

**BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

In Re:

**GEORGIA POWER COMPANY'S 2025) DOCKET NO. 56002
INTEGRATED RESOURCE PLAN)**

**GEORGIA POWER COMPANY'S 2025) DOCKET NO. 56003
APPLICATION FOR THE CERTIFICATION,)
DECERTIFICATION, AND AMENDED)
DEMAND SIDE MANAGEMENT PLAN)**

**DIRECT TESTIMONY

AND EXHIBITS

OF

RALPH C. SMITH

AND

JASON R. FORSYTHE**

**On Behalf of the
Georgia Public Service Commission
Public Interest Advocacy Staff**

Public Disclosure Version

May 5, 2025

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<u>Exhibit</u>	<u>Description</u>
RCS-1	Ralph C. Smith Background and Qualifications
JRF-1	Jason R. Forsythe Background and Qualifications
RS/JF-2	Georgia Power's response to STF-LA-1-7 in the current docket and Georgia Power's response to Trade Secret STF DEA-3-6 Supplemental from the GPC 2023 IRP Update, Docket No. 55378, related to the "downward pressure" on customer rates from the 2023 IRP Update proceeding and the Company's 2025 IRP financial review.
RS/JF-3	Georgia Power's GPC 2022 IRP, Docket Nos. 44160 and 44161 responses to STF-LA-2-20, STF-LA-3-4, and STF-LA-3-5 from the 2022 IRP, Docket Nos. 44160 and 44161, regarding the Additional Sum amounts.
RS/JF-4	Georgia Power's response to Trade Secret STF-LA-1-8, regarding Production Tax Credits and Investment Tax Credits.
RS/JF-5	Georgia Power's responses to Trade Secret STF-LA-1-9 (without voluminous attachment), Trade Secret STF-LA-1-12, Trade Secret STF-LA-1-14, Trade Secret STF-LA-1-15, and Trade Secret STF-LA-1-16, STF-LA-1-18, STF-LA-1-19, and STF-LA-1-20 relating to the Environmental Compliance Cost Recovery (ECCR) costs including Capital Expenditures, Plant Closures, O&M Expenses, and amount of contingency included.
RS/JF-6	Georgia Power's responses to Trade Secret STF-LA-1-26 (without voluminous attachments), STF-LA-1-27, Trade Secret STF-LA-1-28 (without voluminous attachments), Trade Secret STF-LA-1-29, and STF-LA-30 regarding CCR costs and accounting entries.
RS/JF-7	Georgia Power's response to Trade Secret STF-LA-1-25 (without voluminous attachments) concerning costs incurred to implement beneficial uses of harvested CCR and related revenue.

RS/JF-8 Georgia Power's response to STF-LA-1-38 regarding the extension of Plant Scherer Unit 3 and Plant Gaston Units 1-4 and a Beyond December 31, 2028.

1 **I. INTRODUCTION**

2
3 **Q. MR. SMITH, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

4 A. Ralph C. Smith, 15728 Farmington Road, Livonia, Michigan 48154.

5
6 **Q. WHAT IS YOUR OCCUPATION?**

7 A. I am a certified public accountant and a senior regulatory utility consultant with the firm
8 Larkin & Associates, PLLC, certified public accountants and regulatory consultants.

9
10 **Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL**
11 **BACKGROUND AND PROFESSIONAL EXPERIENCE?**

12 A. Yes. It is presented in Exhibit RCS-1. This exhibit summarizes my regulatory experience
13 and qualifications.

14
15 **Q. MR. FORSYTHE, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

16 A. Jason R. Forsythe, 244 Washington St. SW, Atlanta, Georgia 30334.

17
18 **Q. WHAT IS YOUR OCCUPATION?**

19 A. I am a Utilities Analyst in the Electric Section at the Georgia Public Service Commission
20 ("Commission").

21
22 **Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL**
23 **BACKGROUND AND PROFESSIONAL EXPERIENCE?**

24 A. Yes. It is presented in Exhibit JRF-1. This exhibit summarizes my regulatory experience
25 and qualifications.

26

1
2 **Q. ON WHOSE BEHALF ARE YOU APPEARING?**

3 A. We are testifying on behalf of the Georgia Public Service Commission Public Interest
4 Advocacy Staff (“Staff”).

5
6 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

7 A. The purpose of our testimony is to address certain accounting and ratemaking issues
8 proposed by Georgia Power Company (“Georgia Power” or “Company”) in the Company’s
9 2025 Integrated Resource Plan (“2025 IRP”) proceeding.

10
11 We address generally the requests of Georgia Power for approval of specific costs. The
12 Company is requesting approval for several categories of costs, but not yet for the recovery
13 of such costs. An Integrated Resource Plan (“IRP”) proceeding is not the appropriate
14 forum for addressing ratemaking issues that should be addressed in a forum such as a rate
15 case that also considers the Company’s earnings and risk.

16
17 In Section II, we discuss the statements made by the Company in Docket No. 55378, the
18 2023 IRP Update proceeding concerning expectations for “downward pressure on rates”
19 and the “2025 IRP Financial Review” section of the Company’s IRP . We discuss the
20 Company’s presentation of estimated revenue requirements and real levelized cents-per-
21 kWh increases in the “2025 IRP Financial Review” section of Technical Appendix Volume
22 2 of Georgia Power’s 2025 IRP.

23
24 In Section III, we address regulatory accounting deferrals.

25

1 In Section IV, we discuss the accounting and historical ratemaking treatment of Additional
2 Sum for capacity Purchased Power Agreements (“PPAs”). Other Staff panels are
3 presenting recommendations concerning the Company’s requested Additional Sums for
4 capacity PPAs at a rate of \$4.00 /kW-year and the Company’s requests for increased
5 Additional Sum amounts related to Demand Side Management (“DSM”) programs.
6

7 In Section V, we address income tax incentives related to the development of renewable
8 energy, such as solar generation, and battery energy storage.
9

10 In Section VI, we discuss the Company’s request for approval of its Environmental
11 Compliance Strategy (“ECS”) and associated costs for Environmental Compliance Cost
12 Recovery (“ECCR”). The Company’s ECS includes cost recovery for Coal Combustion
13 Residual (“CCR”) Asset Retirement Obligations (“AROs”).
14

15 In Section VII, we discuss the approximate costs the Company has estimated for Asset
16 Retirement Obligations (“ARO”) for Coal Combustion Residual (“CCR”) rule compliance.
17 The Company has established a semi-annual reporting protocol to keep Staff updated with
18 its CCR spending and changes in its ash pond closures and ash pond and landfill
19 remediation activities. Overall, the Company projects spending approximately \$7.964
20 billion on CCR compliance, with spending projected to occur beyond 2035.¹ The
21 Company’s projected CCR spending includes significant amounts for contingencies.
22 Recovery of costs related to CCR will be an issue in the Company’s rate case.
23

¹ See, Technical Appendix, Volume 2, tab CCR ARO, page 1 of 16.

1 In Section VIII, we discuss the costs incurred and revenue received and expected related
2 to the Company's programs for the Beneficial Use of coal ash and gypsum. Staff is
3 concerned that the Company's beneficial use activities involve up-front investments and
4 costs, and projects future revenues and cost savings that might or might not materialize,
5 and thus could result in net overall cost increases to ratepayers. Staff recommends that the
6 Commission direct the Company to present additional information prior to or in
7 conjunction with its upcoming rate case so there can be confidence that the Beneficial Use
8 will more assuredly provide net cost savings, and not become an additional cost burden on
9 ratepayers, prior to approving the program. The Company is using Requests for Proposals
10 ("RFPs") for certain aspects of the beneficial use programs. Once the Company evaluates
11 responses to the Beneficial Use RFP process, Staff recommends that the Commission direct
12 the Company to use that information to update its net present value cost benefit analysis,
13 and to present the updated NPV analysis for consideration in the Company's upcoming
14 rate case.

15
16 In Section IX, we address how the Company's proposal for extending the retirement dates
17 at certain generating facilities could impact depreciation expense.

18
19 **Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?**

20 A. Yes. In addition to our qualifications, which are in Exhibit RCS-1 and JRF-1, respectively,
21 Staff has attached Exhibits RS/JF-2 through RS/JF-8 which contain Company responses to
22 discovery and other materials referenced in our testimony.

23
24 **Q. WHAT IS SHOWN IN EXHIBIT RS/JF-2?**

25 A. Exhibit RS/JF-2 contains the Company's response to STF-LA-1-7 in the current docket
26 and Georgia Power's response to Trade Secret STF DEA-3-6 Supplemental from the GPC

1 2023 IRP Update, Docket No. 55378. This material is related to the “downward pressure”
2 on customer rates from the 2023 IRP Update proceeding and the Company’s 2025 IRP
3 financial review.
4

5 **Q. WHAT IS SHOWN IN EXHIBIT RS/JF-3?**

6 A. Exhibit RS/JF-3 contains Georgia Power’s responses to STF-LA-2-20, STF-LA-3-4, and
7 STF-LA-3-5 from the 2022 IRP, Docket Nos. 44160 and 44161, regarding the Additional
8 Sum amounts.
9

10 **Q. WHAT IS SHOWN IN EXHIBIT RS/JF-4?**

11 A. Exhibit RS/JF-4 contains Georgia Power’s response to Trade Secret STF-LA-1-8,
12 regarding Production Tax Credits and Investment Tax Credits.
13

14 **Q. WHAT IS SHOWN IN EXHIBIT RS/JF-5?**

15 A. Exhibit RS/JF-5 contains Georgia Power’s responses to Trade Secret STF-LA-1-9 (without
16 voluminous attachment), Trade Secret STF-LA-1-12, Trade Secret STF-LA-1-14, Trade
17 Secret STF-LA-1-15, and Trade Secret STF-LA-1-16, STF-LA-1-18, STF-LA-1-19, and
18 STF-LA-1-20 relating to the Environmental Compliance Cost Recovery (ECCR) costs
19 including Capital Expenditures, Plant Closures, O&M Expenses, and amount of
20 contingency included.
21

22 **Q. WHAT IS SHOWN IN EXHIBIT RS/JF-6?**

23 A. Exhibit RS/JF-6 contains the Company’s responses to Trade Secret STF-LA-1-26 (without
24 voluminous attachments), STF-LA-1-27, Trade Secret STF-LA-1-28 (without voluminous
25 attachments), Trade Secret STF-LA-1-29, and STF-LA-30 regarding CCR costs and
26 accounting entries.

1

2 **Q. WHAT IS SHOWN IN EXHIBIT RS/JF-7?**

3 A. Exhibit RS/JF-7 contains the Company’s response to Trade Secret STF-LA-1-25 (without
4 voluminous attachments) concerning costs incurred to implement beneficial uses of
5 harvested CCR and related revenue.

6

7 **Q. WHAT IS SHOWN IN EXHIBIT RS/JF-8?**

8 A. Exhibit RS/JF-8 contains the Company’s response to STF-LA-1-38 regarding the extension
9 of Plant Scherer Unit 3 and Plant Gaston Units 1-4 and a Beyond December 31, 2028.

10

11 **Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS ON THESE**
12 **ISSUES?**

13 A. Staff’s conclusions and recommendations are as follows:

14

15 **1. Downward Pressure on Rates**

16 In the 2023 IRP Update proceeding, the Company stated that it was their expectation that
17 the addition of several new large load customers would put “downward pressure on rates.”

18 As noted in Staff’s testimony in that proceeding, for various reasons, the Company’s
19 statements that it expected that there would be “downward pressure on rates” does not
20 provide assurance that rates for all customer classes, such as for residential and small
21 business customers, would not be subject to increased rates. In the 2023 IRP Update
22 proceeding, Staff noted that several of the Company’s requests, such as but not limited to,
23 the Company’s requests for new regulatory accounting deferrals and for new Additional
24 Sums would put upward pressure, not downward pressure, on rates in the Company’s next
25 rate case. Staff has continuing concerns with the Company’s 2025 IRP that additional costs
26 being incurred by the Company to serve growth from adding new large load customers to

1 its system will put upward pressure on residential and small business customers rates. As
2 described by other Staff panels, there is uncertainty in the economic outlook and whether
3 the addition of the new large load customer revenues in the amounts projected by the
4 Company will materialize in a timely manner and be sufficient to cover the additional costs
5 being incurred to serve those new large load customers. The Newsome-Hayet-Sandonato-
6 Wellborn testimony is discussing the impact on the revenue requirement for ratepayers
7 from the requests being made by the Company in this 2025 IRP proceeding which are
8 mostly being driven by the addition of several new large load customers. Consequently,
9 one possible alternative protecting residential and small commercial rate classes from
10 having to pay for increased costs being incurred to serve new large load customers would
11 be to require that the impact of the incremental costs to serve such customers must be
12 absorbed by the rate classes into which such large load customers are being added. That
13 could potentially be one way of avoiding upward pressure on the rates of existing smaller
14 customers from the incremental costs to serve the new large load customers that the
15 Company has requested.

16 17 **2. Additional Sums for New Purchased Power Agreements**

18 The Company has requested Commission approval for Additional Sum amounts at \$4.00
19 per kW-year for new Capacity and Energy Purchased Power Agreements (“PPAs”).
20 Additional Sum amounts may be granted by the Commission pursuant to the guidance
21 provided in O.C.G.A. § 46-3A-8. The Additional Sum amounts, once approved by the
22 Commission, have effectively functioned as additional revenue to the Company which
23 produces pre-tax profits to shareholders that has not been subjected to earnings sharing.
24 Additional Sum amounts for PPAs approved in the Company’s 2022 IRP were set at
25 \$3.00/kW-year for new PPAs that were not put to an RFP and competitive bidding process.
26 In the 2023 IRP Update proceeding, Additional Sum amounts were authorized at

1 \$4.00/Kw-year for new capacity PPAs addressed in that proceeding. Historically, for
2 earnings sharing purposes, the revenues related to Additional Sums have been excluded
3 from consideration in the reviews of the Company’s earnings and earnings sharing that
4 occur in conjunction with the reviews by Staff of the Company’s Annual Surveillance
5 Reports. Staff Pane of Barber, Kaduk, and Bower is addressing the Company’s request for
6 Additional Sum amounts on new capacity and renewable energy PPAs. The issue of
7 including Additional Sums in the reviews of the Company’s earnings and earnings sharing
8 may be a subject to be addressed in the Company’s upcoming rate case. Staff reserves the
9 right to challenge regulatory accounting treatment of Additional Sums in subsequent rate
10 cases.

11 12 **3. Federal Income Tax Incentives for Renewable Energy and Energy Storage**

13 Our testimony briefly discusses some of the federal income tax incentives provided by the
14 Inflation Reduction Act (“IRA”) and how those incentives could affect resource selection.
15 The Company was aware of and considered many of the tax incentives that have been made
16 available by the IRA, including production tax credits and investment tax credits. While
17 there is some uncertainty concerning whether tax incentives provided in the IRA could be
18 curtailed or withheld, there may be further opportunities for additional behind-the-meter
19 resources and energy efficiency that could provide resources beyond what the Company
20 has presented in its 2025 IRP to help address growth in load and peak demand that the
21 Company is projecting related to adding several new large customers within and outside of
22 its service territory.

23 24 **Approval of the Company’s Environmental Compliance Plan and Cost**

25 An IRP proceeding is the appropriate forum for the Commission to consider approval of
26 the Company’s ECS. However, an IRP proceeding is not the appropriate forum to approve

1 costs associated with the ECS. The reasonableness of the cost is dependent on many
2 factors, including the Commission’s resource decisions in this docket and, ultimately, the
3 Company’s execution of its ECS. An assessment of the Company’s execution is properly
4 made after the ECS has been implemented and the costs have been incurred. Staff
5 recommends that the Commission decline to approve specific costs listed in the
6 Environmental Compliance Cost Recovery (“ECCR”) tables in the Selected Supporting
7 Information Section of Technical Appendix Volume 2. Staff recommends that such costs
8 should be reviewed and subject to Commission approval in the Company’s rate case.
9

10 **Coal Combustion Residuals**

11 CCR Asset Retirement Costs (“ARO”) are a component of the Company’s ECS. Similar
12 to the Company’s request for approval of costs listed by the Company ECCR, Staff’s view
13 is that an IRP proceeding is not the appropriate forum to approve projected CCR ARO
14 costs. The reasonableness of the cost is dependent on many factors, including the
15 Company’s timing of its incurrence of CCR ARO costs. Staff recommends that the
16 Commission decline to approve specific CCR ARO costs listed by the Company in the
17 tables in the Selected Supporting Information Section of Technical Appendix Volume 2.
18 Staff recommends that such costs should be reviewed and subject to Commission approval
19 in the Company’s rate case.
20

21 **Beneficial Use of CCR**

22 The Company has been incurring up-front costs to enable the beneficial use of CCR. Staff
23 discusses information obtained from the Company in discovery concerning the cost of
24 enabling beneficial use, and related amounts of revenue. While Staff believes that
25 beneficial uses of CCR could help reduce the Company’s CCR compliance costs, there are
26 some concerns about whether the resultant revenues and cost savings will be sufficient to

1 offset the up-front costs and result in net benefits to customers. The costs and revenues
2 related to the Company’s beneficial uses of CCR can appropriately be reviewed in the
3 Company’s rate case.
4

5 **II. COMPANY STATEMENTS FROM THE 2023 IRP UPDATE PROCEEDING**
6 **CONCERNING “DOWNWARD PRESSURE ON CUSTOMER RATES” AND THE**
7 **“2025 IRP FINANCIAL REVIEW” PRESENTED IN THE CURRENT CASE**
8

9 **Q. IN THE 2023 IRP UPDATE PROCEEDING, DID THE COMPANY MAKE**
10 **STATEMENTS ABOUT EXPECTING TO HAVE “DOWNWARD PRESSURE ON**
11 **CUSTOMER RATES” IN ITS DIRECT TESTIMONY, APPLICATION AND**
12 **DURING THE HEARINGS?**

13 A. Yes. For example, the Company’s Direct Testimony on page 10 in the 2023 IRP Update
14 Proceeding stated the following:

15 *All else being equal, we expect* that the projected revenues associated with incremental
16 load from these new customer projects will offset the costs of the resources requested
17 in this filing, and put downward pressure on our *overall* retail rates as we continue to
18 provide clean, safe, reliable, and affordable power for *all* of Georgia Power’s
19 customers in the coming years.

20 A similar statement is made on page 56 of the Company’s Direct Testimony in the 2023
21 IRP Update proceeding.
22

23 **Q. WERE ADDITIONAL STATEMENTS ABOUT “DOWNWARD PRESSURE ON**
24 **RATES” MADE DURING THE HEARING IN THE 2023 IRP UPDATE**
25 **PROCEEDING?**

26 A. Yes. During the hearing on Georgia Power Company’s direct testimony in the 2023 IRP
27 Update Proceeding, a number of statements were made by the Company regarding
28 “downward pressure on rates” including the following:

29 “...the IRP update identifies the effect of recent economic growth on the company's

1 load forecast and capacity needs and proposes a well-balanced portfolio and resource
2 plan that is expected to put downward pressure on rates for all customers and enable
3 Georgia Power to continue to provide clean, safe, reliable and affordable energy for
4 Georgia as it continues to grow and thrive.” (Tr. 0116.)

5 “To be clear, the economic growth we are seeing benefits our state. As I'll discuss, it
6 also benefits all Georgia Power customers by putting downward pressure on rates.”
7 (Tr. 0118.)

8 “Although there are costs associated with implementing the proposed resource plan,
9 Georgia Power is not requesting a rate adjustment in this IRP update. In fact, all else
10 being equal, the company does not expect customer rates to increase as a result of the
11 company's requests in this case. In addition to proposing a cost-effective means of
12 addressing the energy needs of our customers in this period of extraordinary economic
13 growth, the company's plan in this IRP update is expected to provide economic
14 benefits for all customers by placing downward pressure on rates.” (Tr. 0122.)

15
16 **Q. IN THE 2023 IRP UPDATE PROCEEDING, DID THE COMPANY MAKE ANY**
17 **FIRM COMMITMENT THAT ITS RATES WOULD NOT BE INCREASING IN**
18 **ITS NEXT RATE CASE, AS A RESULT OF THE REQUESTS BEING MADE IN**
19 **ITS 2023 IRP UPDATE?**

20 **A.** No. The Company has avoided making a firm commitment that rates for electric service
21 would not be increasing as a result of its 2023 IRP Update requests. The Company stated
22 in the 2023 IRP Update proceeding that, as noted above, with “all else being equal” it does
23 not expect that rates would increase. The Company also stated it expected “downward
24 pressure on rates.” When these Company statements from the 2023 IRP Update proceeding
25 are examined, there was no firm commitment from the Company that its rates, such as for
26 residential and small business customers, would not be increasing as a result of the
27 Company’s requests that are being made in the 2023 IRP Update, including Company
28 requests relating to incurring substantial costs to serve additional new large load customers.
29 As an illustrative example, the Company’s Direct Testimony panel in the 2023 IRP Update
30 proceeding was asked about this and responded as follows:

1 “CHAIRMAN SHAW: So I heard you say that the IRP update won't change rates, but
2 could it cause revenue requirements to go up and higher rates being necessary in the -
3 - in the 2025 rate case?

4 “MR. GRUBB: So from the -- the request in this filing, we do not expect upward
5 pressure on rates. We expect downward pressure on rates. And we say that based on
6 the analysis that we did and then provided in the data request where we looked at
7 exactly what you're asking. So we looked at the revenue requirements for all the
8 resources that we've requested in this IRP update compared to the revenues from the
9 incremental load that's driving the need for those resources. And that shows a -- a
10 higher level of revenues than it does revenue requirements for these resources;
11 thereby, putting downward pressure on all rates.” (Tr. 0135-0136.)

12
13 Commissioner Pridemore also expressed concern that the Company’s 2023 IRP Update
14 requests could in fact cause upward pressure on rates:

15 “COMMISSIONER PRIDEMORE: ... I'm very concerned about customer rates
16 related to this docket especially because what's being requested is a -- is a lot of
17 increased infrastructure.

18 “Mr. Grubb, you said that -- that rates are not likely to increase because of the result
19 of this docket. Determine to me what "likely" means and how can we move your
20 "likely" to a "will not increase"?

21 “MR. GRUBB: So I would say based on this filing, they will not put upward pressure
22 on rates. Mr. Evans can speak to the costing side on how we're doing. We mentioned
23 the rate impact measure test, but what we've done is what we've looked at and provided
24 in the DR was the revenue requirements for '26, '27, and '28 for these resources that
25 are coming online to serve customers and the revenues. And we actually did the
26 revenues at a lower load level than the resource plan. So we -- we have some -- a
27 little bit of headroom in there.

28 “So it's a -- a few hundred million dollars of downward pressure on rates from that
29 analysis. And that's why we say we're -- from this filing, we -- we expect downward
30 pressure for rates.”

31 “MR. EVANS: Yes. And I agree with everything Mr. Grubb said. I would also add
32 that the declining revenue requirement nature of the infrastructure invested, those
33 revenue requirements will go down over time. But that revenue will at least stay there
34 or increase over time. So all things being equal, the downward pressure on rates will
35 increase from what we filed.” (Tr. 0159-0160.)

1 Notably, the Company’s responses to questioning in the 2023 IRP Update proceeding
2 explained to some extent what “likely” meant but fell short of saying that rates “will
3 not increase” or to committing that rates would not increase due to the additional costs
4 of serving the unprecedented levels of new load being added to the system from the
5 new large load customers, or from other aspects of the Company’s requests, such as
6 for new cost deferrals and for new Additional Sums. In the 2023 IRP Update
7 proceeding, it appeared that the Company was also expecting that there would be a
8 declining revenue requirement for serving the new large load customers, i.e., that the
9 Company’s cost to serve them would go down over time. If that does not occur, i.e.,
10 if the revenue requirement for the added new large load customers remains stable or
11 increases, the “downward pressure on rates” that the Company expected might not pan
12 out as expected.

13
14 **Q. IN THE 2023 IRP UPDATE PROCEEDING, DID THE COMPANY PROVIDE**
15 **INFORMATION CONCERNING ESTIMATED IMPACTS IN 2026, 2027 AND**
16 **2028 ON OVERALL CUSTOMER REVENUE REQUIREMENTS?**

17 A. Yes. As one example, in the 2023 IRP Update proceeding, the Company’s supplemental
18 response to STF-DEA-3-6² stated in part that:

19 All else being equal, the Company expects that the projected revenues associated with
20 incremental load from known new customer projects, which necessitate the additional
21 capacity requested in the 2023 IRP Update, will fully offset the costs of those
22 resources requested in the 2023 IRP Update and put downward pressure on overall
23 retail rates. Please note, the projected revenues provided are preliminary estimates at
24 this point in time and may differ from future revenues. See TS STF-DEA-3-6
25 Attachments A-I for additional information.

26 One of the attachments to the Company’s supplemental response to STF-DEA-3-6,
27 Attachment A, in the 2023 IRP Update proceeding, is reproduced in the following Table

² A copy of that response is included in Exhibit RS/JF-2.

1 1, and shows information concerning the Company's estimates made at that time on
2 projected revenue requirement impacts for each year, 2026, 2027 and 2028:³

3
4 **Table 1 – Estimated Net Impacts to Customers**

Cumulative View			
	2026	2027	2028
Estimated Incremental Revenue Requirement due to Load Growth*	\$190	\$580	\$620
Estimated Incremental Revenue due to Load Growth**	\$340	\$680	\$860
Net Estimated Cumulative Impact to Customers	-\$150	-\$100	-\$240
Incremental View			
	2026	2027	2028
Total Revenues	\$10,970	\$10,660	\$10,760
Estimated Incremental Revenue Requirement due to Load Growth*	\$190	\$390	\$40
Estimated Incremental Revenue due to Load Growth**	\$340	\$340	\$190
Net Estimated Incremental Impact to Customers	-\$150	\$50	-\$150
Estimated Rate Impact (%)	-1.4%	0.5%	-1.4%
Cumulative (compounded) %	-1.4%	-0.9%	-2.3%
Estimated Typical Residential \$/month Impact	-\$2.58	\$0.86	-\$2.58
Cumulative Typical Residential \$/month Impact	-\$2.58	-\$1.72	-\$4.30

5
6 **Reflects projected transmission capital associated with Plant Yates 8-10. Does not*
7 *include revenue requirements for transmission projects that may be identified and placed*
8 *in service in 2026-2028 due to load growth.*

9
10 **Q. WHAT COSTS WERE INCLUDED IN THE COMPANY'S ESTIMATE OF THE**
11 **INCREMENTAL REVENUE REQUIREMENT DUE TO LOAD GROWTH?**

³ The supplemental response to STF-DEA-3-6, Attachment A shows the Company's preliminary estimates on projected revenue requirement impacts as public information. The Company had originally designated such information as Trade Secret, but in a supplemental response received on February 9, 2024, the Company removed the Trade Secret designation from some of that information.

1 A. The Company’s supplemental Trade Secret response to STF-DEA-3-6, Attachment A,
 2 from the 2023 IRP Update proceeding provided the following information concerning the
 3 Company’s estimates of costs that would be included in an incremental revenue
 4 requirement related to load growth preliminary estimates on projected revenue requirement
 5 impacts for each year, 2026, 2027 and 2028:

7 **Table 2 – Estimated Incremental Revenue Requirements**

8 **[BEGIN CONFIDENTIAL]**

Proposed Resource	2026	2027	2028
Mississippi Power PPA			
Santa Rosa PPA			
Moody BESS			
Robins BESS			
Co-located BESS			
Co-located Solar			
Other BESS			
Plant Yates Units 8-10			
Transmission Capex*			
Amortization of Reg Asset			
Total Estimated Incremental Revenue Requirement	\$190	\$581	\$618

9
 10 **Reflects projected transmission capital associated with Plant Yates 8-10. Does not*
 11 *include revenue requirements for transmission projects that may be identified and placed*
 12 *in service in 2026-2028 due to load growth.*

13 **[END CONFIDENTIAL]**

14
 15 **Q. DOES THE COMPANY’S “2025 IRP FINANCIAL REVIEW” PRESENTED IN**
 16 **THE CURRENT CASE SUGGEST THAT CUSTOMER RATES FOR 2026, 2027**
 17 **AND 2028 COULD BE INCREASING INSTEAD OF DECREASING?**

18 A. Yes. The Company’s presentation in the “2025 IRP Financial Review” section of

1 Technical Appendix Volume 2 in the 2025 IRP presents information for the various
2 scenarios evaluated by the Company on both a “Total Annual Revenue Requirement” basis,
3 on a “Nominal Average cents-per-kWh” basis, on a “Real Levelized Average cents-per-
4 kWh” basis and on a “Levelized Average cents per kWh” basis.⁴ Moreover, the
5 presentation in the “2025 IRP Financial Review” does not present base rate case revenue
6 requirements, as explained in the Company’s response to STF-LA-1-7(j).⁵ As explained
7 in the Company’s response to STF-LA-1-7(a): “... no scenarios represent the Company’s
8 full rate base and thus do not represent a total revenue requirement. The costs included for
9 the current generation are the variable costs only, which are then added to the full cost of
10 any additional generation needed as the system grows.”
11

12 **Q. ARE OTHER STAFF PANELS ADDRESSING THE COMPANY’S LOAD**
13 **FORECAST AND THE COSTS OF SOME OF THE ADDITIONAL RESOURCES**
14 **THAT THE COMPANY PROJECTS WILL BE NEEDED?**

15 A. Yes. The Trokey-Pol-Drugan panel is addressing the Company’s load forecast. That panel
16 and the Newsome-Hayet-Sandonato-Wellborn and Barber-Kaduk-Bower panels are
17 addressing the costs of some of the projected additional resources.
18

19 **Q. REFERRING BACK TO THE “2025 IRP FINANCIAL SUMMARY” IS ANOTHER**
20 **STAFF PANEL ADDRESSING THE ECONOMIC ANALYSIS UNDERLYING**
21 **THE GEORGIA POWER BASE CASE AND THE SENSITIVITY SCENARIOS?**

22 A. Yes. The Kennedy Associates panel is evaluating the Georgia Power base case and some
23 or all of the projected sensitivity scenarios.

⁴ Virtually all of the estimated revenue requirement and cents per kWh figures in the “2025 IRP Financial Review” section have been designated as TRADE SECRET information by the Company.

⁵ A copy of that response is included in Exhibit RS/JF-2.

1
2 **Q. HAVE YOU REVIEWED THE INFORMATION PROVIDED BY THE COMPANY**
3 **IN THE “2025 IRP FINANCIAL SUMMARY” AND SUPPORTING DETAILS**
4 **PROVIDED IN RESPONSES TO DISCOVERY?**

5 A. Yes.

6
7 **Q. WHAT DO THE REAL LEVELIZED REVENUE REQUIREMENT AND THE**
8 **LEVELIZED AVERAGE RATES PER KWH IN THE “2025 IRP FINANCIAL**
9 **SUMMARY” REPRESENT?**

10 A. As explained in the Company’s response to STF-LA-1-7(d): “The Levelized Revenue
11 Requirements represent the average cents per kWh if the load were to grow at the kWh
12 growth projected for each scenario.” As explained in the Company’s response to STF-
13 LA-1-7(b): “The Real Levelized Averages represent the average cents per kWh if the load
14 were to grow at the rate of inflation.”

15
16 **Q. WHAT GENERAL RATE OF INFLATION DID THE COMPANY ASSUME IN**
17 **THE “2025 IRP FINANCIAL SUMMARY”?**

18 A. For the general rate of inflation, the Company assumed [BEGIN CONFIDENTIAL] [REDACTED]
19 [REDACTED] [END CONFIDENTIAL].

20
21 **Q. WHY DO THE “LEVELIZED ANNUAL REVENUE REQUIREMENT”**
22 **AMOUNTS VARY FROM YEAR-TO-YEAR?**

23 A. As explained in the Company’s response to STF-LA-1-7(e):
24 The Levelized Revenue Requirements vary from year to year because they only
25 measure the current year and remaining years (e.g., 2026 calculates levelized 2026
26 through 2044, 2027 calculates 2027 through 2044).

27

1 **Q. DID THE COMPANY PROVIDE INFORMATION ON THE REVENUE**
2 **REQUIREMENT AMOUNTS WITHOUT LEVELIZATION?**

3 A. Yes. In response to STF-LA-1-7(f), the Company provided as TRADE SECRET
4 information, revenue requirements without levelization for each scenario.
5

6 **Q. DO ANY OF THE AMOUNTS IN THE “TOTAL ANNUAL REVENUE**
7 **REQUIREMENT” COLUMNS FOR YEARS 2026, 2027 OR 2028 REPRESENT**
8 **THE COMPANY’S ESTIMATES OF THE RATE CASE REVENUE**
9 **REQUIREMENT INCREASES FOR ANY OF THE SCENARIOS?**

10 A. No. As noted above and in the Company’s response to STF-LA-1-7(j), none of the
11 scenarios represent the Company’s base rate revenue requirements, and the generation
12 amounts are for variable costs only:

13 ... none of the scenarios represent the Company’s base rate case revenue requirements.
14 The Company has not yet prepared its 2025 base rate case budget, which is required
15 to be filed by July 1, 2025. Information about the future base rate case will be available
16 once the rate case has been prepared and filed. Please note, no scenarios represent the
17 Company’s full rate base and thus do not represent a total revenue requirement. The
18 costs included for the current generation are the variable costs only which are then
19 added to the full cost of any additional generation needed as the system grows.

20 Consequently, that information is not readily convertible into estimated 2025 base rate
21 case impacts.
22

23 **Q. FOR THE 2025 RATE CASE , WAS THE COMPANY ASKED WHETHER IT**
24 **WOULD BE REQUESTING LEVELIZED REVENUE REQUIREMENTS FOR**
25 **ANY YEARS BEYOND 2026-2028?**

26 A. Yes. That was asked in STF-LA-1-7(k).
27

28 **Q. WHAT WAS THE COMPANY’S RESPONSE?**

29 A. The Company’s response to STF-LA-1-7(k) states as follows:

1 The Company has not yet prepared its 2025 base rate case budget. Information about
2 the future base rate case will be available once the rate case has been prepared and
3 filed.

4

5 **Q. BASED ON THE INFORMATION PRESENTED IN THE 2023 IRP UPDATE**
6 **PROCEEDING AND IN THE “2025 IRP FINANCIAL SUMMARY” AND IN**
7 **RESPONSE TO DISCOVERY IN THE CURRENT PROCEEDING, IS STAFF**
8 **CURRENTLY EXPECTING GEORGIA POWER TO FILE FOR BASE RATE**
9 **DECREASES IN THE COMPANY’S 2025 RATE CASE?**

10 A. No. Based on the information presented in the 2023 IRP Update proceeding and in the
11 “2025 IRP Financial Summary” and in response to discovery in the current proceeding,
12 Staff’s current expectation is that Georgia Power’s upcoming rate case will not be
13 proposing a base rate decrease to become effective on January 1, 2026. While not a
14 complete revenue requirement, the “2025 IRP Financial Summary” appears to show
15 varying levels of upward pressure on the Company’s base rates under each scenario.
16 Moreover, it is not assured that the extraordinary load growth that the Company has
17 projected will actually result in downward pressure on rates, particularly for residential and
18 small commercial customers.

19

20 **Q. IS THERE CURRENTLY A HEIGHTENED LEVEL OF UNCERTAINTY?**

21 A. Yes. There is currently uncertainty about a number of items including environmental
22 regulations and economic conditions.

23

24 **Q. WHAT ARE SOME OF THE COMPANY’S ASSUMPTIONS THAT COULD BE**
25 **INCORRECT AND RESULT IN CUSTOMER RATES INCREASES?**

26 A. A number of assumptions could turn out to vary from the Company’s projections. The costs
27 of serving the additional load could come in higher than projected. The anticipated

1 revenues from adding the new large customers could come in lower or later than the
2 Company has projected. Additionally, there could be additional costs incurred that have
3 not yet been considered in the Company’s preliminary estimates. The Company’s
4 calculation above only covers 2026 – 2028 and not future years so the long-term financial
5 impact of serving new large load customers is not known at this time and could turn out to
6 vary significantly from the Company’s current expectations.

7
8 **Q. IS THERE A CONCERN THAT THE REQUESTS BEING MADE IN THE**
9 **COMPANY'S 2025 IRP COULD CONTRIBUTE TO HIGHER RATES FOR**
10 **RESIDENTIAL CUSTOMERS AND SMALL GENERAL SERVICE CUSTOMERS**
11 **IN THE COMPANY'S NEXT RATE CASE THAT IS SCHEDULED TO BE FILED**
12 **IN JULY 2025?**

13 A. Yes. Georgia Power is proposing to add several new large customers, including data
14 centers and other commercial and industrial customers. The Company has provided a
15 Ratepayer Impact Measure (“RIM” test) which purports to show that there would be overall
16 downward pressure on rates over the life of the respective resources that would need to be
17 added to serve the large amount of additional load.⁶ While some of the information
18 provided by the Company as a preliminary estimate shows the Company’s calculations of
19 a potential decrease for the typical residential customer in 2026 and 2028,⁷ Staff has not
20 seen analysis from the Company that projects out impacts in Class Cost of Service Study
21 (“COSS”) detail, such as showing expected impacts on residential customers and other
22 customer classes, from the cost of additional resources that would be added by the

⁶ The RIM test calculates whether an individual customer will generate enough revenue to cover their cost to serve. A RIM test does not measure the specific impact on other customers.

⁷ See, Trade Secret Attachment A to the Company’s supplemental response to STF-DEA-3-6, which is reproduced in Table 1 above.

1 Company to serve the additional amounts of new large commercial and industrial customer
2 load over the long term.

3
4 **Q. WHY ARE THERE CONCERNS WITH HOW THE SUBSTANTIALLY**
5 **INCREASED COSTS THAT WOULD BE INCURRED BY THE COMPANY TO**
6 **SERVE NUMEROUS NEW LARGE LOAD CUSTOMERS COULD AFFECT**
7 **RATES FOR OTHER CUSTOMERS?**

8 A. One problem with Georgia Power's analysis is that it is looking at the impact on customers
9 as a whole, rather than showing impacts on existing individual customer classes, such as
10 on residential and small business customers. Moreover, there are several assumptions
11 being made by the Company that could vary significantly from what actually happens over
12 the life of new assets. When the Company's new base rates are set in a rate case, rates are
13 set for each customer class. With reference to the prior COSS from the 2022 base rate case,
14 the projected substantial increase in kWh sales from the new data centers and other large
15 load customers and the related amounts of increased revenue would presumably be
16 accruing only to the large customer rate classes in an updated COSS that would be filed
17 with the Company's 2025 rate case. In an updated COSS, the increased revenues from
18 those new large load customers would presumably be credited only to the rate classes under
19 which those new customers are taking service in an updated COSS and not to other
20 customer classes. In a COSS, the assignment of cost is done using a variety of factors, not
21 just kWh sales to each customer class. Based on the Company's most recent cost of service
22 study from the Company's 2022 rate case, Staff estimates the majority of new large load
23 customer costs would be assigned to customers in a large commercial customer class. The
24 large commercial customer class with the data center customers would presumably see a
25 large increase in revenues and kilowatt-hours and could see a decrease in rates, if, as the
26 Company projects, the additional revenues from serving those new large load customers

1 exceed the allocated cost to serve those customers.

2

3 **Q. HOW COULD THE ALLOCATION OF NEW LARGE LOAD CUSTOMER**
4 **COSTS LEAD TO UPWARD PRESSURE ON RATES FOR CUSTOMER**
5 **CLASSES THAT ARE NOT RESPONSIBLE FOR THE DEMAND GROWTH?**

6 A. Some of the increased costs that are being incurred by the Company to serve the new large
7 load customers could be allocated to residential and small business customers which would
8 put upward pressure on their rates. Looking at the projected net revenue requirement
9 impacts on an overall basis, rather than considering how an updated COSS would allocate
10 the increased costs to individual customer classes, such as to residential customers, could
11 produce downward pressure on rates to certain classes, such as the large commercial and
12 industrial class, while producing upward pressure on rates to other classes, such as to
13 residential and small business customers. The problem for other rate classes, such as the
14 residential class, is that they could be assigned much of the new significantly increased
15 costs in the COSS filed in the Company's 2025 rate case, , but do not have the
16 corresponding additional (kilowatt) sales or revenue to offset the increased allocated costs
17 and, consequently, their rates could increase. Staff thus has concerns that the Company's
18 2025 IRP proposals, particularly with the costs projected to be incurred to serve the
19 extraordinary growth associated with adding numerous new large load customers could
20 result in upward pressure on residential and other customer rates in the 2025 rate case.

21

22 **Q. ARE THERE ALSO CONCERNS ABOUT POTENTIAL DELAYS IN THE**
23 **COMPANY'S RECEIPT OF REVENUES FROM ADDING THE NEW LARGE**
24 **LOAD CUSTOMERS?**

25 A. Yes. Staff has concerns that the increased revenues from the new large load customers may
26 materialize at lower levels or at a slower pace or both than has been projected by the

1 Company. Once costs to add additional generating and transmission resources to serve
2 the projected new large load customers are incurred, those costs, if allowed, would become
3 part of the Company's overall revenue requirement. If revenues from the new large load
4 customers materialize at lower levels or at a slower pace than projected by the Company,
5 Staff is concerned that it would put upward pressure on the rates of existing Georgia Power
6 ratepayers⁸.

7
8 **Q. IS IT GUARANTEED THAT ADDING THE LARGE AMOUNTS OF NEW**
9 **COMMERCIAL AND INDUSTRIAL CUSTOMER LOAD WOULD IN FACT PUT**
10 **DOWNWARD PRESSURE ON CUSTOMER RATES?**

11 A. No. While the Company projects that the additional revenues it expects from the large
12 amounts of new load could cover additional costs of serving that additional load, there is
13 no assurance that adding the large amounts of new commercial and industrial customer
14 load would result in rate reductions or downward pressure on rates in the next rate case.
15 Nor is there assurance that costs incurred relating to adding such large amounts of new load
16 and serving the new customers that are forecast by the Company would not result in
17 increased costs of providing electric utility service to current customers, thus resulting in
18 rate increases to the Company's current customers in the Company's next rate case. There
19 is a risk that the costs to serve the additional load could exceed the additional revenue that
20 the new load is projected by the Company to produce.

⁸ If all of the cost to serve large load customer is assigned to their customer class then the upward pressure on rates would only impact those large load customer rate classes and not other customer classes such as residential and small business.

1 **III. REGULATORY ACCOUNTING DEFERRALS**

2
3 **Q. WHAT IS A REGULATORY ACCOUNTING COST DEFERRAL?**

4 A. A regulatory accounting cost deferral basically involves deferring the recognition of costs
5 from the period in which such costs are incurred into a future period so the costs can be
6 addressed in a future rate case. Otherwise, costs must be recognized in the period incurred
7 and this would lower Company profits all else equal. Deferring cost to a future time period
8 would provide the Company the opportunity to increase rates to recover the cost from
9 ratepayers in a subsequent rate case.

10
11 **Q. UNDER THE COMMISSION'S ORDER IN GEORGIA POWER COMPANY'S**
12 **2022 RATE CASE, DOCKET NO. 44280, HOW ARE THE COMPANY'S**
13 **EARNINGS IN THE YEARS 2023, 2024 AND 2025 BEING REVIEWED?**

14 A. The Company's earnings in each year 2023, 2024 and 2025 are being reviewed in an
15 Annual Surveillance Report ("ASR") process that calculates the earned return on equity
16 ("ROE") and compares that to an ROE band of 9.5 percent to 11.9 percent that was
17 established in the Commission's order. The Company's current three-year rate plan also
18 provides that if the Company's earnings in a year exceeds the top end of the ROE band,
19 there are established provisions for the sharing of the excess earnings. If the Company
20 projects that its earnings would fall below the low end of the ROE band, it can petition for
21 rate relief. If earnings are within the established ROE band, i.e., within the "dead band,"
22 there is no sharing between Company investors and ratepayers. One of the expectations of
23 having the Company on a three-year rate case filing cycle, is that fluctuations of revenue
24 and expenses resulting in changes to net income to shareholders that is within the earnings
25 band would typically not require base rate modifications or entail the creation of new
26 regulatory assets. One goal of utility regulation is to simulate a competitive market

1 environment for the utility. In competitive markets businesses have the responsibility to
2 manage changes in revenues and costs resulting from changing market conditions. The
3 earnings band also provides the Company incentives to control costs and to maximize
4 profits.

5
6 **Q. WHAT IS THE EARNINGS BAND FROM THE COMPANY’S 2022 RATE CASE?**

7 A. The Company has earnings bandwidth within the ROE range of 9.5 percent to 11.9 percent
8 that was established in the Company’s most recent (2022) rate case, Docket 44280.

9
10 **Q. WHAT HAPPENS TO EARNINGS THAT ARE WITHIN THE BAND?**

11 A. To the extent that earnings are within the band, there is no sharing between investors and
12 ratepayers.

13
14 **Q. DO THE 24 ITEMS THAT THE COMPANY REQUESTED FOR COMMISSION
15 APPROVAL IN THE 2025 IRP INCLUDE SPECIFIC REQUESTS FOR NEW
16 REGULATORY ACCOUNTING DEFERRALS?**

17 A. No. The 24 items listed in the 2025 IRP on pages 4-6 do not appear to contain any specific
18 requests for Commission approval of new regulatory accounting deferrals.

19
20 **IV. ADDITIONAL SUM AMOUNTS**

21
22 **Q. WHAT ARE “ADDITIONAL SUM” AMOUNTS?**

23 A. Additional Sum amounts represent incremental revenue to Georgia Power tied to PPA
24 agreements. There is no capital investment made by the Company or incurred costs so the
25 Additional Sum revenue drops straight to the bottom line. Under traditional ratemaking the
26 Company makes capital investments in utility plant in order to provide reliable electric

1 utility service. The Commission allows the Company to earn a return on capital investment
2 that is included in utility rate base in order to compensate Company investors. In contrast,
3 the Company makes no capital investment when procuring capacity through PPAs but can
4 be allowed by the Commission a profit through an Additional Sum. The Additional Sum
5 amounts, once approved by the Commission, effectively function as additional revenue to
6 the Company which produces profits to shareholders. The revenues related to those
7 Additional Sums have historically been excluded from consideration in the reviews of the
8 Company's earnings and earnings sharing that have occurred in conjunction with the
9 reviews by Staff of the Company's Annual Surveillance Reports.

10
11 **Q. WHAT HAS THE COMPANY PROPOSED FOR ADDITIONAL SUM AMOUNTS**
12 **IN ITS 2025 IRP?**

13 A. Referring to the 24 items listed on pages 4-6 of the 2025 IRP for which the Company is
14 requesting Commission approval, the following items relate to Company requests for
15 Additional Sums:

16 3. The revised calculation of the additional sum collected through DSM programs
17 certified in the 2025 DSM Application, Docket No. 56003.

18 6. Approval of the levelized additional sum of \$4.00 / kilowatt ("kW") alternating
19 current ("AC") of the total capacity amount from new demand response and new DER
20 programs, including the large Customer Owned Resiliency Program, Solar Plus
21 Storage Pilot Program, and modified Customer Connected Solar Program ("CCSP").

22 17. The levelized additional sum of \$4.00 / kW-yr AC of the total capacity amount
23 from which renewable energy is procured from the Utility Scale and DG RFPs
24 proposed in this IRP, annually for the term of each PPA.

25
26 **Q. ARE OTHER STAFF PANELS ADDRESSING THE MERITS AND LEVELS OF**
27 **THOSE REQUESTS FOR ADDITIONAL SUM?**

28 A. Yes. The Staff Barber-Cooper-Spellman Panel is addressing Georgia Power's request No.
29 3 for a revised Additional Sum methodology related to DSM and Georgia Power's request

1 No. 6 for a \$4.00 / kW Additional Sum for the new demand response and new DER
2 programs. The Staff Barber-Kaduk-Bower Panel is addressing the Company's request No.
3 17 for a levelized \$4.00 / kW-year Additional Sum annually and for the term of each PPA
4 for renewable energy procured from the Utility Scale and DG RFPs.
5

6 **Q. WHAT ASPECTS OF THE COMPANY'S REQUESTS FOR ADDITIONAL SUMS**
7 **ARE YOU ADDRESSING?**

8 A. We address how the Georgia Code provides for Additional Sum amounts. We also address
9 the historical accounting, ratemaking and earnings treatment of the Additional Sum
10 amounts.
11

12 **Q. HOW DOES THE GEORGIA CODE PROVIDE FOR AN ADDITIONAL SUM?**

13 A. O.C.G.A. §46-3A-8, states that the Company is entitled to an Additional Sum, *as*
14 *determined by the Commission*, for purchased power resources based on the consideration
15 of certain factors which shall be considered by the Commission, such as lost revenues,
16 changed risks and equitable sharing of benefits between the Company and ratepayers in
17 determining the appropriate Additional Sum required to encourage long-term power
18 purchases. While the Georgia Code sets forth certain factors that the Commission must
19 consider in setting the Additional Sum, neither the Act nor Commission Orders set forth
20 any specific methodology or formula to calculate that additional sum.
21

22 **Q. WHAT FACTORS DOES O.C.G.A. §46-3A-8 INDICATE NEED TO BE**
23 **CONSIDERED?**

24 A. O.C.G.A. §46-3A-8 states as follows:

25 The approved or actual cost, whichever is less, of purchase of any certificated long-
26 term power purchase shall be recovered in rates by the utility, along with an additional
27 sum as determined by the commission to encourage such purchases. The commission

1 shall consider lost revenues, if any, changed risks, and an equitable sharing of benefits
2 between the utility and its retail customers.

3
4 **Q. IS IT STAFF’S UNDERSTANDING THAT THE COMMISSION MUST GRANT**
5 **GEORGIA POWER AN ADDITIONAL SUM ON ALL PPAS?**

6 A. No. An Additional Sum is supposed to "encourage" behavior.

7
8 **Q. IF THE WORD “SHALL” IN O.C.G.A. §46-3A-8 WERE TO BE INTERPRETED**
9 **TO REQUIRE AN ADDITIONAL SUM, HOW WOULD THAT AFFECT STAFF’S**
10 **RECOMMENDATION?**

11 A. The Company has argued in the past that §46-3A-8 requires the Commission to include an
12 Additional Sum, noting that O.C.G.A. §46-3A-8 uses the word "shall." As noted above,
13 while Staff disagrees that an additional sum is required on all PPAs, even under the
14 Company's interpretation, Staff’s understanding is that the Commission has the authority
15 to set the Additional Sum amount and could set that at something other than the \$4.00 /kW-
16 year that the Company is requesting.

17
18 **Q. WHAT ADDITIONAL SUM DID THE COMPANY RECEIVE IN THE 2023 IRP**
19 **UPDATE PROCEEDING?**

20 A. In the 2023 IRP Update, the Company received approval for an Additional Sum of
21 \$4.00/kW-year beginning in 2026 and for the remainder of the terms of the PPAs for certain
22 new capacity PPAs that were approved in that proceeding.

23
24 **Q. HOW HAVE ADDITIONAL SUM AMOUNTS THAT HAVE BEEN APPROVED**
25 **BY THE COMMISSION BEEN TREATED FOR RATEMAKING AND ANNUAL**
26 **SURVEILLANCE REPORT (“ASR”) PURPOSES?**

27 A. For both rate case and ASR purposes, the Additional Sum amounts provide revenue to the

1 Company but there is no related expense recorded in the Company's general ledger.⁹ In
2 Staff's view, the Additional Sum amounts provide additional revenue and profit to the
3 Company. Moreover, the Additional Sum amounts are removed in the ASRs so the profits
4 related to that additional pre-tax income has not been subject to sharing or with keeping
5 the Company's earnings above the minimum threshold approved in the 2022 rate case,
6 Docket No. 44280. In the ASRs, the Additional Sum amounts are reflected in a column
7 adjustment and are thus effectively removed from the consideration of whether the
8 Company's earned ROE is within or above the band.
9

10 **Q. DOES STAFF INTEND TO REVIEW IN THE UPCOMING RATE CASE**
11 **WHETHER THE ADDITIONAL SUM AMOUNTS SHOULD CONTINUE TO BE**
12 **EXCLUDED PROSPECTIVELY FROM EARNINGS REVIEWS?**

13 A. Yes. In the upcoming rate case, Staff intends to re-examine the issue of including the
14 additional sums in the earnings reviews on a going forward basis. If the additional sum is
15 increased, that would only increase the need to include it in earnings reviews.
16

17 **Q. IF NEW ADDITIONAL SUM AMOUNTS, OR CHANGES IN METHODOLOGY**
18 **THAT RESULTED IN HIGHER ADDITIONAL SUM AMOUNTS WERE TO BE**
19 **APPROVED IN THE 2025 IRP, WOULD THAT PUT ADDITIONAL UPWARD**
20 **PRESSURE ON RATES?**

21 A. Yes. New Additional Sum amounts or changes in the methodology that would produce
22 higher Additional Sums would provide additional pre-tax profits to the Company and
23 would become an additional cost to the Company's ratepayers when rates are being reset
24 in the 2025 rate case.

⁹ See, e.g., the Company's responses to STF-LA-2-20 and STF-LA-3-4 in the Company's 2022 IRP, which provide the Company's explanation. Both of those responses are included in Exhibit RS/JF-3.

1

2 **Q. DOES THE COMPANY INCLUDE THE ADDITIONAL SUM IN ITS ECONOMIC**
3 **EVALUATION OF THE CAPACITY PPAS?**

4 A. No, as indicated in the response to STF-LA-3-5 in the Company’s 2022 IRP.¹⁰

5

6 **V. PRODUCTION TAX CREDITS AND INVESTMENT TAX CREDITS**

7

8 **Q. DID THE INFLATION REDUCTION ACT, WHICH WAS SIGNED INTO LAW IN**
9 **2022 PROVIDE FOR FEDERAL INCOME TAX INCENTIVES PRODUCTION**
10 **TAX CREDITS AND INVESTMENT TAX CREDITS?**

11 A. Yes. The Inflation Reduction Act (“IRA”) provided opportunities for Investment Tax
12 Credits (“ITC”) and Production Tax Credits (“PTC”) that can benefit customers from the
13 deployment of battery storage systems (“BESS”) and solar generating resources.

14

15 **Q. REFERRING TO THE “2025 IRP FINANCIAL REVIEW” IN TECHNICAL**
16 **APPENDIX VOLUME 2, HAS THE COMPANY INCORPORATED ANY**
17 **FEDERAL INCOME TAX BENEFITS IN THOSE SCENARIOS?**

18 A. Yes. In its response to STF-LA-1-8(a),¹¹ the Company stated that:

19 ... the total annual revenue requirements include production tax credits (“PTCs”) and
20 investment tax credits (“ITCs”) for the generic expansion resources selected in each
21 of the sensitivities included in the Financial Review. The Company did not separately
22 calculate the amounts of PTCs and ITCs for each of these sensitivities. Rather, the
23 Company included the anticipated amounts of the PTCs and ITCs for generic
24 technologies in the capital cost calculation included in the expansion plan analyses
25 used in the Financial Review. The Company provided detailed PTC, ITC, and
26 technology cost assumptions in Table 2 of Technical Appendix 2 Resource Mix Study

¹⁰ A copy of that response is included in Exhibit RS/JF-3.

¹¹ A copy of that response is included in Exhibit RS/JF-4.

1 TRADE SECRET. The Aurora output files that include the capacity expansions for
2 each sensitivity were provided to Commission Staff on January 31, 2025, in the
3 workpapers for Technical Appendix 2 Resource Mix Study. STF-LA-1-8 Attachment
4 TRADE SECRET provides the NPV of tax credits by commercial operation date
5 (“COD”) year for each technology in the Mix Study that is eligible for tax credits (ITC,
6 PTC and 45Q). This information can be used to calculate the approximate total
7 amounts of tax credits for each sensitivity.

8
9 **Q. DOES THE COMPANY’S 2025 IRP ANTICIPATE ANY OTHER FEDERAL**
10 **INCOME TAX BENEFITS FOR RENEWABLE RESOURCES, BEYOND PTCS**
11 **AND ITCS?**

12 A. No, per the response to STF-LA-1-8(c).

13
14 **Q. DOES THE COMPANY ANTICIPATE ANY STATE INCOME TAX BENEFITS**
15 **FOR ANY OF THE YEARS SHOWN IN THE “2025 IRP FINANCIAL REVIEW”**
16 **FOR ANY OF THE YEARS SHOWN FOR ANY OF THE SCENARIOS?**

17 A. No, per the response to STF-LA-1-8(d).

18
19 **VI. ENVIRONMENTAL COMPLIANCE STRATEGY**

20
21 **Q. HAS THE COMPANY PRESENTED ITS ENVIRONMENTAL COMPLIANCE**
22 **STRATEGY (“ECS”)?**

23 A. Yes. The Company’s proposed ECS is presented in the 2025 IRP in Technical Appendix
24 Volume 1. Additional details for the CCR and CCR ARO are presented in Technical
25 Appendix Volume 2.

26
27 **Q. WHAT COMMISSION APPROVAL HAS THE COMPANY REQUESTED FOR**
28 **THE CAPITAL, O&M, AND CCR ARO COSTS AND ASSOCIATED MEASURES**
29 **TAKEN TO COMPLY WITH GOVERNMENT-IMPOSED ENVIRONMENTAL**

1 **MANDATES?**

2 A. In paragraph 13 at page 4 of the IRP Main Document, the Company presents the following
3 request for Commission approval :

4 13. The capital, O&M, and coal combustion residual asset retirement obligation
5 (“CCR ARO”) costs (but not yet the recovery of such costs) and associated measures
6 taken to comply with government-imposed environmental mandates, as specified in
7 the ECS in Technical Appendix Volume 1 and the Environmental Compliance Cost
8 Recovery (“ECCR”) and CCR ARO tables in the Selected Supporting Information
9 section of Technical Appendix Volume 2.

10

11 **Q. HAS THE COMPANY PROVIDED DETAILS FOR ITS PROJECTED ECCR**
12 **COSTS?**

13 A. Yes. A one-page summary is provided as Trade Secret information in Technical Appendix
14 Volume 2, at the ECCR tab, summarizing project-to-date costs through 2024 as presenting
15 projected costs for the years 2025 through 2028. Additional information was obtained from
16 the Company in response to discovery. The Company’s response to STF-LA-1-9¹² and its
17 TS-STF-LA-1-9 Attachment provide project-to-date costs through 2024 as well as
18 projected costs for the years, 2025 through 2028, by generating unit. The Company’s
19 response to STF-LA-1-15 and its TS-STF-LA-1-15¹³ Attachment provide projected capital
20 expenditures by component by plant for years 2025 through 2028. The Company’s
21 response to STF-LA-1-16 and its TS-STF-LA-1-16 Attachment¹⁴ provide projected
22 closures to Plant (i.e., Plant in Service) amounts for the ECCR by component by plant for
23 years 2025 through 2028. The Company’s response to STF-LA-1-17 and its TS-STF-LA-

¹² A copy of that response is included in Exhibit RS/JF-5.

¹³ A copy of that response is included in Exhibit RS/JF-5.

¹⁴ A copy of that response is included in Exhibit RS/JF-5.

1 1-17 Attachment¹⁵ provide projected O&M expenses for the ECCR by component by plant
2 for years 2025 through 2028. The Company's response to STF-LA-1-12 and the TS STF-
3 LA-1-12 Attachment¹⁶ includes summary level ECCR capital expenditure projections,
4 plant in service amount projections, and total projected O&M expenses for the year 2029.
5

6 **Q. WHAT TYPES OF COSTS ARE INCLUDED IN THE COMPANY'S PROJECTED**
7 **ECCR COSTS?**

8 A. The Company's projected ECCR costs include capital and O&M expenditures for
9 environmental control equipment such as scrubbers and Selective Catalytic Reduction
10 (SCR) equipment, baghouses, wastewater treatment, ash management, landfills, and other
11 controls.
12

13 **Q. HOW DOES THE COMPANY ACCOUNT FOR ECCR RELATED CAPITAL**
14 **EXPENDITURES?**

15 A. As explained in the Company's response to STF-LA-1-14:¹⁷

16 Capital expenditures are recorded to FERC account 107 (Construction Work in
17 Progress) prior to being placed in service, and once they are closed to plant in service,
18 as represented by closures to plant, they are recorded to FERC account 101 (Plant in
19 Service).
20

21 **Q. HAS THE COMPANY PROVIDED A PROJECTION OF ITS ECCR O&M**
22 **EXPENSE BY FERC ACCOUNT?**

23 A. Yes. The Company's response to STF-LA-1-14 included a TS Attachment STF-LA-1-14
24 showing the projected ECCR O&M expenses for each year, 2025 through 2028, by FERC

¹⁵ A copy of that response is included in Exhibit RS/JF-5.

¹⁶ A copy of that response is included in Exhibit RS/JF-5.

¹⁷ A copy of that response is included in Exhibit RS/JF-5.

1 account.

2

3 **Q. DOES THE COMPANY CONSIDER MULTIPLE COST ESTIMATES FOR ECCR**
4 **COMPLIANCE?**

5 A. The Company was asked in STF-LA-1-18¹⁸ whether the Company had more than one
6 estimate of the cost for the environmental projects listed in Technical Appendix Volume 2
7 for the ECCR. The Company’s response stated as follows:

8 The Company did not create separate estimates but rather considered compliance
9 options as they were evaluated. The resulting estimates are included in the
10 Environmental Compliance Strategy (“ECS”) and incorporated into the unit retirement
11 study scenarios. Following this analysis, the Company determines the most cost-
12 effective approach for each unit that meets regulatory requirements. The most
13 appropriate approach for each unit may not be the least cost option, all things held
14 equal, because of the unit-specific risks and requirements to comply and the need to
15 incorporate reliability considerations. Where appropriate, the Company continues to
16 look for alternative compliance options that are in the best interest of customers.

17 The development of the Company’s ECS first considers a regulatory review of current
18 and possible future local, state, regional, and federal environmental requirements.
19 Following the regulatory review, the Company evaluates the specific requirements for
20 each generating plant and/or unit, as well as availability and the timeline to implement
21 the control technology, to determine what control technology options are available to
22 comply. The feasible control options are evaluated based on technical performance,
23 reliability, operational flexibility, and capital and O&M cost impacts. These
24 evaluations can be developed over several years as the dynamic environmental
25 regulatory landscape changes (as shown by the Company’s ongoing strategy for ELG
26 compliance), and the Company undergoes an iterative process, both with industry
27 vendors and internally, to prepare the estimates provided in the ECCR table.

28 Please see the Company’s response to STF-LA-1-11 and STF-JKA-1-21 for estimates
29 and information used in the development of the ECCR table. Projects that are routine
30 to the plant are estimated based on prior experience and material quotes and contain
31 labor and material escalations.

¹⁸ A copy of that response is included in Exhibit RS/JF-5.

1
2 **Q. HAS THE COMPANY NOTED THAT THERE ARE SIGNIFICANT**
3 **UNCERTAINTIES WITH RESPECT TO SOME OF THE ENVIRONMENTAL**
4 **COMPLIANCE REQUIREMENTS?**

5 A. Yes. For example, the Direct Testimony of the McNelly-Mitchell Panel at page 10 uses
6 the term “uncertainty” in the Question on line 12, and a number of times in the answer,
7 including on lines 14 and 22, and then on line 26 that Company testimony mentions that
8 “until there is more certainty on the ultimate outcome.” Despite all of the uncertainty,
9 Georgia Power wants the Commission to approve its projected ECS plan and the related
10 capital, O&M and CCR ARO costs. In contrast, Staff believes that approval of costs in the
11 2025 IRP proceeding would be premature, and may result in having the Commission
12 approve costs that will not need to be incurred. Consequently, as described below, Staff
13 recommends that no approval of ECS plan costs occur at this time, and that the costs be
14 reviewed in the Company’s upcoming rate case.

15
16 **Q. HAS THE COMPANY’S ECCR TARIFF BEEN SUBJECT TO TRUE-UP?**

17 A. No. As indicated in the response to STF-LA-1-19,¹⁹ the ECCR tariff approved by the
18 Commission in the Company’s 2022 base rate case in Docket No. 44280 was not subject
19 to true-up.

20
21 **Q. HAS THE COMPANY MAINTAINED INFORMATION ON WHETHER IT HAS**
22 **OVER- OR UNDER-RECOVERED COSTS IN ITS ECCR TARIFF?**

23 A. No, as indicated in the response to STF-LA-1-19, because the ECCR was not subject to
24 true-up, the Company has not maintained an under- or over-recovery balance related to the

¹⁹ A copy of that response is included in Exhibit RS/JF-5.

1 ECCR.

2

3 **Q. ARE CONTINGENCY AMOUNTS PROJECTED BY THE COMPANY FOR THE**
4 **ECCR?**

5 A. Yes. As indicated in the response to STF-LA-1-20,²⁰ the \$958.1 million of total ECCR
6 capital expenditures projected for 2025-2028 include a collective contingency of
7 approximately \$141 million for environmental compliance strategy projects.

8

9 **Q. WHAT IS STAFF’S RECOMMENDATION IN THIS IRP CASE CONCERNING**
10 **THE COMPANY’S PROJECTED ECCR COSTS?**

11 A. Staff’s recommendation is that the Commission approve the Company’s ECCR plan as set
12 forth in the IRP and Technical Appendices and further detailed in the Company’s response
13 to STF-LA-1-15, STF-LA-1-16 and STF-LA-1-17, but not approve specific costs or cost
14 recovery at this time. Staff recommends that approval of specific costs and ECCR cost
15 recovery be addressed in the Company’s upcoming rate case.

16

17 **VII. COAL COMBUSTION RESIDUAL (“CCR”) COSTS**

18

19 **Q. HAS THE COMPANY PROVIDED DETAILS OF ITS CCR COSTS?**

20 A. Yes. Technical Appendix Volume 2 of the 2025 IRP includes a section that presents costs
21 related to the Company’s CCR Asset Retirement Obligation (“ARO”) for ash ponds and
22 landfills. Costs through December 31, 2024 amount to \$1.714 billion. Georgia Power
23 projects total costs of approximately \$7.064 billion, including \$2.562 billion for amount
24 projected for the year 2035 and beyond.

²⁰ A copy of that response is included in Exhibit RS/JF-5.

1

2 **Q. HOW HAS THE COMPANY ACCOUNTED FOR CCR COSTS?**3 A. As explained in the Company's response to STF-LA-1-26(c):²¹4 For the years 2022 through 2024, the CCR asset retirement obligations amounts were
5 recorded to FERC 230 Asset Retirement Obligation Liability and FERC 101 Plant in
6 Service. The same accounts are expected to be used for years 2025 and beyond.7 The Company's response to STF-LA-1-27²² provides the journal entries that Georgia
8 Power used to record 2024 amounts related to the CCR ARO. Additionally, the
9 Company's response to STF-LA-1-29²³ provided illustrative journal entries and dollar
10 amounts in a TRADE SECRET attachment for how the Company is accounting for CCR
11 costs at plants that were retired through December 31, 2024. The Company's response to
12 STF-LA-1-30²⁴ provided illustrative journal entries and dollar amounts in a TRADE
13 SECRET attachment for how the Company is accounting for CCR costs at plants that are
14 continuing to operate after their ash ponds are closed and remediated.

15

16 **Q. ARE THE COMPANY'S CCR ARO COSTS AND ACCOUNTING REVIEWED BY**
17 **THE COMPANY'S EXTERNAL AUDITOR?**18 A. Yes, the Company's external auditor, Deloitte, reviews Georgia Power's accounting and
19 financial reporting for the CCR ARO. In response to STF-LA-1-28,²⁵ the Company
20 provided several TRADE SECRET attachments containing correspondence between the
21 Company and its external auditor relating to the CCR ARO in 2024.

²¹ A copy of that response is included in Exhibit RS/JF-6.

²² A copy of that response is included in Exhibit RS/JF-6.

²³ A copy of that response is included in Exhibit RS/JF-6.

²⁴ A copy of that response is included in Exhibit RS/JF-6.

²⁵ A copy of that response is included in Exhibit RS/JF-6.

1 **Q. WHAT IS STAFF’S RECOMMENDATION CONCERNING THE COMPANY’S**
2 **CCR ARO COSTS?**

3 A. Staff’s recommends that the Commission not approve specific CCR costs or cost recovery
4 at this time. Staff recommends that approval of specific CCR costs and cost recovery be
5 addressed in the Company’s upcoming rate case.
6

7 **VIII. BENEFICIAL USE OF HARVESTED CCR**
8

9 **Q. HAS THE COMPANY UNDERTAKEN ATTEMPTS TO FIND BENEFICIAL**
10 **USES OF CCR?**

11 A. Yes. For example, as explained in the Company’s response to STF-LA-1-25(a):²⁶
12 In 2018, the Company invested \$2.5 million for the establishment of the Ash
13 Beneficial Use Center (“ABUC”) at Plant Bowen. These costs were recorded to
14 Federal Energy Regulatory Commission (“FERC”) account 506 in December 2018. In
15 December 2024, the Company invested another \$2.0 million for upgrades and general
16 maintenance to the ABUC, as well as supplemental funding for two pilot projects
17 expected to commence in 2025.
18

19 **Q. ARE ADDITIONAL COSTS FOR THE PLANT BOWEN ABUC EXPECTED FOR**
20 **2025 AND BEYOND?**

21 A. No. The Company’s response to STF-LA-1-25(b) indicates that: “No additional Georgia
22 Power funding for the ABUC is currently projected for the years 2025 and beyond.”
23

24 **Q. HAS ANY REVENUE BEEN REALIZED FROM HARVESTING CCR FOR**
25 **BENEFICIAL USE ASSOCIATED WITH THE ABUC IN 2023 OR 2024?**

26 A. No. The Company’s response to STF-LA-1-25(c) states that:

²⁶ A copy of that response is included in Exhibit RS/JF-7.

1 The Company has not recognized and does not anticipate any revenue from harvesting
2 CCR for beneficial use associated with the ABUC.

3
4 **Q. IS ANY REVENUE EXPECTED TO BE REALIZED FROM HARVESTING CCR**
5 **FOR BENEFICIAL USE ASSOCIATED WITH THE ABUC IN 2025 THROUGH**
6 **2028?**

7 A. No. The Company’s response to STF-LA-1-25(d) states that:
8 The Company does not anticipate to recognize any revenue from harvesting CCR for
9 beneficial use associated with the ABUC.

10
11 **Q. HOW IS THE ABUC MANAGED?**

12 A. The Company’s response to STF-LA-1-25(e) states that:
13 [BEGIN CONFIDENTIAL]

14 
15
16

17 [END CONFIDENTIAL]

18
19 **Q. HAS EPRI CONTRIBUTED FUNDING FOR THE ABUC?**

20 A. Yes. The Company’s response to STF-LA-1-25(f) states that:
21 EPRI has directly funded \$125,000 which included an initial investment toward
22 construction of the ABUC facility as well as to support ongoing research at ABUC.
23 See STF-LA-1-25 Attachment for details.

24
25 **Q. HAS THE COMPANY RECOGNIZED AMOUNTS FROM BENEFICIAL USE IN**
26 **2023 AND 2024?**

27 A. Yes. The Company’s response to STF-LA-1-25(c) states that:
28 During years 2023 and 2024 the Company did recognize the following amounts from
29 harvesting CCR for beneficial use. Harvesting for response to this question and STF-

1 LA-1-25 (d) is defined as CCR removed from ash ponds or CCR landfills for
2 beneficial use.

3 Sales resulting from removal of stored coal ash and gypsum for beneficial use is
4 applied to offset Georgia Power's projected [CCR ARO] costs.

5 The Company's response included a TRADE SECRET table identifying the amounts for
6 2023 and 2024.

7

8 **Q. DOES THE COMPANY EXPECT TO RECOGNIZE AMOUNTS FROM**
9 **BENEFICIAL USE IN THE YEARS 2025 THROUGH 2028?**

10 A. Yes. The Company's response to STF-LA-1-25(d) states that:

11 The Company anticipates the following sales from harvesting CCR for beneficial use
12 for years 2025 through 2028. Actual results may vary from these projections in the
13 future based on factors including but not limited to weather, plant operations,
14 beneficial use market trends, and supply chain and transportation factors.

15 Projected sales resulting from removal of stored coal ash and gypsum for beneficial
16 use is applied to offset Georgia Power's projected CCR ARO costs.

17 The Company's response included a TRADE SECRET table identifying the amounts for
18 each year, 2025 through 2028.

19

20 **Q. HOW ARE PROJECTED SALES FROM THE REMOVAL OF STORED COAL**
21 **ASH AND GYPSUM REFLECTED BY THE COMPANY FOR PURPOSES OF ITS**
22 **CCR ARO COSTS?**

23 A. As noted above, and stated in the Company's response to STF-LA-1-26,²⁷ projected sales
24 resulting from removal of stored coal ash and gypsum for beneficial use is applied to offset
25 Georgia Power's projected CCR ARO costs.

26

²⁷ A copy of that response is included in Exhibit RS/JF-6.

1 **IX. EXTENSION OF PLANT SCHERER UNIT 3 AND PLANT GASTON UNITS 1-4**
2 **AND A BEYOND DECEMBER 31, 2028**

3

4 **Q. WHAT HAS THE COMPANY REQUESTED FOR THE EXTENSION OF**
5 **GENERATING PLANT OPERATION DATES?**

6 A. At page 5 of the IRP Main Document, in item 7, the Company presents this request for
7 Commission approval:

8 7. Extended operation of Plant Scherer Unit 3 and Plant Gaston Units 1-4 and A
9 beyond December 31, 2028, as described in Chapter 8.

10

11 **Q. WHAT ARE THE CURRENT RETIREMENT DATES FOR PLANT SCHERER**
12 **THAT ARE USED FOR THE COMPANY'S DEPRECIATION RATES?**

13 A. As indicated in the Company's response to STF-LA-1-38,²⁸ the Depreciation Study
14 Retirement Date for Plant Scherer Unit 3 is 2028, as approved by the Commission in
15 Docket No. 44280.

16

17 **Q. OTHER THINGS BEING EQUAL, WHAT WOULD BE THE EXPECTED**
18 **RESULT ON DEPRECIATION EXPENSE FROM EXTENDING THE**
19 **ESTIMATED RETIREMENT DATE?**

20 A. Other things being equal, the expected result from extending the estimated retirement date
21 would be to lower depreciation expense because the remaining net plant in service cost
22 would be subsequently depreciated over a longer period.

23

24 **Q. SHOULD THE IMPACT OF ANY GENERATING PLANT RETIREMENT DATE**
25 **EXTENSIONS THAT ARE APPROVED IN THE 2025 IRP ON DEPRECIATION**

²⁸ A copy of that response is included in Exhibit RS/JF-8.

1 **EXPENSE BE REVIEWED IN THE COMPANY’S UPCOMING RATE CASE?**

2 A. Yes. The Company’s upcoming rate case is the proper forum rather than this IRP
3 proceeding for reviewing impacts on depreciation expense from any generating plant
4 retirement date extensions that are approved in the 2025 IRP.

5

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

7 A. Yes, it does.

EXHIBIT__(RCS-1)

Exhibit_(RCS-1)
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, Barbados, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Puerto Rico, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA	
&76-18793AA	
85-53476AA	
& 85-534785AA	
U-8091/U-8239	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
TR-85-179	
85-212	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
ER-85646001	Consumers Power Company - Gas Refunds (Michigan PSC)
& ER-85647001	United Telephone Company of Missouri (Missouri PSC)
850782-EI & 850783-EI	Central Maine Power Company (Maine PSC)
R-860378	
R-850267	New England Power Company (FERC)
851007-WU & 840419-SU	Florida Power & Light Company (Florida PSC)
G-002/GR-86-160	Duquesne Light Company (Pennsylvania PUC)
7195 (Interim)	Pennsylvania Power Company (Pennsylvania PUC)
87-01-03	Florida Cities Water Company (Florida PSC)
87-01-02	Northern States Power Company (Minnesota PSC)
	Gulf States Utilities Company (Texas PUC)
	Connecticut Natural Gas Company (Connecticut PUC))
	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
U-87-47	Anchorage Water and Wastewater Utility (Alaska PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102	
& E-1032-88-102	
89-0033	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
U-89-2688-T	Illinois Bell Telephone Company (Illinois CC)
R-891364	Puget Sound Power & Light Company (Washington UTC))
F.C. 889	Philadelphia Electric Company (Pennsylvania PUC)
Case No. 88/546	Potomac Electric Power Company (District of Columbia PSC)
	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628	Duquesne Light Company, et al, plaintiffs, against Gulf+Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
	Florida Power & Light Company (Florida PSC)
890319-EI	Gulf Power Company (Florida PSC)
891345-EI	Jersey Central Power & Light Company (BPU)
ER 8811 0912J	Hawaiian Electric Company (Hawaii PUCs)
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R-901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
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91-174	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
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U-91-091	Anchorage Telephone Utility (Alaska PUC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
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92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC)
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
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95-03-01	Southern New England Telephone Company (Connecticut PUC)
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94-996-EL-AIR	Ohio Power Company (Ohio PUC)
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E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC) Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
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94-10-45	Southern New England Telephone Company (Connecticut PUC)
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96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
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97-65	Application of Delmarva Power & Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
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Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
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T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)

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99-03-36	Connecticut Light & Power (Connecticut OCC)
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14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
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99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
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02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)

01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
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U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-84	ACS of Fairbanks dba Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-82	ACS of Anchorage dba Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
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04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
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Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
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Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
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06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
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E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
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PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
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08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
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G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
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09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
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Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
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W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)

09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)
2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, IHnc. (Arizona CC)
E-01773A-09-0472	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
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10-0713-E-PC Docket No. 31958	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
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10-0699-E-42T	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0920-W-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
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10-268-EL FAC et al.	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
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G-01551A-10-0458	Hawaiian Electric Company, Inc. (Hawaii PUC)
10-KCPE-415-RTS	Southwest Gas Corporation (Arizona CC)
PUE-2011-00037	Kansas City Power & Light Company – Remand (Kansas CC)
R-2011-2232243	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
U-11-100	Pennsylvania-American Water (Pennsylvania PUC)
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PSC Docket No. 10-247	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
G-04204A-11-0158	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
E-01345A-11-0224	UNS Gas, Inc. (Arizona Corporation Commission)
UE-111048 & UE-111049	Arizona Public Service Company (Arizona CC)
Docket No. 11-0721	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
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Cause No. 44075	Tidewater Utilities, Inc. (Delaware PSC)
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11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
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11-281-EL-FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)
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12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
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12-0511 & 12-0512	North Shore Gas Company and The Peoples Gas Light and Coke Company (Illinois CC)
E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
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Cause No. 43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 36498	Georgia Power Company (Georgia PSC)
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Docket No. 13-0192	Ameren Illinois Company (Illinois CC)
12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
R-2013-2355276	Pennsylvania-American Water Company (Pennsylvania PUC)
Formal Case No. 1103	Potomac Electric Power Company (District of Columbia PSC)
U-13-007	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
12-2881-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 3 (Ohio PUC)
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UM 1633	Investigation into Treatment of Pension Costs in Utility Rates (Oregon PUC)
13-1892-EL FAC	Financial Audit of the FAC and AER of the Ohio Power Company – Audit I (Ohio PUC)
E-04230A-14-0011 & E-01933A-14-0011	Reorganization of UNS Energy Corporation with Fortis, Inc. (Arizona CC)
14-255-EL RDR	Regulatory Compliance Audit of the 2013 DIR of Ohio Power Company (Ohio PUC)
U-14-001	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
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PUE-2014-00026	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
14-0702-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
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R-2014-2428742	West Penn Power Company (Pennsylvania PUC)
R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
R-2014-2428744	Pennsylvania Power Company (Pennsylvania PUC)
R-2014-2428745	Metropolitan Edison Company (Pennsylvania PUC)

Cause No. 43114-IGCC-12/13 14-1152-E-42T	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission) Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
WS-01303A-14-0010 2014-000396 15-03-45	EPCOR Water Arizona, Inc. (Arizona CC) Kentucky Power Company (Kentucky PSC) Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
A.14-11-003 U-14-111 2015-UN-049 15-0003-G-42T PUE-2015-00027 Docket No. 2015-0022	San Diego Gas & Electric Company (California PUC) ENSTAR Natural Gas Company (Regulatory Commission of Alaska) Atmos Energy Corporation (Mississippi PSC) Mountaineer Gas Company (West Virginia PSC) Virginia Electric and Power Company (Commonwealth of Virginia SCC) Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company Limited, and NextEra Energy, Inc. (Hawaii PUC)
15-0676-W-42T 15-07-38	West Virginia-American Water Company (West Virginia PSC) Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
15-26	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Massachusetts DPU)
15-042-EL-FAC	Management/Performance and Financial Audit of the FAC and Purchased Power Rider for Dayton Power and Light (Ohio PUC)
U-15-016	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
2015-UN-0080 Docket No. 15-00042 WR-2015-0301/SR-2015-0302 U-15-089, U-15-091,& U-15-092	Mississippi Power Company (Mississippi PSC) B&W Pipeline, LLC (Tennessee Regulatory Authority) Missouri American Water Company (Missouri PSC) Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 16-00001	Kingsport Power Company d/b/a AEP Appalachian Power (Tennessee Regulatory Authority)
PUE-2015-00097 15-1854-EL-RDR	Virginia-American Water Company (Commonwealth of Virginia SCC) Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
P-15-014 P-15-020 U-15-127 through U-15-138 Docket No. 40161 Formal Case No. 1137 160021-EI, et al. R-2016-2537349 R-2016-2537352 R-2016-2537355 R-2016-2537359 16-0717-G-390P 15-1256-G-390P (Reopening)/16-0922-G-390P 16-0550-W-P CEPR-AP-2015-0001 E-01345A-16-0036 Docket No. 4618 Docket No. 46238	PTE Pipeline LLC (Regulatory Commission of Alaska) Swanson River Oil Pipeline, LLC (Regulatory Commission of Alaska) Dyon Utilities, LLC (Regulatory Commission of Alaska) Georgia Power Company – Integrated Resource Plan (Georgia PSC) Washington Gas Light Company (District of Columbia PSC) Florida Power Company (Florida PSC) Metropolitan Edison Company (Pennsylvania PUC) Pennsylvania Electric Company (Pennsylvania PUC) Pennsylvania Power Company (Pennsylvania PUC) West Penn Power Company (Pennsylvania PUC) Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
U-16-066 Case No. 2016-00370	Mountaineer Gas Company (West Virginia PSC) West Virginia-American Water Company (West Virginia PSC) Puerto Rico Electric Power Authority (Puerto Rico Energy Commission) Arizona Public Service Company (Arizona CC) Providence Water Supply Board (Rhode Island PUC) Joint Report and Application of Oncor Electric Delivery Company LLC and NextEra Energy Inc. (Texas State Office of Administrative Hearings; Texas PUC) ENSTAR Natural Gas Company (Regulatory Commission of Alaska) Kentucky Utilities Company (Kentucky PSC)

Case No. 2016-00371	Louisville Gas and Electric Company (Kentucky PSC)
P-2015-2508942	Metropolitan Edison Company (Pennsylvania PUC)
P-2015-2508936	Pennsylvania Electric Company (Pennsylvania PUC)
P-2015-2508931	Pennsylvania Power Company (Pennsylvania PUC)
P-2015-2508948	West Penn Power Company (Pennsylvania PUC)
E-04204A-15-0142	UNS Electric, Inc. (Arizona CC)
E-01933A-15-0322	Tucson Electric Power Company (Arizona CC)
UE-170033 & UG-170034	Puget Sound Energy, Inc. (Washington UTC)
Case No. U-18239	Consumers Energy Company (Michigan PSC)
Case No. U-18248	DTE Electric Company (Michigan PSC)
Case No. 9449	Merger of AltaGas Ltd. and WGL Holdings (Maryland PSC)
Formal Case No. 1142	Merger of AltaGas Ltd. and WGL Holdings (District of Columbia PSC)
Case No. 2017-00179	Kentucky Power Company (Kentucky PSC)
Docket No. 29849	Georgia Power Plant Vogtle Units 3 and 4, VCM 17 (Georgia PSC)
Docket No. 2017-AD-112	Mississippi Power Company (Mississippi PSC)
Docket No. D2017.9.79	Montana-Dakota Utilities Co. (Montana PSC)
SW-01428A-17-0058 et al	Liberty Utilities (Litchfield Park Water & Sewer) Corp. (Arizona CC)
U-18-021 & U-18-033	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 4800	Suez Water Rhode Island Inc. (Rhode Island PUC)
General Order No. 236.1	In the Matter of the Effects on Utilities of the 2017 Tax Cuts and Jobs Act (West Virginia PSC)
20180047-EI	Duke Energy Florida, LLC. (Florida PSC)
20180046-EI	Florida Power & Light Company (Florida PSC)
20180048-EI	Florida Public Utilities Company – Electric (Florida PSC)
20180052-GU	Florida Public Utilities Company – Indiantown (Florida PSC)
20180054-GU	Florida Division of Chesapeake Utilities Corporation (Florida PSC)
20180051-GU	Florida Public Utilities Company – Gas Division (Florida PSC)
20180053-GU	Florida Public Utilities Company - Fort Meade (Florida PSC)
Cause No. 45032 S4	Indiana American Water Company, Inc. Phase 2 (Indiana Utility Regulatory Commission)
Docket No. D2018.1.6	Montana-Dakota Utilities Co. (Montana PSC)
Docket No. D2018.4.24	NorthWestern Energy (Montana PSC)
Docket No. D2018.4.22	Montana-Dakota Utilities Co. (Montana PSC)
18-0573-W-42T & 18-0576-S-42T	West Virginia-American Water Company (West Virginia PSC)
18-0646-E-42T & 18-0645 E-D	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
18-0049-GA-ALT, 18-0298-GA-AIR, & 18-0299-GA-ALT	Vectren Energy Delivery of Ohio, Inc. (Ohio PUC)
R-2018-3003558, R-2018-3003561	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
Cause No. 45142	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
U-18-043	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
T-03214-17-0305	Citizens Telecommunications Company of The White Mountains, Inc. d/b/a Frontier Communications of The White Mountains (Arizona CC)
Docket No. D2018.9.60	Montana-Dakota Utilities Co. (Montana PSC)
Docket No. 4890	Narragansett Bay Commission (Rhode Island PUC)
PUR-2018-00131	Columbia Gas of Virginia (Virginia SCC)
EL18-152-000	Louisiana PSC v. System Energy Resources, Inc. and Entergy Services, Inc. (FERC)
PUR-2018-00175	Virginia-American Water Company (Virginia SCC)

A-2018-3006061, A-2018-3006062 and A-2018-3006063	Aqua America, Inc., Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, Peoples Gas Company LLC (Pennsylvania PUC)
Docket No. D2018.2.12	NorthWestern Energy (Montana PSC)
Docket No. 42310	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
U-18-102	Municipality of Anchorage d/b/a Municipal Light & Power Department (Regulatory Commission of Alaska)
PUC Docket No. 49494	AEP Texas, Inc. (Texas PUC)
Application 18-12-009	Pacific Gas and Electric Company (California PUC)
19-0316-G-42T	Mountaineer Gas Company (West Virginia PSC)
U-19-020	Chugach Electric Association, Inc. and Municipality of Anchorage d/b/a Municipal Light & Power Department (Regulatory Commission of Alaska)
19-0051-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
A-2018-3006061, A-2018-3006062, and A-2018-3006063	Joint Application of Aqua America, Inc., Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, and Peoples Gas Company LLC (Pennsylvania PUC)
ER-18-1182-001	System Energy Resources, Inc. (FERC)
E-01933A-19-0028	Tuscon Electric Power Company (Arizona CC)
G-01551A-19-0055	Southwest Gas Corporation (Arizona CC)
2018-UN-205	Entergy Mississippi, LLC (Mississippi PSC)
W-03039A-17-0295, W-03039A-19-0092, and WS-01303A-19-0092	Brooke Water, LLC and EPCOR Water Arizona (Arizona CC)
Docket No. 4975	Block Island Utility District d/b/a Block Island Power Company (Rhode Island PUC)
A-2019-3014248	Pennsylvania-American Water Company and Wastewater System Assets of Kane Borough (Pennsylvania PUC)
Docket No. 4994	Providence Water Supply Board (Rhode Island PUC)
19-0791-GA-ALT	Plant in Service and Capital Spending Prudence Audit of Duke Energy Ohio (Ohio PUC)
U-19-070/U-19-071/ U-19-087/U-19-088	Golden Heart Utilities, Inc. and College Utilities Corporation (Regulatory Commission of Alaska)
Docket No. 42516	Georgia Power Company (Georgia PSC)
20200070-EI	Gulf Power Company (Florida PSC)
20200071-EI	Florida Power & Light Company (Florida PSC)
20200092-EI	Florida Power & Light Company and Gulf Power Company (Florida PSC)
20-GREC-01	Fitchburg Gas and Electric Light Company d/b/a Unitil (Massachusetts DPU)
20-GREC-03	Boston Gas Company and Colonial Gas Company d/b/a National Grid (Massachusetts DPU)
20-GREC-04	Liberty Utilities (New England Natural Gas Company) Corp d/b/a Liberty Utilities (Massachusetts DPU)
PUR-2020-00015	Appalachian Power Company (Virginia SCC)
20-0414-G-390P	Hope Gas, Inc. dba Dominion Energy West Virginia (West Virginia PSC)
Cause No. 45032-S16	Hamilton Southeastern Utilities, Inc. (Indiana URC)
2019.1.101	NorthWestern Energy (Montana PSC)

A-2019-3015173	Aqua Pennsylvania Wastewater Inc. and Wastewater System Assets of the Delaware County Regional Water Quality Control Authority (Pennsylvania PUC)
R-2020-3019369 and R-2020-3019371 2020.06.076 P-20-005 2020.05.055 2020.05.066 PUR-2020-00169 20-0746-G-42T	Pennsylvania American Water Company (Pennsylvania PUC) Montana-Dakota Utilities Co. (Montana PSC) Cook Inlet Pipeline LLC (Regulatory Commission of Alaska) Montana-Dakota Utilities Co. (Montana PSC) NorthWestern Energy (Montana PSC) Virginia Electric and Power Company (Virginia SCC) Hope Gas, Inc., d/b/a Dominion Energy West Virginia (West Virginia PSC)
20-553-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Rider of the Dayton Power and Light Company (Ohio PUC)
E-01345A-19-0236 U-20-012	Arizona Public Service Company (Arizona CC) Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
Docket No. 20-01-31	The Southern New England Telephone Company d/b/a Frontier Communications of Connecticut (SNET) (Connecticut PURA)
P-2020-3021191 A-2021-3026523, A-2021-3026515, and A-2021-3026522	Peoples Natural Gas Company LLC (Pennsylvania PUC)
A-2021-3026794 and A-2021-3026796	Joint Application of Veolia Environnement S.A., Veolia North America, Inc., SUEZ S.A., SUEZ Water Pennsylvania Inc. and SUEZ Water Bethel Inc. (Pennsylvania PUC)
A-2021-3026774 and A-2021-3026775	Joint Application of Peoples Natural Gas Company LLC and Peoples Gas Company (Pennsylvania PUC)
A-2021-3024267 R-2021-3027385 and R-2021-3027386	Joint Application of Aqua Pennsylvania Inc., and Aqua Pennsylvania Wastewater Inc. (Pennsylvania PUC) Aqua Pennsylvania Wastewater Inc. (Pennsylvania PUC)
21-0595-WW-AIR 21-0596-ST-AIR 21-0369-W-42T U-21-058	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC) Aqua Ohio, Inc. (Ohio PUC) Aqua Ohio Wastewater, Inc. (Ohio PUC) West Virginia-American Water Company (West Virginia PSC) Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
E-01345A-21-0056	Fuel and Purchased Power Audit of Arizona Public Service Company (Arizona CC)
SW-20445A-20-0214 et al PUR-2021-00058 U-21-070/U-21-071	Global Water Resources, Inc. (Arizona CC) Virginia Electric and Power Company (Virginia SCC) Golden Heart Utilities, Inc. and College Utilities Corporation (Regulatory Commission of Alaska)
U-22-001	Railbelt Reliability Council for Certification of an Electric Reliability Organization (Regulatory Commission of Alaska)
Docket No. 44160 22-620-GA-RDR	Georgia Power Company Integrated Resource Plan (Georgia PSC) Plant in Service and Capital Spending Prudence Audit of Vectren Energy Delivery of Ohio, Inc. d/b/a CenterPoint Energy Ohio (Ohio PUC)
PUR-2021-00255 RP19-3-003 22-0304-E-P	Virginia-American Water Company (Virginia SCC) El Paso Natural Gas Company, LLC (FERC) Appalachian Power Company and Wheeling Power Company (West Virginia PSC)

R-2022-3031672 and R-2022-3031673 22-0294-G-PC	Pennsylvania-American Water Company (Pennsylvania PUC) Hope Gas, Inc., dba Dominion Energy West Virginia and Hope Gas Holdings (West Virginia PSC)
G-01551A-21-0368 2022-06-064 U-21-088, U-21-089, U-22-006, U-2-007, U-22-008, U-22-009	Southwest Gas Corporation (Arizona CC) NorthWestern Energy (Montana PSC)
20220067-GU	Sand Point Generating, LLC, North Slope Generating, LLC, TDX Manley Generating, LLC, TDX North Slope Generating, LLC, Sand Point Generating, LLC, TDX ADAK Generating, LLC. (Regulatory Commission of Alaska)
PUR-2020-00015 U-22-029	Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company – Fort Meade, and Florida Public Utilities Company – Indiantown Division (Florida PSC)
22-0393-E-ENEC	Appalachian Power Company – Remand (Virginia SCC)
E-01773A-21-0298 Docket No. 44280 FTC-01/2021-BL&P- RRA-20211004	Golden Valley Electric Association, Inc. (Regulatory Commission of Alaska)
U-22-002 and U-22-003	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
A-2019-3015173	Arizona Electric Power Cooperative, Inc. (Arizona CC)
2022.07.078 A.22-05-016 2022-UN-86/2022-UN-087 E-01933A-22-0107 A-2022-3035298, A-2022-3035299, A-2022-3035490, A-2022-3035492	Georgia Power Company (Georgia PSC)
PUR-2022-00052 U-22-078	Barbados Light & Power Company Limited (Barbados Fair Trading Commission)
U-22-081 22-47-WW E-01345A-22-0144 E-04204A-22-0251 PUR-2023-00002 22-1094-WW-AIR 22-1096-ST-AIR A-2022-3037047, et al.	Municipality of Anchorage d/b/a Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
PUR-2023-00067 and PUR-2023-00112	Aqua Pennsylvania Wastewater Inc. and Wastewater System Assets of the Delaware County Regional Water Quality Control Authority - Remand (Pennsylvania PUC)
Docket No. 54634	NorthWestern Energy (Montana PSC)
	San Diego Gas & Electric Company (California PUC)
	Great River Utility Operating Company, LLC (Mississippi PSC)
	Tucson Electric Power Company (Arizona CC)
	Manwalamink Water Company, Manwalamink Sewer Company, NextEra Water Pennsylvania, LLC (Pennsylvania PUC)
	Virginia Natural Gas, Inc. (Virginia SCC)
	Alaska Electric Light & Power Company (Regulatory Commission of Alaska)
	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
	Narragansett Bay Commission (Rhode Island PUC)
	Arizona Public Service Company (Arizona CC)
	UNS Electric, Inc. (Arizona CC)
	Appalachian Power Company (Virginia SCC)
	Aqua Ohio, Inc. (Ohio PUC)
	Aqua Ohio Wastewater, Inc. (Ohio PUC)
	Pennsylvania-American Water Company, Butler Area Sewer Authority (Pennsylvania PUC)
	Virginia Electric and Power Company d/b/a Dominion Energy Virginia (Virginia SCC)
	Southwestern Public Service Company (Texas PUC)

23-0089-EL-RDR	Duke Energy Ohio, Inc. (Ohio PUC)
23-0280-G-42T	Mountaineer Gas Company (West Virginia PSC)
2022-0208	Kauai Island Utility Cooperative (Hawaii PUC)
PUR-2023-00101	Virginia Electric and Power Company d/b/a Dominion Energy Virginia (Virginia SCC)
23-0383-W-42T and	
23-0384-S-42T	West Virginia-American Water Company (West Virginia PSC)
23-0460-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
R-2023-3043189&	
R-2023-3043190	Pennsylvania-American Water Company (Pennsylvania PUC)
U-23-047/U-23-048	Chugach Electric Association (Regulatory Commission of Alaska)
U-23-054	Alaska Power Company (Regulatory Commission of Alaska)
U-23-065 through U-23-073	Alaska Waste (Regulatory Commission of Alaska)
T-03214A-23-0250	Citizens Telecommunications of the White Mountains, Inc., dba Frontier Communications of the White Mountains (Arizona CC)
PUR-2023-00194	Virginia-American Water Company (Virginia SCC)
G-01551A-23-0341	Southwest Gas Corporation (Arizona CC)
PUR-2024-00024	Appalachian Power Company (Virginia SCC)
R-2024-3047822 &	
R-2024-3047824	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
U-24-005/U-24-006	Municipality of Anchorage d/b/a Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
24-14-EL	Pascoag Utility District (Rhode Island PUC)
2022-0140	Hawaii Water Service Company, Inc. (Hawaii PUC)
24-0185-EL-RDR	AEP Ohio Company, d/b/a AEP-Ohio (Ohio PUC)
20240068-WS	Sunshine Water Services Company (Florida PSC)
W-02074A-23-0337,	
W-02465A-23-0338,	
WS-02060A-23-0339,	
WS-02676A-23-0340,	
WS-02676A-24-0029,	
W-02074A-24-0030,	
W-02465A-24-0031, and	
WS-02060A-24-0033	Liberty Utilities (Arizona CC)
2024.08.088	NorthWestern Energy, Energy West Montana, Inc., and Cut Bank Gas Company (Montana PSC)
2024.05.053	NorthWestern Energy (Montana PSC)
2024-0158	The Gas Company, LLC dba Hawaii Gas (Hawaii PUC)

EXHIBIT __ (JRF-1)

Exhibit__(JRF-1)

Mr. Forsythe received a Bachelor of Science degree in Accounting from Kean University in May 2017. In January 2019, he received a Master of Science degree in Accounting from Kean University.

From December 2020 to June 2022 Mr. Forsythe worked as a Rate Analyst for the New Jersey Board of Public Utilities. His duties included rate design and accounting.

In July 2022, Mr. Forsythe started as a Utilities Analyst for the Electric Unit at the Georgia Public Service Commission. During Mr. Forsythe's time at the Commission, he participated in Docket No. 44280, Georgia Power Company's 2022 Rate Case; Docket No. 29849, Georgia Power Company's Application to Adjust Rates to Include Reasonable and Prudent Plant Vogtle Units 3 and 4 Cost; Docket No. 44902 Georgia Power Company's Fuel Cost Recovery(FCR) Application (FCR-26); Docket No. 42310, Li-ion Battery Pilot; Docket No. 42516, Georgia Power Company's 2022 Annual Surveillance Report; Docket No. 44280, Georgia Power Company's 2023 Annual Surveillance Report; Docket No. 55268 Georgia Power Company's 2029-2031 All Source Capacity Request for Proposal; Docket No. 55338, Georgia Power Company's Application for Financing Authority, Docket No. 55378, Georgia Power Company's 2023 Integrated Resource Plan Update.

EXHIBIT__(RS/JF-2)

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-7

Question:

Refer to the tables on pages 2 through 14 of 14.

- a.** For each scenario shown in pages 2 through 14 of 14 for each of the amounts shown in the column “Total Annual Revenue Requirement” show in detail how such amounts were calculated, including details for each rate base component, each operating income component, the return component, income taxes, and how net operating incomes were grossed-up for the revenue requirement amounts. Include Excel files with formulas intact.
- b.** Explain what the Real Levelized Average rates represent.
- c.** Why do the Real Levelized Average rates vary from year to year?
- d.** What are the “Levelized Revenue Requirements”?
- e.** Why do the “Levelized Revenue Requirements” vary from year to year?
- f.** For each scenario shown in pages 2 through 14 of 14 what are the projected annual revenue requirements without any levelization? Provide calculations in Excel.
- g.** Was any discount rate used on the tables on pages 2 through 14 of 14 for any of the columns? If so, identify what discount rate(s) was/(were) used and provide the non-discounted amounts to which the discount rate(s) were applied. Also, show in Excel with formulas intact, how the discount rates were applied.
- h.** Refer to the tables on pages 2 through 14 of 14. Which columns represent net present values?
- i.** Refer to the tables on pages 2 through 14 of 14. Which columns represent nominal non-discounted dollars?
- j.** Refer to the tables on pages 2 through 14 of 14. Do any of the amounts in the “Total Annual Revenue Requirement” columns for years 2026, 2027 and 2028 represent the Company’s current best estimates of the rate case revenue requirement increases for any of the scenarios? If not, explain fully why not. If so, which specific items on pages 2 through 14 represent the Company’s current best estimates of the rate case revenue requirement increases for years 2026, 2027 and 2028? Explain fully.

Georgia Power Company
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2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

k. For the 2025 rate case expected to follow the 2025 IRP, does the Company expect that it will be requesting levelized revenue amounts that are based on amounts for any years beyond 2026-2028? If so, please explain.

Response:

a. Please see STF-LA-1-1 Attachment TRADE SECRET for the full calculation of each scenario. Please note, no scenarios represent the Company's full rate base and thus do not represent a total revenue requirement. The costs included for the current generation are the variable costs only, which are then added to the full cost of any additional generation needed as the system grows.

b. The Real Levelized Averages represent the average cents per kWh if the load were to grow at the rate of inflation.

c. The Real Levelized rates vary from year to year because they only measure the current year and remaining years levelized at the rate of inflation (e.g., 2026 calculates levelized 2026 through 2044, 2027 calculates levelized 2027 through 2044).

d. The Levelized Revenue Requirements represent the average cents per kWh if the load were to grow at the kWh growth projected for each scenario.

e. The Levelized Revenue Requirements vary from year to year because they only measure the current year and remaining years (e.g., 2026 calculates levelized 2026 through 2044, 2027 calculates levelized 2027 through 2044).

f. Please see STF-LA-1-1 Attachment TRADE SECRET column L of each scenario for the revenue requirements without levelization.

g. Please see STF-LA-1-1 Attachment TRADE SECRET cell P12 in each scenario page for the after-tax discount rate used to calculate Net Present Values in columns L,M,P and R on row 40. All values and calculations are provided in the attachment.

h. Please see STF-LA-1-1 Attachment TRADE SECRET. Row 40 shows the NPV for each scenario.

i. Please see STF-LA-1-1 Attachment TRADE SECRET column L. Rows 20-38 show the nominal revenue requirements.

j. No, none of the scenarios represent the Company's base rate case revenue requirements. The Company has not yet prepared its 2025 base rate case budget, which is required to be

Georgia Power Company
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2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

filed by July 1, 2025. Information about the future base rate case will be available once the rate case has been prepared and filed. Please note, no scenarios represent the Company's full rate base and thus do not represent a total revenue requirement. The costs included for the current generation are the variable costs only which are then added to the full cost of any additional generation needed as the system grows.

k. The Company has not yet prepared its 2025 base rate case budget. Information about the future base rate case will be available once the rate case has been prepared and filed.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY
DOCKET NO. 55378**

Data Request No. STF-DEA-3-6

**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-3-6 ("Response"). In the Response, the Company has provided forward-looking estimates of revenues, loads, and costs for specific capacity projects. 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 detailed data related to the Company's load and revenue forecast in addition to the estimated costs for capacity, financing, capital costs, unit, and operation 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.

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-DEA Data Request Set Number 3

STF-DEA-3-6

Question:

Provide a forecast of upcoming price increases as a result of the inclusion of Plant Vogtle Units 3 and 4 into rate base as well as the new load acquisitions necessary to serve major new load growth.

Response:

Per Commission approval of the Stipulation in Georgia Power's Application to Adjust Rates to Include Reasonable and Prudent Plant Vogtle Units 3 and 4 Costs in Docket No. 29849, the base rate change will result in an increase of approximately 5% for the average retail customer, which translates to \$8.95 per month for a typical residential customer using an average of 1,000 kWh/month. This base rate change will occur the month following the commercial operation date ("COD") of Plant Vogtle Unit 4. Based on the current schedule, rates would change April 1, 2024.

All else being equal, the Company expects that the projected revenues associated with incremental load from known new customer projects, which necessitate the additional capacity requested in the 2023 IRP Update, will fully offset the costs of those resources requested in the 2023 IRP Update and put downward pressure on overall retail rates. Please note, the projected revenues provided are preliminary estimates at this point in time and may differ from future revenues. See TS STF-DEA-3-6 Attachments A-I for additional information.

January 12, 2024 Supplemental Filing Update: 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 cost and construction schedule for the proposed Plant Yates combustion turbines ("CTs"). Details are provided in TS STF-DEA-3-6 Supplemental Attachment G and are incorporated in row 16 for Plant Yates Units 8-10 on the "Estimated Inc Rev Req" worksheet in TS STF-DEA-3-6 Supplemental Attachment A.

February 9, 2024 Supplemental Filing Update: The Company is providing all values on the "Estimated Net Impact" worksheet for public disclosure in PD STF-DEA-3-6 Supplemental 2-9-24 Attachment A.

2023 IRP Update - Estimated Net Impacts to Customers

These are preliminary estimates isolated to only the 2023 IRP Update proposed resources and external adjustments for won and potential large load projects. Values stated in millions of dollars and rounded to nearest ten million. Estimates are subject to change. Fuel costs and revenues not included in estimated incremental revenue requirements and estimated incremental revenue. *Reflects projected transmission capital associated with Plant Yates Units 9-10. Does not include revenue requirements for transmission projects that may be identified and placed in service in 2026-2028 due to load growth. ** Estimated revenues based on 2023 IRP Update external adjustments for won and potential large load projects.

Cumulative View

	2026	2027	2028
Estimated Incremental Revenue Requirement due to Load Growth*	\$190	\$580	\$620
Estimated Incremental Revenue due to Load Growth**	\$340	\$680	\$860
Net Estimated Cumulative Impact to Customers	-\$150	-\$100	-\$240

Incremental View

	2026	2027	2028
Total Revenues	\$10,970	\$10,660	\$10,760
Estimated Incremental Revenue Requirement due to Load Growth*	\$190	\$390	\$40
Estimated Incremental Revenue due to Load Growth**	\$340	\$340	\$190
Net Estimated Incremental Impact to Customers	-\$150	\$50	-\$150
Estimated Rate Impact (%)	-1.4%	0.5%	-1.4%
Cumulative (compounded) %	-1.4%	-0.9%	-2.3%
Estimated Typical Residential \$/month impact	-\$2.58	\$0.86	-\$2.58
Cumulative Typical Residential \$/month Impact	-\$2.58	-\$1.72	-\$4.30

2023 IRP Update - Estimated Incremental Revenue Requirements

These are preliminary estimates isolated to only the 2023 IRP Update proposed resources and external adjustments for won and potential large load projects. Values stated in millions of dollars. Estimates are subject to change. Fuel costs not included in estimated incremental revenue requirements.

*Reflects projected transmission capital associated with Plant Yates Units 8-10. Does not include revenue requirements for transmission projects that may be identified and placed in service in 2026-2028 due to load growth

Proposed Resource	2026	2027	2028	Source
Mississippi Power PPA	REDACTED	REDACTED	REDACTED	In line - reflects PPA capacity pricing plus requested additional sum
Santa Rosa PPA	REDACTED	REDACTED	REDACTED	TS STF-DEA-3-6 Attachment B - "Santa Rosa" tab - row 39
Moody BESS	REDACTED	REDACTED	REDACTED	TS STF-DEA-3-6 Attachment C - "Financial Engine" tab - row 18
Robins BESS	REDACTED	REDACTED	REDACTED	TS STF-DEA-3-6 Attachment D - "Financial Engine" tab - row 18
Co-located BESS	REDACTED	REDACTED	REDACTED	TS STF-DEA-3-6 Attachment E - "Financial Engine" tab - row 18
Co-located Solar	REDACTED	REDACTED	REDACTED	TS STF-DEA-3-6 Attachment F - "Financial Engine" tab - row 18
Other BESS	REDACTED	REDACTED	REDACTED	In line - assumed to be in proportion to Robins BESS
Plant Yates Units 8-10	REDACTED	REDACTED	REDACTED	TS STF-DEA-3-6 Supplemental Attachment G - "Financial Engine" tab - row 18
Transmission Capex*	REDACTED	REDACTED	REDACTED	TS STF-DEA-3-6 Attachment H - "Transmission" tab - row 32
Amortization of Reg Asset	REDACTED	REDACTED	REDACTED	"Deferral Calculation" tab
Total Estimated Incremental Revenue Requirement	\$190	\$581	\$618	Sum

2023 IRP Update - Estimated Incremental Revenue Requirements for Net Deferred Costs of PPAs

Values stated in millions of dollars. Estimates are subject to change. Fuel costs not included in estimated incremental revenue requirements. Estimates do not include revenues from any future remarketing of remaining PPA capacity which will further offset the net deferred costs.

	2024	2025	2026	2027	2028
Mississippi Power PPA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Regional Sale PPA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Santa Rosa PPA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total Amount Deferred	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Reg Asset Beginning Balance	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Amortization	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Reg Asset Ending Balance	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Deferred Tax Liability	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Average	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Pre-Tax Weighted Average Cost of Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Financing Cost on Reg Asset	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

2023 IRP Update - Estimated Incremental Revenue

These are preliminary estimates isolated to only the 2023 IRP Update proposed resources and external adjustments for won and potential large load pro. Values stated in millions of dollars. Estimates are subject to change. Fuel revenues not included in estimated incremental revenue.

**Estimated revenues based on 2023 IRP Update external adjustments for won and potential large load projects.*

	2026	2027	2028	Source
Estimated Incremental Revenue due to Load Growth ¹	\$339	\$679	\$864	TS STF-DEA-3-6 Attachment I - "Summary" tab - cells N6:N8

Total Revenues

Values stated in millions of dollars. Estimates are subject to change.

	2026	2027	2028
Budget 2023 Total non-fuel Revenues	\$8,077	\$8,124	\$8,195
Fuel (FCR26 settlement budget)	\$2,889	\$2,540	\$2,562
Total Revenues	\$10,966	\$10,664	\$10,757
Net Incremental Revenue Requirement	-\$150	\$50	-\$150
Grossed up for MIFB impact	-\$154	\$51	-\$154

EXHIBIT__(RS/JF-3)

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 2

STF-LA-2-20

Question:

How are the Additional Sum amounts for Renewable Energy PPAs treated in the Company's base rate case and Annual Surveillance Reports (ASRs)?

Response:

For both the base rate case revenue requirement and the ASRs, additional sum amounts for Renewable Energy PPAs are treated as a regulatory expense and are not recorded in the Company's general ledger, but are included in the Company's retail cost of service through a column adjustment.

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 3

STF-LA-3-4

Question:

How does the Company propose to treat the Additional Sum amounts for the new Capacity and Energy PPAs in the Company's base rate case and Annual Surveillance Reports (ASRs)?

Response:

Similar to the current regulatory treatment of approved PPA additional sums, for both the base rate case revenue requirement and the ASRs, additional sum amounts for the new Capacity and Energy PPAs will be treated as a regulatory expense that is not recorded in the Company's general ledger but is included in the Company's retail cost of service through a column adjustment.

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 3

STF-LA-3-5

Question:

How are the Additional Sum amounts for Capacity and Energy PPAs considered in the Company's economic valuation of Capacity and Energy purchases?

Response:

Additional sum was not a factor in the economic valuation of Capacity and Energy purchases. Any additional sum is applied to each PPA after it is selected and therefore does not change the relative position of the PPA in an RFP selection process.

EXHIBIT__(RS/JF-4)

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY
DOCKET NOS. 56002 & 56003**

Data Request No. STF-LA-1-8

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

As part of Georgia Power Company's 2025 Integrated Resource Plan filed in Docket No. 56002 ("2025 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 56003 ("2025 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-8 ("Response"). In the Response, the Company has provided forecast amounts for anticipated federal tax credits. All of such information (the "Information") 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 resource planning process and pricing assumptions. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers.

The 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.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-8

Question:

Refer to the tables on pages 2 through 14 of 14.

- a. Are any production tax credits or investment tax credits anticipated for any of the years shown? If yes, identify the amounts of PTCs and ITCs that are anticipated for each year under each scenario.
- b. Have any PTCs or ITCs been reflected in any of the amounts on pages 2 through 14? If not, explain fully why not. If so, show the amounts of PTC and ITCs for each year that have been reflected in the financial analysis.
- c. Are any other federal income tax benefits, beyond PTCs and ITCs anticipated for any of the years shown? If yes, identify the amounts of each such federal tax benefit that is anticipated for each year under each scenario.
- d. Are any state income tax benefits anticipated for any of the years shown? If yes, identify the amounts of each such state tax benefit that is anticipated for each year under each scenario.

Response:

- a. Yes, the total annual revenue requirements include production tax credits (“PTCs”) and investment tax credits (“ITCs”) for the generic expansion resources selected in each of the sensitivities included in the Financial Review. The Company did not separately calculate the amounts of PTCs and ITCs for each of these sensitivities. Rather, the Company included the anticipated amounts of the PTCs and ITCs for generic technologies in the capital cost calculation included in the expansion plan analyses used in the Financial Review. The Company provided detailed PTC, ITC, and technology cost assumptions in Table 2 of Technical Appendix 2 Resource Mix Study TRADE SECRET. The Aurora output files that include the capacity expansions for each sensitivity were provided to Commission Staff on January 31, 2025, in the workpapers for Technical Appendix 2 Resource Mix Study. STF-LA-1-8 Attachment TRADE SECRET provides the NPV of tax credits by commercial operation date (“COD”) year for each technology in the Mix Study that is eligible for tax credits (ITC, PTC and 45Q). This information can be used to calculate the approximate total amounts of tax credits for each sensitivity.
- b. See response to subpart (a).

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

c. No.

d. No.

NPV of IRA Tax Credits for Generic Resources for Each COD Year

PTC NPV (\$/kw)		2028	2029	2030	2031	2032	2033	2034	2035
Technology	COD Year	2028	2029	2030	2031	2032	2033	2034	2035
Solar	PTC NPV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Wind	PTC NPV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

ITC NPV (\$/kw)		2028	2029	2030	2031	2032	2033	2034	2035
Technology	COD Year	2028	2029	2030	2031	2032	2033	2034	2035
BESS	Capital ITC NPV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	MC ITC NPV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
MDESS	Capital ITC NPV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	MC ITC NPV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Nuclear (AP1000)	Capital ITC NPV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	MC ITC NPV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

45Q NPV (\$/kw)		2028	2029	2030	2031	2032	2033	2034	2035
Technology	COD Year	2028	2029	2030	2031	2032	2033	2034	2035
CC w CCS		REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

*45Q based on assumed capacity factor used in O&M calculations, actual, per unit 45Q value from expansion units will vary with energy budget run profiles. CF assumptions are 85% for CCwCCS
 *ITC Credits available for storage technology Maintenance Capital ("MC"), calculated using K-factor from pre-cod ITC and escalated
 *ITC/PTC Monetized at 90%, use 75% for 45Q eligible technologies

The table below shows the IRA tax credit phase out assumptions for each scenario. The table shows the last year of credit availability for each resource

Technology	Tech Portfolio	IRA 2045	IRA 2035
Wind/Solar/Storage	Through model horizon	2048	2038
	Nuclear	2052	2042
CCS	2038	2038	2038

PUBLIC DISCLOSURE

2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

PUBLIC DISCLOSURE

2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

2058	2059
REDACTED	REDACTED
REDACTED	REDACTED

2058	2059
REDACTED	REDACTED
REDACTED	REDACTED
REDACTED	REDACTED
REDACTED	REDACTED
REDACTED	REDACTED

2058	2059
REDACTED	REDACTED

EXHIBIT__(RS/JF-5)

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1**

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

As part of Georgia Power Company's 2025 Integrated Resource Plan filed in Docket No. 56002 ("2025 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 56003 ("2025 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-9 ("Response"). In the Response, the Company has provided detailed projections of capital expenditures by individual environmental controls and operation and maintenance costs for specific environmental items. 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 sensitive cost data that suppliers of environmental control equipment and vendors of operation and maintenance materials, such as limestone and ammonia, could use to tailor proposals according to the Company's expected costs to the detriment of customers. Georgia Power's ability to negotiate the optimum price and contract terms and conditions would be undermined if competitors and suppliers had access to the projections contained in the Information, which could result in higher costs to the Company and its 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.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-9

Question:

Please reference the Environmental Compliance Cost Recovery (ECCR) Summary of Capital Expenditures, Closures, and O&M Expenses. In the same format as the Company's response to STF-11-1 in Docket No. 36498:

- a. Please provide a breakdown of each numerical value in the table by generating unit.
- b. Please provide all supporting documents/workpapers that were used to compute the values in the table. Workpapers should be supplied electronically with all formulas attached and no pasted in data assumptions should exist.

Response:

Please see STF-LA-1-9 Attachment TRADE SECRET.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**Georgia Power Company
Docket No. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1**

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

As part of Georgia Power Company's 2025 Integrated Resource Plan filed in Docket No. 56002 ("2025 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 56003 ("2025 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-12 ("Response"). In the Response, the Company has provided detailed projections of capital expenditures by individual environmental controls and operation and maintenance costs for specific environmental items. 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 data that suppliers of environmental control equipment and vendors of operation and maintenance materials, such as limestone and ammonia, could use to tailor proposals according to the Company's expected costs to the detriment of customers. Georgia Power's ability to negotiate the optimum price and contract terms and conditions would be undermined if competitors and suppliers had access to the projections contained in the 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.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-12

Question:

Please provide the Company's ECCR projection of estimated Capital Expenditures, Closures, and O&M Expenses beyond the year 2028. If such a projection is not available, please explain.

Response:

The Company's currently estimated amount of Capital Expenditures, Plant Closures, and O&M expenses related to ECCR for year 2029 is included in STF-LA-1-12 Attachment TRADE SECRET. The Company does not maintain a Capital/Closures and O&M ECCR budget beyond 5 years.

PUBLIC DISCLOSURE

Environmental Compliance Cost Recovery (ECCR)
Summary of Capital Expenditures, Closures, and O&M Expenses
(millions of dollars)

	<u>2029</u>
Total Capital Expenditures	REDACTED
Total Closures to Plant	REDACTED
Total O&M Expenses	REDACTED

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY
DOCKET NOS. 56002 & 56003**

Data Request No. STF-LA-1-14

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

As part of Georgia Power Company's 2025 Integrated Resource Plan filed in Docket No. 56002 ("2025 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 56003 ("2025 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-14 ("Response"). In the Response, the Company has provided detailed projections of capital expenditures by individual environmental controls and operation and maintenance costs for specific environmental items. 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 data that suppliers of environmental control equipment and vendors of operation and maintenance materials could use to tailor proposals according to the Company's expected costs to the detriment of customers. Georgia Power's ability to negotiate the optimum price and contract terms and conditions would be undermined if competitors and suppliers had access to the projections contained in the Information. Lastly, the Company's competitors are not required to disclose this 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.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-14

Question:

Refer to the Technical Appendix Volume 2. Referring to the Environmental Compliance Cost Recovery (ECCR) Table, identify the accounts in which each of the amounts listed on that table were recorded through 2024 and would be recorded for years 2025 through 2028.

Response:

Please see the Company's response to STF-LA-1-9 for detailed support for the ECCR Table.

Capital expenditures are recorded to FERC account 107 (Construction Work in Progress) prior to being placed in service, and once they are closed to plant in service, as represented by closures to plant, they are recorded to FERC account 101 (Plant in Service).

Please see STF-LA-1-14 Attachment TRADE SECRET for O&M by FERC account.

PUBLIC DISCLOSURE

Georgia Power Company
Projected ECCR O&M Expenses by FERC Account
Amounts in Millions

FERC Account	2025	2026	2027	2028
500	REDACTED	REDACTED	REDACTED	REDACTED
502	REDACTED	REDACTED	REDACTED	REDACTED
505	REDACTED	REDACTED	REDACTED	REDACTED
506	REDACTED	REDACTED	REDACTED	REDACTED
510	REDACTED	REDACTED	REDACTED	REDACTED
511	REDACTED	REDACTED	REDACTED	REDACTED
512	REDACTED	REDACTED	REDACTED	REDACTED
539	REDACTED	REDACTED	REDACTED	REDACTED
549	REDACTED	REDACTED	REDACTED	REDACTED
551	REDACTED	REDACTED	REDACTED	REDACTED
553	REDACTED	REDACTED	REDACTED	REDACTED
557	REDACTED	REDACTED	REDACTED	REDACTED
568	REDACTED	REDACTED	REDACTED	REDACTED
588	REDACTED	REDACTED	REDACTED	REDACTED
595	REDACTED	REDACTED	REDACTED	REDACTED
920	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**Georgia Power Company
Docket No. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1**

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

As part of Georgia Power Company's 2025 Integrated Resource Plan filed in Docket No. 56002 ("2025 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 56003 ("2025 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-15 ("Response"). In the Response, the Company has provided detailed projections of capital expenditures by individual environmental controls and operation and maintenance costs for specific environmental items. 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 data that suppliers of environmental control equipment and vendors of operation and maintenance materials, such as limestone and ammonia, could use to tailor proposals according to the Company's expected costs to the detriment of customers. Georgia Power's ability to negotiate the optimum price and contract terms and conditions would be undermined if competitors and suppliers had access to the projections contained in the 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.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-15

Question:

Refer to the Technical Appendix Volume 2. Referring to the Environmental Compliance Cost Recovery (ECCR) Table, identify the amounts of projected Capital Expenditures for each plant, for each year, 2025 through 2028, for each of the following items:

- a. Scrubbers
- b. SCRs 6
- c. Waste Water Treatment
- d. MATS
- e. CCR ash management
- f. CCR landfill construction
- g. All other controls

Response:

Please see STF-LA-1-15 Attachment TRADE SECRET.

PUBLIC DISCLOSURE

Capital Expenditures by Unit
(\$ in millions)

	<u>2025</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>
<u>Scrubbers</u>				
Bowen 1	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 3	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 4	REDACTED	REDACTED	REDACTED	REDACTED
Bowen Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED
<u>SCRs</u>				
Bowen 1	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 3	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 4	REDACTED	REDACTED	REDACTED	REDACTED
Bowen Common	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 4	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 5	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 10	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 11	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED
<u>Waste Water Treatment</u>				
Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 3	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 4	REDACTED	REDACTED	REDACTED	REDACTED
Bowen Common	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 4	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Yates 6&7 Common	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED
<u>All Other Controls</u>				
Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 3	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 4	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 4	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 5	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 6	REDACTED	REDACTED	REDACTED	REDACTED
McDonough CC Common	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 1	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 2	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 4	REDACTED	REDACTED	REDACTED	REDACTED

PUBLIC DISCLOSURE

	<u>2025</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>
McIntosh 5&6	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 7	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 8	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh CT	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh CC Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Yates 7	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED

Mercury and Air Toxics Standards (MATS)

Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 3	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 4	REDACTED	REDACTED	REDACTED	REDACTED
Bowen Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED

Coal Combustion Residual (CCR)

Ash Management

Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1-2	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED

Landfill

Bowen Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED

Total Capital Expenditures \$ 153.2 \$ 358.8 \$ 202.2 \$ 243.9

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**Georgia Power Company
Docket No. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1**

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

As part of Georgia Power Company's 2025 Integrated Resource Plan filed in Docket No. 56002 ("2025 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 56003 ("2025 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-16 ("Response"). In the Response, the Company has provided detailed projections of capital expenditures by individual environmental controls and operation and maintenance costs for specific environmental items. 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 data that suppliers of environmental control equipment and vendors of operation and maintenance materials, such as limestone and ammonia, could use to tailor proposals according to the Company's expected costs to the detriment of customers. Georgia Power's ability to negotiate the optimum price and contract terms and conditions would be undermined if competitors and suppliers had access to the projections contained in the 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.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-16

Question:

Refer to the Technical Appendix Volume 2. Referring to the Environmental Compliance Cost Recovery (ECCR) Table, identify the amounts of projected Closures to Plant for each plant, for each year, 2025 through 2028, for each of the following items:

- a. Scrubbers
- b. Waste Water Treatment
- c. MATS Docket
- d. CCR ash management
- e. CCR landfill construction
- f. All other controls

Response:

Please see STF-LA-1-16 Attachment TRADE SECRET.

PUBLIC DISCLOSURE

**Closures to Plant by Unit
(\$ in millions)**

	<u>2025</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>
<u>Scrubbers</u>				
Bowen 1	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 3	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 4	REDACTED	REDACTED	REDACTED	REDACTED
Bowen Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED
<u>SCRs</u>				
Bowen 1	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 3	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 4	REDACTED	REDACTED	REDACTED	REDACTED
Bowen Common	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 4	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 5	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 6	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 10	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 11	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED
<u>Waste Water Treatment</u>				
Bowen 1	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 3	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 4	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 4	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Yates 6&7 Common	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED
<u>All Other Controls</u>				
Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 3&4	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 4	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 4	REDACTED	REDACTED	REDACTED	REDACTED
McDonough 5	REDACTED	REDACTED	REDACTED	REDACTED

PUBLIC DISCLOSURE

	<u>2025</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>
McDonough 6	REDACTED	REDACTED	REDACTED	REDACTED
McDonough CC Common	REDACTED	REDACTED	REDACTED	REDACTED
McDonough Common	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 1	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 2	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 4	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 5&6	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 7	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 8	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh CT	REDACTED	REDACTED	REDACTED	REDACTED
Mcintosh Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1-2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1-3	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Wilson CT	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED
<u>Mercury and Air Toxics Standards (MATS)</u>				
Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 3	REDACTED	REDACTED	REDACTED	REDACTED
Bowen 4	REDACTED	REDACTED	REDACTED	REDACTED
Bowen Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED
<u>Coal Combustion Residual (CCR)</u>				
<u>Ash Management</u>				
Bowen 2	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 1	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED
<u>Landfill</u>				
Bowen Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer Common	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED
Total Closures to Plant	REDACTED	REDACTED	REDACTED	REDACTED

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-18

Question:

Refer to the Technical Appendix Volume 2. Referring to the Environmental Compliance Cost Recovery (ECCR) Table, did the Company (including SCS or any other organization on behalf of the Company) prepare more than one estimate for the environmental projects detailed in that Table?

- a. If not, explain fully why not.
- b. If so, provide the estimates.
- c. How did the Company decide which estimate was most appropriate?

Response:

The Company did not create separate estimates but rather considered compliance options as they were evaluated. The resulting estimates are included in the Environmental Compliance Strategy (“ECS”) and incorporated into the unit retirement study scenarios. Following this analysis, the Company determines the most cost-effective approach for each unit that meets regulatory requirements. The most appropriate approach for each unit may not be the least cost option, all things held equal, because of the unit-specific risks and requirements to comply and the need to incorporate reliability considerations. Where appropriate, the Company continues to look for alternative compliance options that are in the best interest of customers.

The development of the Company’s ECS first considers a regulatory review of current and possible future local, state, regional, and federal environmental requirements. Following the regulatory review, the Company evaluates the specific requirements for each generating plant and/or unit, as well as availability and the timeline to implement the control technology, to determine what control technology options are available to comply. The feasible control options are evaluated based on technical performance, reliability, operational flexibility, and capital and O&M cost impacts. These evaluations can be developed over several years as the dynamic environmental regulatory landscape changes (as shown by the Company’s ongoing strategy for ELG compliance), and the Company undergoes an iterative process, both with industry vendors and internally, to prepare the estimates provided in the ECCR table.

Please see the Company’s response to STF-LA-1-11 and STF-JKA-1-21 for estimates and information used in the development of the ECCR table. Projects that are routine to the plant are estimated based on prior experience and material quotes and contain labor and material escalations.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-19

Question:

Concerning the Company's ECCR costs and recovery, please respond to the following:

- a. Identify the Company's under- or over-recovered ECCR balance as of each of the following dates: (1) 12/31/2023 and (2) 12/31/2024.
- b. Show in detail how ECCR costs were being recovered and the recovery amounts per month through 12/31/2024 that resulted in the under-recovery or over-recovered balance through 12/31/2024.

Response:

The ECCR tariff, as approved by the Commission in the 2022 Rate Case in Docket No. 44280, is not subject to a true-up and therefore, the Company does not maintain an under- or over-recovery balance related to ECCR tariff.

**Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1**

STF-LA-1-20

Question:

How much contingency is included in each of the ECCR Capital Expenditure amounts from Technical Appendix, Volume 2, ECCR, page 1 of 1, for each year 2025 through 2028:

Provide details showing how the contingency amounts in each component of ECCR Capital Expenditure costs were determined.

Response:

The total ECCR capital expenditures for the years 2025-2028 is \$958.10M, which includes collective contingency of approximately \$141M for environmental compliance strategy capital projects. Details regarding project contingency can be found in the Company's responses to STF-JKA-1-21 and STF-LA-1-11.

Incorporating project contingency is a common industry practice that is necessary and appropriate to account for inherent project-specific risk exposure associated with complex projects. As a project moves into construction, and more certainty is gained, the level of contingency needed to account for risk exposure may be reduced. Projects that are routine to the plant are estimated based on prior experience, material quotes, and contain labor and material escalations where appropriate.

EXHIBIT__(RS/JF-6)

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**Georgia Power Company
Docket No. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1**

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

As part of Georgia Power Company's 2025 Integrated Resource Plan filed in Docket No. 56002 ("2025 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 56003 ("2025 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-26 ("Response"). In the Response, the Company has provided detailed financial information regarding the estimated future expenditures for ash pond closures. 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 the Company is expected to incur to close its ash ponds. Publicly disclosing these costs would allow vendors to tailor proposals according to the Company's expected costs to the detriment of the Company and its customers. Disclosure of the Information could harm the Company in its efforts to obtain optimal pricing in current or future negotiations for these ash pond closure services.

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.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-26

Question:

For the Coal Combustion Residuals Asset Retirement Obligations:

- a. Please provide a breakdown of each CCR ARO by generating unit.
- b. Please provide all supporting documents/workpapers that were used to compute those values. Workpapers should be supplied electronically with all formulas attached and no pasted in data assumptions should exist.
- c. Identify the accounts in which each of the amounts were recorded by year for 2022 through 2024 and that are expected to be recorded for years 2025 and beyond.
- d. Please describe how the estimates identified in the response to the above parts of this request were determined and provide all supporting documents, workpapers and reports that were used in preparing the cost estimates.

Response:

- a. Please see the Company's 2025 IRP Filing, Technical Appendix Volume 1, Selected Supporting Information, CCR ARO Table for a breakdown of CCR ARO by plant site. CCR ash pond and landfill AROs are accounted for as a common plant asset and therefore are not available by generating unit.
- b. Please see STF-LA-1-26 Attachment TRADE SECRET.
- c. For the years 2022 through 2024, the CCR asset retirement obligations amounts were recorded to FERC 230 Asset Retirement Obligation Liability and FERC 101 Plant in Service. The same accounts are expected to be used for years 2025 and beyond.
- d. The estimates included in this response can be found in the 2025 Environmental Compliance Strategy ("ECS") describing how the Company determined the requirements and strategy related to the CCR ARO projects found in Technical Appendix Volume 1. Specifically, within the ECS, Section 2 provides a detailed overview of the applicable environmental laws and regulations for the Company's CCR ARO projects and outlines the Company's comprehensive strategy for compliance.

Please also refer to the Company's response to STF-LA-1-24 for supporting documents used in preparing the estimates.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-27

Question:

Identify and provide the journal entries in 2024 used to record the CCR ARO for each ash pond and landfill. Include the related supporting workpapers.

Response:

The computation of the ARO liability occurs in the PowerPlan ARO Asset module based on the data inputs provided in STF-LA-1-26 Attachment TRADE SECRET.

The journal entries to record the 2024 CCR ARO updates are as follows:

DR 101 Plant in Service	\$58,987,892	
CR 230 ARO Liability		(\$58,987,892)

(To record initial or revised fair value of the ARO Liability)

DR 108 ARO Retirements	\$92,178,794	
CR 101 Plant in Service		(\$92,178,794)

DR 411.7 Loss on ARO Settlements	\$204,170,582	
CR 411.6 Gain on ARO Settlements		(\$111,991,788)
CR 108 ARO Retirements		(\$92,178,794)

DR 182 Regulatory Asset	\$92,178,794	
DR 411.6 Gain on ARO Settlements	\$111,991,788	
CR 411.7 Loss on ARO Settlements		(\$204,170,582)

(To retire and reclassify ARC Asset (FERC 101) to regulatory asset for previously retired/converted generating plants due to end of life)

The journal entries to record the CCR ARO settlements that occurred in 2024 are as follows:

DR 108 Cost of Removal	\$264,755,376	
CR 131 Cash		(\$264,755,376)

DR 230 ARO Liability	\$264,755,376	
CR 108 Cost of Removal		(\$264,755,376)

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

DR 254 Regulatory Liability	\$264,755,376	
CR 182 Regulatory Asset		(\$264,755,376)

(To record settlements of the ARO Liability)

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**Georgia Power Company
Docket No. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1**

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

As part of Georgia Power Company's 2025 Integrated Resource Plan filed in Docket No. 56002 ("2025 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 56003 ("2025 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-28 ("Response"). In the Response, the Company has provided external consulting and internal labor cost estimates. 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 the Company is expected to incur to close its ash ponds. 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.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-28

Question:

Identify and provide the correspondence to and from the Company and its external auditors concerning the recording of the CCR AROs in 2024.

Response:

A list of the correspondence to and from the Company and its external auditor, Deloitte, concerning the recording of the CCR ARO in 2024 is identified in the table below. All attachments are redacted in their entirety for public disclosure purposes.

File Name	Correspondence Regarding
STF-LA-1-28 Attachment A	Q4 2024 ARO Current Liability Reclass
STF-LA-1-28 Attachment B	ARO Regulation and Groundwater Monitoring Search
STF-LA-1-28 Attachment C	Q4 ARO Update Workbook
STF-LA-1-28 Attachment D	Year End ARO Roll forward
STF-LA-1-28 Attachment E	Year End ARO Roll forward Follow Up
STF-LA-1-28 Attachment F	ARO Report Year to Date at December 2024
STF-LA-1-28 Attachment G	Q4 2024 ARO Quarterly Meeting Checklist
STF-LA-1-28 Attachment H	ARO Settlement Query for Selections
STF-LA-1-28 Attachment I	ARO Settlement Selection by Deloitte
STF-LA-1-28 Attachment J	ARO Settlement Selection Line Item and Support
STF-LA-1-28 Attachment K	ARO Settlement Selection Invoice Questions

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**Georgia Power Company
Docket No. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1**

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

As part of Georgia Power Company's 2025 Integrated Resource Plan filed in Docket No. 56002 ("2025 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 56003 ("2025 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-29 ("Response"). In the Response, the Company has provided detailed financial information regarding the estimated future expenditures for ash pond closures (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 contains competitively sensitive details on the costs the Company is expected to incur to close its ash ponds. Publicly disclosing these costs would allow vendors to tailor proposals and negotiate pricing according to the Company's expected costs and could set an artificial floor on the pricing for these services. Therefore, disclosure of the Information would undermine the Company's ability to negotiate for and procure best cost resources from prospective vendors. In turn, the disclosure of the Information could prevent the Company from obtaining optimal pricing in current or future negotiations, to the detriment of the Company and its 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.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-29

Question:

Identify and explain how the Company is accounting for CCR costs at plants that have been retired through 12/31/2024. Identify the amount of remaining CCR ARO as of 12/31/2024 and as estimated for 12/31/2025, 12/31/2026, 12/31/2027 and 12/31/2028 at each retired steam generating plant.

Response:

The Company accounts for coal combustion residuals (“CCR”) costs at all plant sites based on the Financial Accounting Standards Board’s Accounting Standards Codification (“ASC”) Topic 410, *Asset Retirement and Environmental Obligations* since its adoption in 2003. As such, the CCR asset retirement obligation (“ARO”) accounting entries for each plant site follow the accounting entries listed below which are in accordance with ASC 410-20 and ASC 980.

FAS 143/ASC 410 GAAP Accounting	<p>Recognize new ARO or Update existing ARO DR 101 Plant in Service CR 230 Asset Retirement Obligation Liability <i>(To record initial fair value of the ARO Liability)</i></p> <p>Retire ARC Asset DR 108 Accumulated Reserve CR 101 Plant in Service <i>(To retire ARC Asset at retired or converted plant site; no longer coal generating)</i></p> <p>Clear Accumulated Reserve for Retirement DR 411 Loss on ARO CR 108 Accumulated Reserve <i>(See step below to clear loss from income statement)</i></p> <p>Accretion of ARO Liability [FAS 143/ASC 410 (Over life)] DR 411 Accretion Expense CR 230 Asset Retirement Obligation Liability <i>(To record accretion expense on the ARO liability)</i></p>
Accounting Provided by our Regulator (ASC 980)	<p>Rate Recovery DR 407 Regulatory Debit CR 254 Regulatory Liability <i>(To record a regulatory liability related to ARO costs recovered from customers in rates)</i></p>

Georgia Power Company
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Reversing the effects of FAS 143/ASC 410 GAAP Accounting

Defer Accretion
 DR 182 Regulatory Asset
 CR 407 Regulatory Credit
 Defer Loss on Retirement
 DR 182 Regulatory Asset
 Cr 411 Loss on ARO

(To defer accretion expense and loss on retirement to regulatory asset. GAAP and Ratemaking accounting entries must both be followed; however, the Company cannot book both. Therefore, the effects of FAS 143/ASC 410 are reversed and only the actions of the regulator are reflected in the Company's financial statements)

FAS 143/ASC 410 GAAP Accounting

Settlements
 DR 108 Cost of Removal
 CR Cash
 DR 230 Asset Retirement Obligation
 CR 108 Cost of Removal
 DR 254 Regulatory Liability
 CR 182 Regulatory Asset

(To record settlement of the ARO liability)

Please see STF-LA-1-29 Attachment TRADE SECRET for the CCR ARO balances recorded in FERC 230- Asset Retirement Obligation, by steam generating plant, as of 12/31/2024 and as estimated for 12/31/2025, 12/31/2026, 12/31/2027 and 12/31/2028.

PUBLIC DISCLOSURE

Georgia Power Company
Estimated Remaining CCR ARO Cost
 (\$ in millions)

<u>Facility</u>	<u>Coal Generating Status</u>	<u>12/31/2024</u>	<u>12/31/2025</u>	<u>12/31/2026</u>	<u>12/31/2027</u>	<u>12/31/2028</u>
Arkwright	Retired	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bowen	Operating	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Branch	Retired	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Hammond	Retired	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Kraft	Retired	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McDonough	Converted	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh	Retired	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McManus	Retired	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Mitchell	Retired	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer	Operating	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Wansley	Retired	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Yates	Retired/Converted	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total		\$ 6,252.4	\$ 5,956.7	\$ 5,622.4	\$ 5,321.3	\$ 5,032.2

Note: CCR ARO Accounting for retired and/or converted plants is the same.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-30

Question:

Identify and explain how the Company is accounting for CCR costs at plants that are expected to continue to operate after their ash ponds are closed and remediated. Identify the amount of CCR ARO as of 12/31/2024 and as estimated for 12/31/2025, 12/31/2026, 12/31/2027 and 12/31/2028 at each such steam generating plant.

Response:

The Company accounts for coal combustion residuals (“CCR”) costs at all plant sites based on the Financial Accounting Standards Board’s Accounting Standards Codification (“ASC”) Topic 410, *Asset Retirement and Environmental Obligations* since its adoption in 2003. As such, the CCR asset retirement obligation (“ARO”) accounting entries for each plant site follow the accounting entries listed below which are in accordance with ASC 410-20 and ASC 980.

FAS 143/ASC 410 GAAP Accounting	<p>Recognize new ARO or Update existing ARO DR 101 Plant in Service CR 230 Asset Retirement Obligation Liability <i>(To record initial fair value of the ARO Liability)</i> Depreciation of ARC Asset [FAS 143/ASC 410 (Over life)] DR 403 Depreciation Expense CR 108 Accumulated Reserve <i>(To record straight-line depreciation on the asset retirement cost)</i> Accretion of ARO Liability [FAS 143/ASC 410 (Over life)] DR 411 Accretion Expense CR 230 Asset Retirement Obligation Liability <i>(To record accretion expense on the ARO liability)</i></p>
Accounting Provided by our Regulator (ASC 980)	<p>Rate Recovery DR 407 Regulatory Debit CR 254 Regulatory Liability <i>(To record a regulatory liability related to ARO costs recovered from customers in rates)</i></p>
Reversing the effects of FAS 143/ASC 410 GAAP Accounting	<p>Defer Depreciation and Accretion DR 182 Regulatory Asset CR 407 Regulatory Credit <i>(To defer depreciation and accretion expense to regulatory asset. GAAP and Ratemaking accounting entries must both be followed; however, the Company cannot book both. Therefore, the effects of FAS 143/ASC 410 are reversed and only the actions of the regulator are reflected in the Company’s financial statements)</i></p>

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
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FAS 143/ASC
410 GAAP
Accounting

Settlements

DR 108 Cost of Removal

CR Cash

DR 254 Regulatory Liability

CR 182 Regulatory Asset

(To record settlement of the ARO liability)

DR 230 Asset Retirement Obligation

CR 108 Cost of Removal

Please see STF-LA-1-29 Attachment TRADE SECRET in the Company’s response to STF-LA-1-29 for the CCR ARO balances recorded in FERC 230 - Asset Retirement Obligation, by steam generating plant, as of 12/31/2024 and as estimated for 12/31/2025, 12/31/2026, 12/31/2027 and 12/31/2028.

EXHIBIT__(RS/JF-7)

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY
DOCKET NOS. 56002 & 56003**

Data Request No. STF-LA-1-25

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

As part of Georgia Power Company's 2025 Integrated Resource Plan filed in Docket No. 56002 ("2025 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 56003 ("2025 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-25 ("Response"). In the Response, the Company has provided details of its research and development activities related to ash processing and beneficial use. 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 details on the Company's research and development activities related to processing of harvested ash from Company ash ponds and beneficial use. To allow competitors of the Company to have access to such Information without similarly expending resources would put the Company at an economic disadvantage. In addition, if the Information was revealed to the public, suppliers, vendors, and service providers participating in these activities could use the Information to tailor proposals according to the Company's expected costs to the detriment of customers. Georgia Power's ability to negotiate the optimum price and contract terms would be undermined if suppliers, vendors, and service providers had access to the projections contained in the Information. Furthermore, competitors of the Company are generally not required to publicly disclose 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.

PUBLIC DISCLOSURE
Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-25

Question:

Regarding the Company's efforts to develop a center for beneficial use of harvested CCR and to develop new technologies or processes associated with beneficiation and expand current and potential markets, please provide the following information:

- a. Identify costs incurred through 2024 related to the center in total and by account.
- b. Identify costs projected in each year 2025, 2026, 2027 and 2028 related to the center in total and by account.
- c. Identify revenue received in each year, 2023 and 2024 related to harvested CCR for beneficial use.
- d. Identify revenue anticipated to be received in each year, 2025 through 2028 related to harvested CCR for beneficial use.
- e. Have any other utilities participated in funding the collaborative project with supporting contributions toward construction and operations and/or through funding from the EPRI?
- f. What portion of the funding for construction and operation of the center has come from EPRI?

Response:

- a. In 2018, the Company invested \$2.5 million for the establishment of the Ash Beneficial Use Center ("ABUC") at Plant Bowen. These costs were recorded to Federal Energy Regulatory Commission ("FERC") account 506 in December 2018. In December 2024, the Company invested another \$2.0 million for upgrades and general maintenance to the ABUC, as well as supplemental funding for two pilot projects expected to commence in 2025.
- b. No additional Georgia Power funding for the ABUC is currently projected for the years 2025 and beyond.
- c. The Company has not recognized and does not anticipate any revenue from harvesting CCR for beneficial use associated with the ABUC. During years 2023 and 2024 the Company did recognize the following amounts from harvesting CCR for beneficial use. Harvesting for response to this question and STF-L&A-1-25 (d) is defined as CCR removed from ash ponds or CCR landfills for beneficial use.

EXHIBIT__(RS/JF-8)

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-38

Question:

Please specify the service lives that the Company assumes for ratemaking purposes for each of its coal-fired generating units and what the related retirement dates are for each of these units.

Response:

Please see STF-LA-1-38 Attachment for the service life and related depreciation study retirement dates that were approved by the Commission for ratemaking purposes in the 2022 Rate Case Order in Docket No. 44280 for each of the Company's coal-fired generating units. The Company will file a new depreciation study as part of the Company's next base rate case to address changes since the 2022 Rate Case.

STF-LA-1-38 Attachment

**Georgia Power Company
Coal-Fired Generating Units**

<u>Coal-Fired Generating Units</u>	<u>Life Span</u>	<u>Depreciation Study Retirement Date</u>
	(Note 1)	(Note 1)
<u>Plant Bowen</u>		
Unit 1	59	2030
Unit 2	58	2030
Unit 3	61	2035
Unit 4	60	2035
<u>Plant Scherer</u>		
Unit 1	46	2028
Unit 2	44	2028
Unit 3	41	2028

Note 1 - As approved by the Commission in Docket No. 44280