORDON	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	FORT STEWART SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	FORT VALLEY STATE UNIVERSITY	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	KINGS BAY SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	MCLB	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	MOODY AFB	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	RIGHT OF WAY SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ROBINS AFB	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	UGA SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	Unassigned Self-Build Solar	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1
System Sales		**(52)**	**(52)**	**(50)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(41)**	**(41)**	**(41)**	**0**	**0**	**0**	**0**	**0**	**0**
	SYSTEM SALE	(52)	(52)	(50)	0	0	0	0	0	0	0	0	(41)	(41)	(41)	0	0	0	0	0	0
Purchased Generating Capacity (MW)		**4,535**	**5,159**	**5,237**	**5,321**	**5,576**	**5,905**	**5,905**	**3,886**	**3,924**	**3,906**	**3,940**	**2,661**	**2,063**	**2,023**	**1,681**	**1,681**	**1,321**	**1,301**	**1,298**	**1,295**
	2019 IRP RENEWABLES - DG S2230	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2019 IRP RENEWABLES - DG S2330	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	2019 IRP RENEWABLES - DG W2330	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	2019 IRP RENEWABLES - DG W2430	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	2022 IRP Biomass	-	-	-	-	-	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
	2022 IRP ESS RFP	-	-	-	-	-	475	475	475	475	475	475	475	475	475	475	475	475	475	475	475
	2022 IRP SOLAR D	-	-	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35	35
	2022 IRP SOLAR DG RFP 1	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	2022 IRP SOLAR DG RFP 2	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	2022 IRP SOLAR E	-	-	-	-	-	-	-	-	38	38	38	38	38	38	38	38	38	38	38	38
	2022 IRP SOLAR F	-	-	-	-	-	-	-	-	-	38	38	38	38	38	38	38	38	38	38	38
	2022 IRP SOLAR G	-	-	-	-	-	-	-	-	-	-	38	38	38	38	38	38	38	38	38	38
	2022 IRP SOLAR H	-	-	-	-	-	-	-	-	-	-	-	38	38	38	38	38	38	38	38	38
	2022 IRP SOLAR US RFP 1	-	-	-	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
	2022 IRP SOLAR US RFP 2	-	-	-	-	-	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
	2022/2023 US - FLINT RIVER SOLAR	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	2022/2023 US - TIMBERLAND SOLAR	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	2022/2023 US - WADLEY SOLAR	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	2022/2023 US - WASHINGTON COUNTY SOLAR	-	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	ADDISON 1 (WEST GA)	177	177	177	177	177	177	177	-	-	-	-	-	-	-	-	-	-	-	-	-
	ADDISON 3 (WEST GA)	175	175	175	175	175	175	175	-	-	-	-	-	-	-	-	-	-	-	-	-
	ALBANY RENEWABLE ENERGY	50	50	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG S1320	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG S1420	2	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG S1520	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG S1620	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG W1420	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG W1520	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG W1620	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 1: DUBLIN SOLAR CENTER - DUBLIN	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 1: RICHLAND SOLAR CENTER	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 1: RINCON SOLAR CENTER	4	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 2: BUTLER SOLAR FARM	4	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 2: DECATUR COUNTY SOLAR PROJECT	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 2: HECATE ENERGY - OLD MIDVILLE RD LLC	5	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 2: SOLAR GLYNN	4	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-
	ASI PRIME 525 MW - DG S1625	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
	ASI PRIME 525 MW - DG S1635	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ASI PRIME 525 MW - DG S1725	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-
	ASI PRIME 525 MW - DG S1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	ASI PRIME 525 MW - DG S1735	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	ASI PRIME 525 MW - DG S1815	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-
	ASI PRIME 525 MW - DG S1820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
	ASI PRIME 525 MW - DG S1825	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ASI PRIME 525 MW - DG S1835	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ASI PRIME 525 MW - DG W1725	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-
	ASI PRIME 525 MW - DG W1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	ASI PRIME 525 MW - DG W1735	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ASI PRIME 525 MW - DG W1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-
	ASI PRIME 525 MW - DG W1820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-
	ASI PRIME 525 MW - DG W1825	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-
	ASI PRIME 525 MW - DG W1830	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	ASI PRIME 525 MW - DG W1835	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	ASI PRIME 525 MW - US 1: BUTLER SOLAR	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
	ASI PRIME 525 MW - US 1: DECATUR PARKWAY SOLAR PROJECT	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	-	-	-
	ASI PRIME 525 MW - US 1: PAWPAW SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	ASI PRIME 525 MW - US 2: LIVE OAK SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	ASI PRIME 525 MW - US 2: WHITE OAK SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	ASI PRIME 525 MW - US 2: WHITE PINE SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	AXIUM US SOLAR HOLDINGS (SD&D)	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BLUE CANYON	82	82	82	82	82	82	82	82	82	82	82	82	-	-	-	-	-	-	-	-
	CCSP DG - ONLINE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CCSP DG - REMAINING	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	COCA-COLA	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
	CONYERS RENEWABLE ENERGY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-
	DAHLBERG 1	-	-	-	-	85	85	85	85	85	85	85	85	85	-	-	-	-	-	-	-
	DAHLBERG 10	89	89	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-
	DAHLBERG 2	89	89	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-
	DAHLBERG 3	-	-	-	-	85	85	85	85	85	85	85	85	85	85	-	-	-	-	-	-
	DAHLBERG 4	89	89	89	89	89	89	89	-	-	-	-	-	-	-	-	-	-	-	-	-
	DAHLBERG 5	-	-	-	-	85	85	85	85	85	85	85	85	85	85	-	-	-	-	-	-
	DAHLBERG 6	89	89	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-
	DAHLBERG 8	89	89	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-
	DAHLBERG 9	-	-	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-
	EXELON HEARD 1	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	EXELON HEARD 2	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	EXELON HEARD 3	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	EXELON HEARD 4	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	EXELON HEARD 5	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	EXELON HEARD 6	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	GEORGIA RENEWABLE POWER FRANKLIN LLC	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
	GEORGIA RENEWABLE POWER MADISON	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
	GREEN POWER SOLUTIONS	29	29	29	29	29	29	29	29	29	29	29	29	-	-	-	-	-	-	-	-
	HARRIS 1	668	668	668	668	668	668	668	-	-	-	-	-	-	-	-	-	-	-	-	-
	HARRIS 2	-	690	690	690	690	690	690	690	690	690	690	-	-	-	-	-	-	-	-	-
	INTERNATIONAL PAPER - FLINT RIVER	25	25	25	25	25	25	25	25	25	25	25	25	-	-	-	-	-	-	-	-
	INTERNATIONAL PAPER - PORT WENTWORTH	28	28	28	28	28	28	28	28	28	28	28	28	28	28	-	-	-	-	-	-
	LSS 50 MW - HSH PEMBROOKE	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
	LSS 50 MW - SIMON SOLAR FARM	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
	LSS 50 MW - SOLAR D&D CAMILLA	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-
	LSS 50 MW - SOLAR D&D CAMP (MERIWETHER COUNTY)	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-
	MAS GEORGIA LFG - OAK GROVE	6	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-

	MAS GEORGIA LFG - PINE RIDGE	6	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-
	MAS GEORGIA LFG - RICHLAND CREEK	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-	-	-	-	-	-
	MID-GEORGIA COGEN	300	300	300	300	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MONROE POWER	309	360	360	360	360	360	360	360	360	360	360	360	360	360	360	360	360	-	-	-	-	-
	PIEDMONT GREEN POWER	55	55	55	55	55	55	55	55	55	-	-	-	-	-	-	-	-	-	-	-	-	-
	REDI 1400 MW - C&I: DOUGHERTY COUNTY SOLAR	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	REDI 1400 MW - C&I: TANGLEWOOD SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	REDI 1400 MW - DG CS S1920	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
	REDI 1400 MW - DG CS S1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	REDI 1400 MW - DG CS S1930	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	REDI 1400 MW - DG CS S1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	REDI 1400 MW - DG CS W1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	REDI 1400 MW - DG CS W1930	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	REDI 1400 MW - DG CS W1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	REDI 1400 MW - DG S2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	REDI 1400 MW - DG S2035	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	REDI 1400 MW - DG W2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	REDI 1400 MW - DG W2035	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	REDI 1400 MW - US 1: QUITMAN SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	REDI 1400 MW - US 1: SOUTHERN OAK SOLAR	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
	REDI 1400 MW - US 1: TWIGGS COUNTY SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	REDI 1400 MW - US 2: COOL SPRINGS	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
	REDI 1400 MW - US 2: HICKORY PARK	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	REDI 1400 MW - US 2: QUITMAN II	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	REDI CS2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUPERIOR - WASTE MANAGEMENT	6	6	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
	WALTON COUNTY	465	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 7	-	622	622	622	622	622	622	622	622	622	622	-	-	-	-	-	-	-	-	-	-	-
	WASHINGTON COUNTY	313	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dispatchable DSOs (MW)		**675**	**696**	**716**	**758**	**805**	**750**	**752**	**750**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**
	CVR Level 1	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310
	CVR Level 2	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155
	DER Customer Program	-	21	47	89	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148
	DPEC	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
	RTPeDA	46	46	44	44	39	18	18	17	16	16	16	16	16	16	16	16	16	16	16	16	16	16
	RTPeHA	69	69	66	66	58	25	26	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25

DG/LM-17:
GPC Response to STF-JKA-4-14

STF-JKA-4-14

Question:

Please refer to Bullet Point BESS on page 27 and the Commission's Approval of BESS resources in the 2022 IRP.

a. Please provide a list of battery storage projects currently installed or being installed on the Georgia Power system, provide important details about the BESS projects such as when they were installed or will be installed, how they are or will be operated, and what operational experience has been gained so far, or is expected to be gained.

b. Are the BESS resources the Company is requesting approval in this proceeding covered under the 500 MW of BESS approved in the 2022 IRP (See Paragraph 73 of the Order Adopting the Stipulation in the 2022 IRP, dated July 29, 2022)? Or is the Company's request in addition to the 500 MW that the Commission previously approved. If so, discuss whether the Company needs approval in this proceeding.

c. Referring to the statement that "Georgia Power proposes to develop, own, and operate up to 1,000 MW of BESS and or BESS plus Solar at various sites" referenced on page 27 - is this amount in excess of the BESS resources currently in operation or under construction or planned and approved? If so, please explain why the Company seeks such approval at this time.

d. Please provide a complete reconciliation of the Company's request in this proceeding with the BESS resources already previously approved by the Commission, such as in the 2019 and 2022 IRPs.

Response:

a. A table of battery storage projects being installed on the Georgia Power system is provided below. The projects being installed will serve a variety of use-cases such as operating reserves, regulation, energy arbitrage, and solar shifting. Further, as a result of Company ownership, the Company can incorporate operational changes with these Battery Energy Storage Systems ("BESS") as additional use cases are identified. The Company expects that all BESS will operate on Automatic Generation Control ("AGC") and be optimized for the overall system. After Mossy Branch achieves commercial operation, it will operate in a testing phase to refine the AGC algorithm, which will be applied to future BESS.

Project Name	COD
Mossy Branch	2024
Fort Stewart	2026
McGrau Ford	2026
Robins	2026
Moody	2026
200 MW BESS plus 200 MW Solar	2026

b. The 500 MW of energy storage system ("ESS") resources approved in the 2022 Integrated Resource Plan ("IRP") was for a request for proposals ("RFP") to the market and is not part of the 1,000 MW requested in the 2023 IRP Update.

c. Yes, the 1,000 MW of BESS are in excess of the BESS resources currently in operation, under construction, or planned and approved but the 1,000 MW includes Robins, Moody and 200 MW BESS plus 200 MW Solar listed in part a. The Company is seeking 1,000 MW in excess of what was previously approved because of the drastic changes in economic load growth from the conclusion of the 2022 IRP until now as detailed in the Company's 2023 IRP Update. The 1,000 MW will be used to meet capacity needs, while the previous approvals of BESS were demonstration projects or projects to serve as operating reserves to support the continued addition of intermittent resources on the system.

d. Please see the chart below for a complete reconciliation of the Company's request in this proceeding with the BESS resources already previously approved by the Commission, such as in the 2019 and 2022 IRPs.

IRP	Request
2019 IRP	80 MW Demonstration
2022 IRP	265 MW McGrau Ford 500 MW ESS RFP
2023 IRP Update	1,000 MW of BESS • Robins – 128 MW • Moody – 49.5 MW • BESS co-located with solar – 200 MW • Remaining MW to be determined – 622 MW Flex Capacity options beyond the 1,000 MW

DG/LM-18:
GPC Response to STF-JKA-2-11, Attachment F

Winter

Total	Avg Trended	Incremental	FINAL Incremental with 37.5GW of Solar
1,000	100%	1,000	100%
2,000	100%	1,000	100%
3,000	99%	1,000	98%
4,000	97%	1,000	92%
5,000	95%	1,000	84%
6,000	92%	1,000	75%
7,000	88%	1,000	65%
8,000	84%	1,000	55%
9,000	79%	1,000	45%
10,000	75%	1,000	37%
11,000	71%	1,000	30%
12,000	67%	1,000	27%
13,000	64%	1,000	26%
14,000	61%	1,000	25%
15,000	59%	1,000	24%

Summer

Total	Avg Trended	Incremental	FINAL Incremental with 37.5GW of Solar
1,000	92%	1,000	92%
2,000	97%	1,000	100%
3,000	100%	1,000	100%
4,000	100%	1,000	100%
5,000	99%	1,000	95%
6,000	97%	1,000	85%
7,000	93%	1,000	73%
8,000	89%	1,000	59%
9,000	84%	1,000	46%
10,000	79%	1,000	33%
11,000	74%	1,000	23%
12,000	69%	1,000	16%
13,000	65%	1,000	13%
14,000	61%	1,000	12%
15,000	58%	1,000	11%

FINAL Aurora Tranches
100%
85%
55%
30%

FINAL Aurora Tranches
100%
95%
60%
20%

DG/LM-19:
GPC Response to TS STF-PIA-10-1

Fully Redacted as it Contains
Trade Secret Information

DG/LM-20:
GPC Response to PD STF-JKA-1-4

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-1-4

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-1-4 ("Response"). In the Response, the Company has provided data supporting the economic analysis of projects proposed in the 2023 IRP Update including an acquisition with sensitive pricing and confidential details (the "Information"). All of such information constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives 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 its disclosure or use. Specifically, the Information includes competitively sensitive details specific to the resources under contract, proposed to be acquired or 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. In addition, the terms of the agreements themselves provides for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in current and future negotiations, as counterparties may use the Information as a bargaining tool in negotiations or fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-1-4

Question:

See the file – TS Economic Analysis of Capacity Resources.xlsx, and the tab – Term Equalization.

a. For each capacity value between cells G4 and BC16 that are pasted in, provide workpapers used to derive the pasted values.

b. Row 2 of the tab shows capacity need years and shows that a need exists in 2027. Does that represent 2 years advancement of the need year or 3? If it represents 2 years explain why that was used as opposed to 3 years given the Company latest position is that the need year has advanced by 3 years compared to the 2022 IRP.

c. Cell J20 contains a pasted value of **REDACTED**. Please provide all workpapers used to derive that value, electronically with all formulae intact. Also, explain why **REDACTED REDACTED** costs were used for the Marginal cost of capacity. Also, please confirm that value includes both capacity and energy value.

d. Explain why in the case of **REDACTED**, capacity value exists in **REDACTED**, not **REDACTED**, and then again beginning in **REDACTED** and after. Why doesn't it exist in **REDACTED**?

e. Explain why capacity value for Yates 8-10 **REDACTED REDACTED**?

f. Explain why capacity value for **REDACTED** BESS +Solar **REDACTED**.

g. Explain what the Cost of Equalization is assumed to represent.

Response:

a) Please see TS STF-JKA-1-4 Attachment. This attached is redacted in its entirety to preserve working formulae.

b) The Company has a need in the winter of 2025/2026 or a 3-year advancement from the 2022 IRP. The need in winter 2025/2026 is 175 MW which grows to 1,875 MW in the winter 2026/2027. Given the relatively small winter of 2025/2026 need, the Company's economic ranking analysis assumed the first year for term equalization costs would be winter 2026/2027 to establish a relative economic ranking of resource options.

c) Please see cell F2 in the "YatesCT" tab of the "TS SAM ('23) - 7.0.1 YatesCT Final.xlsm" workpaper provided to Commission Staff on October 27, 2023. A combustion turbine resource continues to represent the lowest repeatable fixed costs option or capacity resource to meet peak demands. Plant Yates Units 8-10 represent the most recent information on the costs of a new combustion turbine. Therefore, it was used to represent the marginal costs of capacity.

The value in cell J20 is only the fixed costs and does not include energy value. Energy value is reflected on row 21 and included in the net cost of capacity on row 22 of the same spreadsheet and tab.

d) The value in 2030 is not for capacity value of the resource. Rather, it represents term equalization capacity and is used to impute a capacity cost to the resource to reflect periods when **REDACTED** **REDACTED** cannot provide reliable capacity. This is considered for the summer of 2030 as the transmission system upgrades will not be in place by the summer of 2030 for this option. In calendar year 2030, the Company's capacity constraint switches from winter to summer due to the timing of PPA expirations. **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**. Please see TS STF-JKA-1-4 Attachment for more information.

e) The values in 2027 and 2028 are not for capacity value of the resource. Rather, they represent term equalization capacity and are used to impute a capacity cost to the resource to reflect periods when the proposed Plant Yates Units 8-10 cannot provide full output. Transmission system upgrades will not be completed until May of 2028. Until these upgrades are completed, Plant Yates Units 8-10 will be limited to 600 MW during peak conditions. An additional capacity cost is imputed to the resource to reflect the resource limitations. Please see TS STF-JKA-1-4 Attachment for more information.

f) The value in 2030 is not for capacity value of the resource. Rather, it represents term equalization capacity and is used to impute a capacity cost to the resource during the summer of 2030, which is the constraining season for that year. **REDACTED** BESS + Solar is assumed to provide 100% ELCC in the winter and 50% ELCC in the summer. Please see TS STF-JKA-1-4 Attachment for more information.

g) Please see section 3.5 of Technical Appendix Economic Analysis of Capacity Resources.

DG/LM-21:

GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B

Fully Redacted as it Contains Trade Secret Information

DG/LM-22:
GPC Response to STF-PIA-10-6

STF-PIA-10-6

Question:

Please refer to the proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 88 Fed. Reg. 18824 (Mar. 29, 2023) (the "Proposed 2023 ELG Rule").

a. Does the Company anticipate incurring costs for retrofits at the Bowen and Scherer coal units between now and 2029 to comply with the zero-discharge limitation for all pollutants in flue gas desulfurization (FGD) wastewater under the Proposed 2023 ELG Rule? If yes, please describe the capital projects that are required, and the estimated costs associated with them. If not, please explain why not.

b. Does the Company anticipate incurring costs for retrofits at the Bowen and Scherer coal units between now and 2029 to comply with the zero-discharge limitation for all pollutants in bottom ash transport water (BATW) under the Proposed 2023 ELG Rule? If yes, please describe the capital projects that are required, and the estimated costs associated with them. If not, please explain why not.

c. Will the Proposed 2023 ELG rule require any capital expenditures at the Bowen and Scherer coal units between now and 2029 to comply with the numeric discharge limitations for combustion residual leachate (CRL)? If yes, please describe the capital projects that are required, and the estimated costs associated with them. If no, please explain why not.

Response:

a. If the U.S. Environmental Protection Agency ("EPA") finalizes the Proposed 2023 ELG Rule, the Company anticipates incurring additional capital costs if Plant Bowen is required to install membrane-based wastewater treatment and meet a zero-liquid discharge ("ZLD") requirement for flue gas desulfurization ("FGD") wastewater. See STF-PIA-10-6 Attachment for Southern Company's comments on the Proposed 2023 ELG Rule submitted to EPA on May 30, 2023, which includes a screening level estimate of approximately $580M for membrane-based FGD wastewater treatment at Plant Bowen. This does not include costs for a ZLD system, which would likely include additional storage tanks, pumps, and piping to reuse the permeate/distillate as make-up water to the boiler or FGD.

   The Company does not anticipate incurring additional costs at Plant Scherer beyond the membrane-based FGD wastewater treatment project that is currently underway, because the proposed rule did not indicate changing the requirements for the Voluntary Incentives Program that is applicable to Plant Scherer.

b. The Company does not anticipate incurring additional capital costs for retrofits at Plants Bowen and Scherer for bottom ash transport water under the Proposed 2023 ELG Rule. Both facilities already meet the requirements of the proposed ELG requirements for bottom ash

transport water with systems that were installed by 2019 to facilitate ash pond closure and meet existing ELG requirements.

c. If EPA finalizes the Proposed 2023 ELG Rule, the Company anticipates incurring additional capital costs for retrofits if physical-chemical wastewater treatment systems are required for combustion residual leachate at coal combustion residual landfills. The Company does not yet have capital cost estimates for these treatment systems, and site-specific studies for the landfills at Plants Bowen and Scherer are currently underway to prepare for cost estimating activities once the final rule is released.

DG/LM-23:
GPC Response to STF-PIA-10-7

STF-PIA-10-7

Question:

Please refer to the proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33240 (May 23, 2023) (the "Proposed 2023 GHG Rule").

a. Has the Company evaluated the four different compliance options for compliance with the Proposed 2023 GHG Rule at the Bowen and Scherer coal units? If yes, please provide all documents supporting this evaluation. If not, please explain why not.

b. Does the Company anticipate retiring the Bowen and/or Scherer coal units prior to 2032 to avoid compliance with the Proposed 2023 GHG Rule?

c. Does the Company anticipate retiring the Bowen and/or Scherer coal units prior to 2035 and accepting an operational limit of 20% of full capacity starting in 2030 as one of the compliance options under the Proposed 2023 GHG Rule?

d. Has the Company analyzed the cost of installing carbon capture and storage with a 90% capture rate to comply with the Proposed 2023 GHG Rule? If yes, please provide all such analysis. If not, state whether the Company plans to issue any updates to the IRP that evaluate the impact that the Proposed 2023 GHG Rule on the cost to operate the system.

Response:

a. The Company has not evaluated the existing coal unit compliance options for the United States Environmental Protection Agency's ("EPA") Proposed 2023 GHG Rule for Plants Bowen and Scherer, such as the early retirement by 2032 or 2035 and carbon capture and sequestration options. Even if the rule is finalized as proposed, a compliance evaluation cannot be completed at this time, because uncertainty remains in the compliance options and requirements for existing facilities until the development of the Georgia state plan required by the rule. EPA has indicated that it plans to finalize the Proposed 2023 GHG Rule in 2024 and proposed that the state plan would be due two years later. The Company will work with the Georgia Environmental Protection Division to evaluate the final 2023 GHG Rule and compliance options for affected existing facilities in the development of the Georgia state plan, which then must also be reviewed and approved by EPA.

   As stated generally in comments submitted by Southern Company to EPA on August 8, 2023 (see STF-JKA-2-14 Attachment C), more time and compliance flexibility are required in the case of all four existing coal unit options presented in the proposal. The Company will update the Commission through a future Environmental Compliance

Strategy and IRP process when sufficient information becomes available to complete the compliance evaluation.

b. See response to subpart (a).

c. See response to subpart (a).

d. See response to subpart (a).

DG/LM-24:
GPC Response to STF-PIA-7-4

STF-PIA-7-4

Question:

Please identify all assumptions and constraints included in the Company's 2023 IRP Update and modelling associated with, or in consideration of, the U.S. Environmental Protection Agency's (US EPA) proposed New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule. [U.S. EPA Docket No. EPA–HQ–OAR–2023–0072]

a. Please describe each assumption or constraint.

b. Explain the rationale for including the assumption or constrain.

c. Please provide all documentation, memos, industry reports, and workpapers describing these limitations, modeled or operational, and modeling choices to support these assumptions and constraints.

d. If no assumptions or constraints were included in the Company's 2023 IRP Update, please explain why this is the case.

Response:

a. The Company did not include any assumptions or constraints as proposed in EPA 111 in the 2023 IRP Update.

b. The Company did not include any assumptions or constraints as proposed in EPA 111 in the 2023 IRP Update.

c. The Company did not include any assumptions or constraints as proposed in EPA 111 in the 2023 IRP Update.

d. Since the proposed EPA 111 rule has yet to be finalized, state plans have not yet been developed, and potential legal challenges have not yet taken place, the Company believes that detailed analysis of the implications of the proposed EPA 111 rule for the 2023 IRP Update would be premature and speculative. The Company believes that the implications of a final EPA 111 rule are captured within the range of carbon pressure scenarios included in the 2023 IRP Update.

Contact: Jeff Grubb

DG/LM-25:
GPC Response to STF-JKA-2-8

STF-JKA-2-8

Question:

Main document page 27 states: "In the 2022 IRP Final Order, the Commission approved the retirement and decertification of Plant Scherer Unit 3 and Plant Gaston Units 1-4 and Unit A by December 31, 2028. With continuing increases to the projected load forecast and capacity needs following 2028, the Company will likely evaluate extending the operation of certain units, particularly Plant Scherer Unit 3, beyond 2028."

a. Confirm that the Company has modeled Scherer 3 with retirement in 12/31/2028 in all of the Aurora runs modeled.

b. Does the Company believe the Aurora modeling reflects the Company's most up-to-date understanding of its capacity plan?

Response:

a. Yes, Plant Scherer Unit 3 was modeled with a resource end date of 12/31/2028 in all of the Aurora runs.
b. Yes, the Company believes that its system modeling using Aurora for this 2023 IRP Update provides the most up-to-date understanding of its capacity plan at this time. As stated in the 2023 IRP Update Main Document, with the increase in capacity needs in 2028 and beyond, the Company is assuming Bowen Units 1-2 will retire at the end of 2035 for planning purposes. Also, while the current assumed retirement date for Scherer Unit 3 and Plant Gaston Units 1-4 and Unit A are at the end of 2028, the Company will likely evaluate extending operation of certain units beyond 2028 in the 2025 IRP.

Contact: Mike Bush