BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of:	**)**	
GEORGIA POWER COMPANY'S	**)**	**DOCKET NO. 44280**
2022 RATE CASE	**)**	

DIRECT TESTIMONY
AND EXHIBITS
OF
RALPH C. SMITH
AND
ROBERT L. TROKEY

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

PUBLIC VERSION

October 20, 2022

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

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RS/RT-14	Georgia Power's response to STF-LA-2-120 concerning Electric Vehicles Community Charging Stations.
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RS/RT-17	Georgia Power's 2021 FERC Form 1, pages 214, account 105, Plant Held for Future Use.

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RS/RT-21	Selected pages of Southern Company Services FERC Form 60 for period of 2021 Q4 (cover, pages 307, 402).
RS/RT-22	Georgia Power's Trade Secret response to STF-LA-2-111 (without attachment) concerning SCS Allocation Factors Using 2022 Statistics.
RS/RT-23	Selected pages of Southern Nuclear Operating Company FERC Form 60 for period of 2021 Q4 (cover, pages 307, 402).
RS/RT-24	Georgia Power's response to STF-LA-7-1 concerning DSM Carrying Costs.
RS/RT-25	Georgia Power's responses to STF-LA-2-101, 102, 115 and 116 concerning Excess Accumulated Deferred Income Taxes.
RS/RT-26	Georgia Power's responses to STF-LA-5-14, 5-15 and 8-13 concerning tax credits expected under the Inflation Reduction Act and impact of minimum corporate income tax provisions under that Act.
RS/RT-27	Georgia Power's response to STF-1-43 from Docket No. 44265 concerning SNOC's allocation percentages upon Plant Vogtle Units 3 and 4 being placed into service, currently projected to be March 2023 and December 2023, respectively.

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of:	**)**	
GEORGIA POWER COMPANY'S	**)**	**DOCKET NO. 44280**
2022 RATE CASE	**)**	

DIRECT TESTIMONY OF RALPH C. SMITH AND ROBERT L. TROKEY

I. INTRODUCTION

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

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

Q. WHAT IS YOUR OCCUPATION?

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

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit__(RCS-1). This exhibit summarizes my regulatory experience and qualifications.

Q. MR. TROKEY, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Robert L. Trokey, 244 Washington St. SW, Atlanta, Georgia 30334.

Q. WHAT IS YOUR OCCUPATION?

A. I am Director of the Electric Section at the Georgia Public Service Commission ("Commission").

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

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

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. We are testifying on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff ("Staff").

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY?

A. The scope and purpose of our testimony is to present the Staff's overall traditional case revenue requirement position for Georgia Power Company ("Georgia Power" or "Company"), as well as Staff's recommended position regarding the Company's proposed Alternative Rate Plan ("ARP"), and Environmental Compliance Cost Recovery ("ECCR").[1] We also show the Company's Demand Side Management ("DSM") revenue requirement, and Municipal Franchise Fee ("MFF") revenue requirement, as well as Staff's corresponding recommendations on each of those. We also address the Company's proposal for a three-year alternative rate plan covering the years 2023, 2024

[1] The annual Coal Combustion Residuals ("CCR") Asset Retirement Obligations ("ARO") revenue requirements for 2023, 2024 and 2025 are reflected in Georgia Power Exhibit__(APA/SPA/ADH/MBR-1, Schedule 3 ECCR).

and 2025, the history of previous Company rate plans, and recommendations for the principles and sharing mechanisms that should be applied, if the Commission chooses to allow for an alternative rate plan in the current rate cases, versus allowing a revenue requirement based on adjusted test year results.

Q. IN CALCULATING THE STAFF'S RECOMMENDED OVERALL TRADITIONAL RATE CASE REVENUE REQUIREMENT POSITION, DID YOU INCORPORATE RECOMMENDATIONS MADE BY OTHER STAFF WITNESSES?

A. Yes. We have incorporated the following recommendations of other Staff witnesses at this time:

- Ms. Jamie Barber's recommendations concerning the Company's *DSM revenue requirement* and adjustments thereto.
- Mr. Michael Gorman's recommended *capital structure*, *return on equity and cost rates for long-term debt.*
- Mr. Dante Mugrace's recommended adjustments to O&M expense.
- Mr. Steve Baron's and Ms. Leah Wellborn's recommended adjustments to forecasted revenues.
- Mr. Paul Alvarez's, Mr. Dennis Steven's and Mr. Raj Rana's recommended adjustments to Transmission and Distribution plant investment, and for the Distributed Energy Resource Management System.

Q. WHAT INFORMATION HAVE YOU RELIED UPON IN THE DEVELOPMENT OF YOUR TESTIMONY?

A. In developing this testimony, we have relied upon our review and analysis of the Company's direct testimonies and accompanying exhibits; Minimum Filing Requirements; workpapers; responses to "STF-L&A" and "STF-PIA" and other Staff data requests; transcripts from the September 27-29, 2022 hearings; and other relevant financial documents and data.

III. CASE OVERVIEW AND STRUCTURE OF TESTIMONY

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THIS CASE.

A. This case was filed by the Company on June 24, 2022, in accordance with the Procedural and Scheduling Order in Docket No. 44280, and the requirements of the Short Order Adopting Settlement Agreement As Modified approved by the Commission in its Order dated December 31, 2019, in Georgia Power's 2019 rate case, Docket No. 42516. Georgia Power filed the instant rate case to obtain a Commission decision regarding its base rates prior to the expiration of the Accounting Order on December 31, 2019.

Q. WHAT TEST PERIOD AND PLAN YEARS ARE USED IN THE COMPANY'S FILING?

A. The Company's rate filing includes financial projections for the traditional, Commission-ordered test year of August 1, 2022 through July 31, 2023, as well as for an Alternative Rate Plan that encompasses the three calendar years 2023, 2024 and 2025.

Q. WHAT CUMULATIVE BASE RATE REVENUE INCREASES HAS THE COMPANY PROPOSED FOR THE ALTERNATIVE RATE PLAN YEARS 2023-2025?

A. The Company has proposed cumulative base rate revenue increases of approximately $2.9 billion, which includes traditional base rates, ECCR, DSM and MFF,[2] over the 2023-2025 alternative rate plan period as shown in the table below.

[2] See Table A on page 10.

Description	2023 ($ Millions)	2024 ($ Millions)	2025 ($ Millions)	3 Year Total ($ Millions)
Company As-Filed Projected Revenue Requirement Deficiency by Year	$ 599	$ 927	$ 1,330	$ 2,854

Traditional Base Rates

Q. HOW DID THE COMPANY PROPOSE TO RECOVER THE REVENUE DEFICIENCY FOR THE TEST YEAR ENDING JULY 31, 2023?

A. The rate filing indicates that the Company requests a revenue requirement increase of approximately $738.661 million rather than the $447.521 million revenue deficiency associated with the test year. The $738.661 million is based on a $426.415 million "levelized" revenue deficiency which the Company calculated based on calendar 2023 through 2025. This is shown on Company Exhibit__(APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1 of 3. As shown there, Georgia Power first calculated a retail jurisdictional revenue deficiency for the test year of approximately $312.245 million. To that amount the Company added a "2023-2025 Levelization Adjustment" amount of $426.415 million[3], to derive its requested Levelized Revenue Deficiency Applicable to Traditional Base Rate Tariffs of $738.661 million, as shown on Company Exhibit__(APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1, lines 1-3.

Q. IS THE COMPANY'S PROPOSED RECOVERY OF A REVENUE DEFICIENCY BASED ON THE TRADITIONAL TEST YEAR APPROACH?

A. No. The Company's rate request in this case is not based on the traditional ratemaking approach. Rather, it is based on an Alternative Rate Plan that uses projected data from an

[3] In the context of a traditional rate case, the Company has not provided any authority for allowing recovery of a "Levelization Adjustment" based on costs from future years beyond the Commission ordered test year.

alternative test year, calendar year 2023, as well as projections for calendar years 2024 and 2025. While the proposed Alternative Rate Plan has no termination date, the rate filing presents projected revenue requirement and associated rate change data for the first three years of the Plan, i.e., the years 2023, 2024 and 2025. This approach is very beneficial to the Company as it eliminates regulatory lag. The Company is only entitled to rates being set under the test year. Of course, if rates are set on a test year the Company may stay out as long as it wants and may file a rate case at any time. The Commission has the authority to order the Company to file a rate case at any time.

The revenue deficiency calculated by the Company (excluding the MFF) for the test year is $447.521 million as shown on Company Exhibit __ (APA/SPA/ADH/MBR-2, Schedule 1 Total Company), page 1 of 10.

The revenue deficiencies calculated by the Company (excluding the MFF) under the Alternative Rate Plan amount to approximately $584.204 million for 2023, $905.447 million for 2024 and $1.299 billion for 2025 as shown on Company Exhibit __ (APA/SPA/ADH/MBR-2, Schedule 1 Total Company), page 1 of 10.

As shown on Company Exhibit __(APA/SPA/ADH/MBR-2, Schedule 2, Traditional Base), page 3 of 3, the Company has calculated a traditional base rate tariff revenue deficiency of $461.367 million for 2023; a $717.966 million deficiency for 2024 and a $1.080 billion revenue deficiency for 2025.

As shown on Company Exhibit __ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 2 of 3, the Company proposes to "levelize" the traditional base rate tariff revenue deficiency of $461.367 million for 2023; a $717.966 million deficiency for 2024 and a $1.080 billion revenue deficiency for 2025, using a discount rate of 7.32%, to produce a "levelized" annual revenue deficiency of $738.661 million for 2023, 2024 and 2025.

As shown on Company Exhibit __ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1 of 3, the Company proposes to adjust its calculated test year revenue requirement deficiency of $312.245 million under traditional base rate tariffs upward by $426.415 million to get to the 2023, 2024 and 2025 "levelized" revenue deficiency of $738.661 million per year. This is shown on Company Exhibit __ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 2 of 3, lines 1 through 3. This means that, under Georgia Power's proposal, the traditional base rates to become effective on January 1, 2023 will be designed to recover a revenue deficiency of $738.661 million per year, which is $426.415 million more than the $312.245 million revenue deficiency that the Company calculated for the test year.[4]

Q. WHAT AMOUNT OF BASE RATE REVENUE DEFICIENCY HAS THE COMPANY PROPOSED FOR NEW RATES TO BECOME EFFECTIVE ON

[4] The Company's calculated test year revenue deficiency of $312.245 million for traditional base rate tariffs is shown on Company Exhibit__ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1 of 3, line 1; on page 2 of 3, line 3, and on page 3 of 3, column (3), line 4.

JANUARY 1, 2023, AND HOW DOES THAT COMPARE WITH THE TEST YEAR AMOUNT?

A. As shown in Company Exhibit__ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1 of 3, the 2023-2025 "Levelized Revenue Deficiency" applicable to traditional base rates of $426.415 million (from line 2) is added to the $312.245 million for traditional base rate tariffs to produce a combined revenue deficiency of $738.661 million.

That $738.661 million is $426.415 million higher than the $312.245 million test year revenue deficiency applicable to traditional base rates that the Company shows on Exhibit__ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 3 of 3, line 4.

Q. WHAT AMOUNT OF BASE RATE REVENUE INCREASES HAS THE COMPANY CALCULATED FOR THE TEST YEAR AND EACH PLAN YEAR?

A. Company Exhibit __(APA/SPA/ADH/MBR-1, Schedule 1 Total Company) page 1 of 10 shows Georgia Power's computation of the retail revenue increases applicable to base rate tariffs including ECCR and DSM, excluding the MFF for the test year and each plan year as follows:

- Test Period: $447.521 million
- 2023: $584.204 million
- 2024: $905.447 million
- 2025: $1.299 billion

With the MFF included, the Company's calculated revenue requirement deficiency amounts by year for the 2023 through 2025 plan years is summarized from Table 2 at page 21 of the Abramovitz/Adams/Houston/Robinson panel testimony as follows:

Table A - Company As-Filed Projected Revenue Requirement Deficiency

Company As-Filed Projected Revenue Requirement Deficiency by Year (In Millions of Dollars)				
Effective Date	2023	2024	2025	3 Year Total
Traditional Base (a)	$ 461	$ 718	$ 1,080	$ 2,259
ECCR				
ECCR Traditional (b)	$ 29	$ (12)	$ (25)	$ (8)
ECCR CRO ARO* (c)	$ 64	$ 143	$ 189	$ 396
DSM* (d)	$ 30	$ 56	$ 54	$ 140
MFF (e)	$ 14	$ 22	$ 31	$ 67
Total ($)	$ 599	$ 927	$ 1,330	$ 2,854
* As determined by the Commission through annual CCR ARO and DSM compliance filings				
Note: Amounts may not sum to total due to rounding				
Source: Abramovitz/Adams/Houston/Robinson Direct Testimony, page 21, Table 2				
See the following exhibits supporting Table A:				
(a) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base) Page 3				
(b) Exhibit_ (APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 2				
(c) Exhiibt__(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 6				
(d) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 4 DSM) Page 1				
(e) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 5 MFF) Page 2				

Q. DOES TABLE A REPRESENT THE RATE INCREASES THAT THE COMPANY IS SEEKING?

A. No. The rate increases for the 2023, 2024 and 2025 plan years that the Company is seeking are summarized below from Table 1 from page 9 of the Abramovitz/Adams/Houston/Robinson panel testimony, with three-year totals also shown:

Table B - Company As-Filed Proposed Rate Adjustments

Company Proposed Rate Adjustments (in millions) - Company As-Filed				
Effective Date	1/1/2023	1/1/2024	1/1/2025	3 Year Total
Traditional Base (a)	$ 739	$ -	$ -	$ 739
ECCR				
ECCR Traditional (b)	$ (1)	$ -	$ -	$ (1)
ECCR CRO ARO* (c)	$ 64	$ 78	$ 47	$ 189
DSM* (d)	$ 30	$ 27	$ (2)	$ 55
MFF (e)	$ 20	$ 2	$ 1	$ 23
Total ($)	$ 852	$ 107	$ 45	$ 1,004
Cumulative ($)	$ 852	$ 959	$ 1,004	$ 2,815
* As determined by the Commission through annual CCR ARO and DSM compliance filings				
Note: Amounts may not sum to total due to rounding				
Source: Abramovitz/Adams/Houston/Robinson Direct Testimony, page 9, Table 1				
See the following exhibits supporting Table A:				
(a) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base) Page 1				
(b) Exhibit_ (APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 1				
(c) Exhiibt__(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 6				
(d) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 4 DSM) Page 1				
(e) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 5 MFF) Page 1				

Q. HAS THE COMPANY FILED A SUPPLEMENTAL FILING THAT HAS CHANGED ITS REVENUE DEFICIENCY AMOUNTS?

A. Yes. On August 22, 2022, the Company filed a supplemental that had the overall net effect of increasing the Company's proposed January 1, 2023, 2024 and 2025 rate adjustments by approximately $37 million (from $852 million for 2023 to $889 million) for 2023; by $37 million for 2024 (from $959 million to $996 million) and by $37 million for 2025 (from $1.004 billion to $1.041 billion). The Company's corrected rate changes are summarized in the following table, which also shows three-year totals for the 2023-2025 alternative rate plan years:

Table C - Company Updated Proposed Rate Adjustments

Company Proposed Rate Adjustments (in millions) - Company Supplemental				
Effective Date	1/1/2023	1/1/2024	1/1/2025	3 Year Total
Traditional Base (a)	$ 762	$ -	$ -	$ 762
ECCR				
ECCR Traditional (b)	$ 5	$ -	$ -	$ 5
ECCR CRO ARO* (c)	$ 64	$ 78	$ 47	$ 189
DSM* (d)	$ 37	$ 27	$ (2)	$ 62
MFF (e)	$ 21	$ 2	$ 1	$ 24
Total ($)	$ 889	$ 107	$ 45	$ 1,042
Cumulative ($)	$ 889	$ 996	$ 1,041	$ 2,926
Cumulative ($) Company As-Filed	$ 852	$ 959	$ 1,004	$ 2,815
Change from Company As-Filed	$ 37	$ 37	$ 37	$ 111
* As determined by the Commission through annual CCR ARO and DSM compliance filings				
Note: Amounts may not sum to total due to rounding				
Source: Supplemental Filing Transmittal Letter Dated August 22, 2022, Page 2				

Q. HAS THE COMPANY INDICATED WHAT CAUSED THE SUPPLEMENTAL CHANGES?

A. Yes. As discussed in the Company's Supplemental Filing transmittal letter, the Company's supplemental filing reflects the revenue requirement impacts from various items included in the Final Order that was approved by the Commission in Georgia Power's 2022 Integrated Resource Plan ("2022 IRP") and DSM Certification proceedings in Docket Nos. 44160 and 44161.

Q. WHAT SPECIFIC CORRECTIONS ARE REFLECTED IN GEORGIA POWER'S SUPPLEMENTAL FILING?

A. The Company's transmittal letter lists the following revenue requirement impacts in its Errata filing:

- Defer Retirement Decision on Plant Bowen Units 1&2

- Update Plant Scherer ELG Capital Cost
- Update Capacity RFP PPA Additional Sum
- Update DG PPA Additional Sum
- Remove Wholesale to Retail Capacity Offer of 88 MWs related to Plant Yates Units 6&7 and Blocks 5&6
- Remove North Highlands Hydro Modernization Project
- Include DER Local Reliability and Constraints Pilot Projects
- Remove Tall Wind Research and Development Project
- Update DSM costs and additional sum, along with revenue impacts from the revised energy savings targets

Q. HAVE THE ALL THE IMPACTS FROM THE COMPANY'S SUPPLEMENTAL FILING BEEN REFLECTED IN STAFF'S CALCULATIONS?

A. Yes. Since Staff's analysis used as a starting point the Company's original filing, the Company's supplemental filing corrections have been reflected by Staff as adjustments. Specifically, Exhibit__(RS/RT-2) reflects the rate base adjustments from the Company's supplemental filing on Schedule E-1 and operating income adjustments from the supplemental filing on Schedule E-2.

Q. WILL GEORGIA POWER CUSTOMERS ALSO BE FACING OTHER SIGNIFICANT INCREASES IN THEIR ELECTRIC UTILITY BILLS OVER THE 2023-2025 ALTERNATIVE RATE PLAN PERIOD?

A. Yes. Customers will see their bills increase due not only to the base rate increase(s) for 2023-2025 under the alternative rate plan that are being addressed in the current Georgia Power rate case, and also will likely face other significant rate increases for the Company's recovery of fuel and purchased power costs, and additional rate increases related to Plant Vogtle Units 3 and 4 being placed into service, which is currently expected to occur prior to the end of the alternative rate plan period of 2023-2025. Staff's estimates to a typical residential customer based on what the Company may request for those additional increases could be as much as an additional $25 per month for fuel rates, an additional $5 per month for Vogtle Unit 3 and an additional $10 to $15 per month for Vogtle Unit 4, respectively.

Q. HOW IS THE REST OF YOUR TESTIMONY STRUCTURED?

A. The rest of our testimony is structured into several sections where various issues are addressed.

Section IV presents a summary of the Company's and Staff's recommended revenue requirement as determined based on the traditional ratemaking approach using the traditional test year August 1, 2022 through July 31, 2023 as well as for each of the plan years, 2023, 2024 and 2025, which are presented in Exhibit__(RS/RT-2).

Section V discusses the Environmental Compliance Cost Recovery tariff revenue deficiency proposed by the Company and calculated by Staff. Staff's calculation of the ECCR revenue requirement for the test year and each plan year is shown in

Exhibit__(RS/RT-3). This section also discusses how the Company's requested ECCR amount affects the revenue requirement, and Staff's recommended proposal.

Section VI of our testimony presents a summary of the DSM tariff revenue deficiency amounts for 2023, 2024 and 2025 using information from Docket Nos. 44160 and 44161 and supplied to us by Staff witness Jamie Barber. Staff's calculations of the DSM revenue deficiency amounts are shown in Exhibit__(RS/RT-4) and also reflect the application of Staff's recommended cost of capital in the calculation of carrying charges.

Section VII presents a summary of the MFF tariff revenue requirement, which is shown in Exhibit__(RS/RT-5), and the impacts of the pre-tax cost of capital and the traditional base rate, ECCR and DSM revenue deficiency amounts on the MFF revenue requirement deficiency that was proposed by the Company and as calculated by Staff.

Section VIII discusses the Company's proposed and Staff's adjusted revenue requirement for Coal Combustion Residuals ("CCR") Asset Retirement Obligations ("ARO") which are presented in Exhibit__(RS/RT-6).

Section IX discusses the organization of Staff's revenue requirement and adjustment schedules which are presented in Exhibit__(RS/RT-2) for the traditional rate case based on the test year ending July 31, 2023 and for each year, 2023-2025, in the alternative rate plan.

Section X discusses each of Staff's recommended adjustments that are shown in Exhibit __(RS/RT-2) on Schedules E-1 through E-38 and some areas that were reviewed by Staff but for which no adjustment is being made to the Company's filing.

Section XI addresses affiliate transactions including the charges between Georgia Power Company and its affiliates including Southern Company Services ("SCS") and Southern Nuclear Operating Company ("SNOC") charges to Georgia Power; and Georgia Power charges to affiliates.

Section XII addresses the incentive compensation plans of Georgia Power Company and affiliates, which includes stock-based compensation and the Performance Pay Plan.

Section XIII explains Staff's proposed principles and recommendations for the Alternative Rate Plan. This section includes a discussion of Staff's proposed earnings test, as well as Staff's recommendation that a step increase approach be used instead of the levelization approach that has been proposed by Georgia Power Company.

Finally, Section XIV presents a summary of recommendations.

Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. In addition to our qualifications, which are in Exhibit RCS-1 and RLT-1, respectively, Staff has attached Exhibits RS/RT-2 through RS/RT-27 which contain responses to discovery and other materials referenced in our testimony.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-2?

A. Exhibit RS/RT-2 presents Staff's calculations relating to the Traditional Revenue Requirement and Adjustment Schedules.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-3?

A. Exhibit RS/RT-3 presents Staff's calculations concerning the ECCR Revenue Requirement.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-4?

A. Exhibit RS/RT-4 presents Staff's calculations concerning the DSM Revenue Requirement.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-5?

A. Exhibit RS/RT-5 presents Staff's calculations concerning the Municipal Franchise Fee Revenue Requirement.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-6?

A. Exhibit RS/RT-6 presents Staff's calculations concerning the CCR ARO Compliance Revenue Requirement.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-7?

A. Exhibit RS/RT-7 presents Georgia Power's responses to STF-LA-2-79, STF-LA-2-81, and STF-LA-2-92 and Trade Secret response to STF-LA-2-78 concerning Stock-Based Compensation.

Q. WHAT ARE SHOWN IN EXHIBITS RS/RT-8, RS/RT-9, AND RS/RT-10?

A. Exhibit RS/RT-8 presents Georgia Power's responses to STF-LA-3-1, STF-LA-3-2, STF-LA-3-3, and STF-LA-3-4 concerning Energy Direct Premium Packages.

Exhibit RS/RT-9 presents Georgia Power's response to STF-LA-2-56 concerning Executive Financial Planning.

Exhibit RS/RT-10 presents Georgia Power's response to STF-LA-2-25 concerning O&M Scrap Sales Proceeds.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-11?

A. Exhibit RS/RT-11 presents Georgia Power's Trade Secret response to STF-LA-12-1 concerning Wireless Co-Location Revenues.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-12?

A. Exhibit RS/RT-12 presents Georgia Power's response to STF-LA-8-18 concerning Depreciation Expense.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-13?

A. Exhibit RS/RT-13 presents Georgia Power's responses to STF-LA-6-19, STF-LA-6-20, STF-PIA-1-3, STF-PIA-3-5, HR-1 and the Trade Secret response to STF-PIA-1-1 concerning Electric Vehicles Make Ready Program.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-14?

A. Exhibit RS/RT-14 presents Georgia Power's response to STF-LA-2-120 concerning Electric Vehicles Community Charging Stations.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-15?

A. Exhibit RS/RT-15 presents Georgia Power's Trade Secret responses to STF-PIA-4-4 and STF-WG-2-33 concerning Transmission and Distribution Plant Investment.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-16?

A. Exhibit RS/RT-16 presents Georgia Power's Trade Secret response to STF-WG-2-3 concerning DERMS.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-17?

A. Exhibit RS/RT-17 presents Georgia Power's 2021 FERC Form 1, pages 214, account 105, Plant Held for Future Use.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-18?

A. Exhibit RS/RT-18 identifies amounts in the PHFFU account for which the projected "use" date in providing electric service is (1) 2030 or beyond or (2) 2040 or beyond.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-19?

A. Exhibit RS/RT-19 presents Georgia Power's response from Docket Nos. 44160 and 44161 (2022 IRP) to STF-LA-1-44 concerning PHFFU.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-20?

A. Exhibit RS/RT-20 presents Georgia Power's responses to STF-LA-2-117, STF-LA-2-118, and STF-LA-2-119 concerning Production Tax Credits.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-21?

A. Exhibit RS/RT-21 presents Selected pages of Southern Company Services FERC Form 60 for period of 2021 Q4 (cover, pages 307, 402).

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-22?

A. Exhibit RS/RT-22 presents Georgia Power's Trade Secret response to STF-LA-2-111 (without attachment) concerning SCS Allocation Factors Using 2022 Statistics.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-23?

A. Exhibit RS/RT-23 presents Selected pages of Southern Nuclear Operating Company FERC Form 60 for period of 2021 Q4 (cover, pages 307, 402).

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-24?

A. Exhibit RS/RT-24 presents Georgia Power's response to STF-LA-7-1 concerning DSM Carrying Costs.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-25?

A. Exhibit RS/RT-25 presents Georgia Power's responses to STF-LA-2-101, 102, 115 and 116 concerning Excess Accumulated Deferred Income Taxes.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-26?

A. Exhibit RS/RT-26 presents Georgia Power's responses to STF-LA-5-14, 5-15 and 8-13 concerning tax credits expected under the Inflation Reduction Act and the Company's estimated impact of minimum corporate income tax provisions under that Act.

Q. WHAT IS SHOWN IN EXHIBIT RS/RT-27?

A. Exhibit RS/RT-27 presents Georgia Power's response to STF-1-43 from Docket No. 44265 concerning SNOC's allocation percentages upon Plant Vogtle Units 3 and 4 being placed into service, currently projected to be March 2023 and December 2023, respectively.

IV. TRADITIONAL REVENUE REQUIREMENT SUMMARY

Test Year and Plan Years

Q. WHAT TEST YEAR SHOULD BE USED TO DETERMINE THE COMPANY'S TRADITIONAL REVENUE REQUIREMENT IN THIS CASE?

A. Under the Commission's February 6, 2020 Order Adopting Settlement Agreement as Modified in Docket No. 42516, the test period to be used in this case is from August 1, 2022 to July 31, 2023. The February 6, 2020 Order Adopting Settlement Agreement as Modified also required the Company to file testimony and exhibits required in a general rate case along with supporting schedules required by the Commission to support a "traditional" rate case by July 1, 2022, so that the Commission may consider whether to continue, modify, or discontinue the Alternative Rate Plan established in Georgia Power Company's 2019 Rate Case, Docket No. 42516 ("2019 Rate Case").

Both the Company and Staff have presented revenue requirement calculations using the test year ending July 31, 2023, as well as for calendar years 2023, 2024 and 2025, which comprise the Company's Alternative Rate Plan presentation in the current rate case.

Q. WHAT IS THE DIFFERENCE BETWEEN THE COMPANY'S CALCULATED REVENUE DEFICIENCY FOR THE TEST YEAR ENDED JULY 31, 2023 AND FOR CALENDAR YEAR 2023?

A. The Company's calculated a traditional base rate revenue deficiency of $312.245 million[5] for the test year ended July 31, 2023 is approximately $426.415 million less than its requested revenue increase amount for the calendar year 2023 of $738.661 million, as shown on Company Exhibit__ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1 of 3, lines 1 through 3.

That $738.661 million base rate revenue increase that the Company has requested to become effective on January 1, 2023 based on its proposed alternative rate plan is $426.415 million more than the amount of the Company's calculated test year revenue deficiency applicable to traditional base rate tariffs of $312.245 million, which is shown on Company Exhibit__ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 3 of 3, column 3, line 4.

Traditional Case Summary

Q. PLEASE SUMMARIZE STAFF'S FINDINGS AND CONCLUSIONS REGARDING GEORGIA POWER'S TRADITIONAL REVENUE REQUIREMENT BASED ON THE COMMISSION-ORDERED TEST YEAR ENDING JULY 31, 2023.

A. Our findings and conclusions are as follows:

1. The traditional revenue requirement for Georgia Power in this rate case should be determined based on the use of the Commission-ordered test year ending July 31, 2023.

[5] This amount does not include ECCR, DSM and MFF.

2. The appropriate traditional test year average retail rate base is $24.039 billion which is $21.265 million higher than the Company's proposed traditional test year average retail rate base of $24.018 billion as shown on Staff Exhibit__(RS/RT-2), Schedule A, line 1 and Schedule B.[6]

3. The appropriate traditional test year retail operating income is $1.709 billion, which is $193.069 million higher than the Company's proposed test year traditional test year retail operating income of $1.516 billion as shown on Staff Exhibit__(RS/RT-2), Schedule A, line 4 and Staff Exhibit__(RS/RT-2), Schedule C.

4. The traditional test year overall rate of return for Georgia Power we used in this case is 6.84% as summarized on Staff Exhibit__(RS/RT-2), Schedule D and includes a fair return on equity of 9.45% and the 3.53% cost of debt as recommended by Staff witness Michael Gorman. Staff's overall cost of capital of 6.84% for the test year compares to Georgia Power's proposed overall rate of return of 7.70%, which includes a requested return on equity rate of 11.0%.

5. The appropriate income expansion factor (aka Gross Revenue Conversion Factor or GRCF) to be used for ratemaking purposes in this case is dividing by 74.606% or multiplying by 1.340378, as shown on Staff Exhibit__(RS/RT-2), Schedule A-1, page 1 of 2. This percentage compares with the Company's proposed factor of 74.606%. This factor reflects a federal income tax rate of 21% and a state income tax rate of 5.75%. The same income tax rates were used by both Georgia Power

[6] The rate base difference is impacted by various adjustments.

and Staff; however, Staff's factor is slightly lower than the Company's because Staff reflects a lower component for uncollectibles.

6. The recommended traditional test year ratemaking components outlined above would produce an annual Traditional Base Rate Tariff decrease (i.e., a revenue excess amount) of approximately $86.581 million. This is $534.102 million lower than Georgia Power's proposed traditional test year Traditional Base Rate Tariff deficiency of $447.521 million. These amounts are shown on Staff Exhibit __(RS/RT-2), Schedule A, line 7, in columns C, A, and G, respectively.

7. Georgia Power's proposed ECCR Tariff rider revenue deficiency has been adjusted by Staff as shown on Staff Exhibit__(RS/RT-3), and discussed in Section V of our testimony. While Georgia Power has proposed an ECCR Tariff revenue increase of $105.6 million for the test year, Staff has calculated a test year ECCR Tariff revenue deficiency of $68.9 million. The Company also proposed a "levelization" adjustment for the ECCR. Staff does not recommend a levelization adjustment for the ECCR. Without the levelization adjustment, Staff's recommended ECCR revenue deficiency of $68.9 million is about $36.7 million lower than the Company's proposed amount of $105.6 million. See Staff Exhibit__(RS/RT-2), Schedule A, line 8, columns A, C and G and Staff Exhibit__(RS/RT-3).

8. Georgia Power has proposed continuation of its DSM Tariff rider with an associated DSM Tariff revenue deficiency of $29.65 million for the traditional test year. Staff calculated a $36.98 million DSM revenue deficiency, which is about $7.3 million higher than the Company amount. See Staff

Exhibit__(RS/RT-2), Schedule A, line 9, columns A, C and G and Staff Exhibit__(RS/RT-4).

9. For the CCR ARO Compliance revenue requirement, Staff calculated $57.8 million for the test year and $61.7 million for 2023, as shown on Exhibit __(RS/RT-6). These amounts compare with, and are lower by $2.3 million and $2.8 million, respectively, than the Company's proposed test year amount of $60.0 million and the Company's proposed 2023 amount of $64.5 million. See Exhibit__(RS/RT-6), pages 2 and 3. For CCR ARO Compliance, Staff recommends using the 2023 revenue deficiency amount of $61.7 million, as shown on Exhibit__(RS/RT-6), page 3.

10. Staff recommends that the Company's proposed 2023-2025 levelization revenue requirement adjustment of $426.415 million to derive a levelized revenue deficiency amount of $738.661 million per year for 2023-2025 not be adopted. Rather, Staff recommends that a step-increase approach be used for a three-year rate plan. Staff Exhibit__(RS/RT-2), Schedule A, line 13, shows the calculated increases for 2024 and 2025. The Company should be required to file compliance filings prior to implementing step increases in each of those years, 2024 and 2025.

Staff Test Year and Plan Year Adjustments-Estimated Revenue Requirement Impacts

Q. HAVE YOU PREPARED A TABLE OUTLINING THE APPROXIMATE REVENUE REQUIREMENT IMPACT OF EACH OF STAFF'S RECOMMENDED ADJUSTMENTS TO THE COMPANY'S PROPOSED TRADITIONAL REVENUE REQUIREMENT IN THIS CASE FOR THE TEST YEAR AND EACH PLAN YEAR?

A. Yes, Table D is presented on the next page of this testimony from amounts that are shown in more detail on Staff Exhibit__(RS/RT-2), Schedule A-2, pages 1 through 4:

Table D - Summary of Staff Traditional Base Rate Revenue Requirement Adjustments

Georgia Power Company
Revenue Requirement Impact Summary (Also See Exhibit __(RS/RT-2), Schedule A-2)
Summary of Staff Adjustments and Adjusted Revenue Deficiency (Sufficiency)
(Thousands of Dollars)

Line No.	Description	Staff Exh__(RS/RT-2) Detail Adjustment Schedules	Forecasted Test Year Ending 7/31/2023	Calendar 2023	Calendar 2024	Calendar 2025
1	Company Calculated Revenue Requirement Deficiency		$ 447,521	$ 584,204	$ 905,447	$ 1,299,024
	Staff Adjustments:					
2	Return on Equity (9.45% vs. 11.00%), Capital Structur and Cost of Debt	A-2	$ (277,265)	$ (292,322)	$ (419,429)	$ (442,745)
3	Adjustments and Corrections from GPC Supplemental/Update Filing*	E-1 & E-2	$ 12,134	$ 27,919	$ 42,435	$ 41,160
4	Stock-Based Compensation	E-4	$ (29,211)	$ (29,102)	$ (26,971)	$ (28,272)
5	Depreciation Expense and Accumulated Depreciation	E-12	$ (30,033)	$ (51,698)	$ (50,008)	$ (47,074)
6	Property Tax Expense	E-37	$ -	$ (2,269)	$ (7,230)	$ (12,745)
7	Transmission Plant Investment	E-30	$ -	$ (15,013)	$ (42,673)	$ (72,735)
8	Distribution Plant Investment	E-31	$ -	$ (15,048)	$ (46,078)	$ (80,017)
9	Intangible Plant Investment	E-32	$ -	$ (456)	$ (2,630)	$ (6,613)
10	Transmission Plant - Depreciation Expense and Accumulated Depreciation	E-33	$ -	$ (3,820)	$ (10,975)	$ (17,786)
11	Distribution Plant - Depreciation Expense and Accumulated Depreciation	E-34	$ -	$ (4,544)	$ (14,095)	$ (23,279)
12	Distributed Energy Resource Management System (DERMS) - Amortization and Accumulated Amortization	E-35	$ -	$ (950)	$ (5,630)	$ (13,673)
13	Depreciation Expense - Depreciation Rates Correction for Ft Benning and Ft Gordon	E-36	$ 1,188	$ 2,036	$ 2,036	$ 2,036
14	Income Tax Credits Related to the Inflation Reduction Act	E-38	$ -	$ (42,492)	$ -	$ (536)
	Fall-Out Impacts from Other Adjustments:					
15	Interest Synchronization	E-8	$ 802	$ 1,903	$ (10,224)	$ (7,271)
16	Cash Working Capital	E-10	$ (367)	$ (92)	$ (194)	$ 27
17	Payroll Tax Expense	E-5	$ (2,234)	$ (2,226)	$ (2,064)	$ (2,162)
18	Difference Due to Staff using a different Gross Revenue Conversion Factor	A-1, A-2	$ (1)	$ -	$ -	$ -
	Other Staff Adjustments:					
18	Executive Financial Planning	E-7	$ (468)	$ (468)	$ (467)	$ (467)
19	Forecasted Revenues	E-3	$ (5,999)	$ (5,705)	$ (4,874)	$ (7,763)
20	Wireless Co-Location Revenues	E-11	$ (404)	$ (434)	$ (521)	$ (628)
21	Energy Direct Premium Packages	E-6	$ (1,166)	$ (1,177)	$ (1,210)	$ (1,242)
22	EV Investment	E-13, E-14 & E-15	$ -	$ (4,298)	$ (8,068)	$ (11,857)
23	O&M Scrap Sales Proceeds	E-9	$ (1,217)	$ (1,217)	$ (1,217)	$ (1,217)
24	O&M Expense - Transmission	E-16	$ (10,693)	$ (4,183)	$ (3,223)	$ (3,918)
25	O&M Expense - Distribution	E-17	$ (23,624)	$ 5,410	$ (328)	$ (7,151)
26	O&M Expense - Customer Accounting	E-18	$ (16)	$ 1,305	$ (5,116)	$ (8,252)
27	O&M Expense - Demonstration & Selling Expenses	E-19	$ (1,189)	$ (1,217)	$ (1,219)	$ (1,221)
28	O&M Expense - Administrative & General Salaries	E-20	$ (253)	$ (184)	$ (83)	$ (25)
29	O&M Expense - Office Supplies and Expense	E-21	$ (3,128)	$ -	$ -	$ -
30	O&M Expense - Outside Services Employed	E-22	$ (7,100)	$ 941	$ 2,322	$ (3,263)
31	O&M Expense - Injuries and Damages	E-23	$ (1,642)	$ 623	$ (1,287)	$ (1,539)
32	O&M Expense - Employee Pensions and Benefits	E-24	$ (13,676)	$ (13,517)	$ (13,235)	$ (12,956)
33	O&M Expense - Customer Service and Information	E-25	$ (17,023)	$ (20,028)	$ (16,024)	$ (9,013)
34	O&M Expense - Miscellaneous General and Advertising	E-26	$ (5,943)	$ (6,131)	$ (4,242)	$ (2,414)
35	O&M Expense - Maintenance of General Plant	E-27	$ (1,823)	$ -	$ -	$ -
36	O&M Expense - Adjustment for Inflation	E-28	$ -	$ (15,458)	$ (27,374)	$ (33,767)
37	Labor O&M Expense - Vacancy Rate, Employee Levels, Performance Pay Plan and Overtime	E-29	$ (113,750)	$ (101,536)	$ (72,662)	$ (92,984)
38	Staff Adjusted Rate Base Revenue Deficiency (Sum of lines 1 through 35 above)		$ (86,580)	$ (11,244)	$ 152,889	$ 387,659
39	Staff Adjusted Base Rate Revenue Deficiency (Excess)	A, A-2	$ (86,581)	$ (11,244)	$ 152,889	$ 387,659
40	Difference (rounding)		$ 0	$ 0	$ (0)	$ 0

* These adjustments do not include the interest synchronization or rate of return impacts

Based on Staff's calculations the Company has excess revenues of $86.6 million and $11.2 million in the test year and calendar year 2023, respectively. For calendar 2024 and 2025 the Company has revenue deficiencies of $152.9 million and $387.7 million,

respectively.[7] Each Staff adjustment is discussed in additional detail in Section X of our testimony.

Q. DOES STAFF RECOMMEND A LEVELIZED APPROACH FOR THE 2023–2025 PLAN YEAR REVENUE REQUIREMENT, AS PROPOSED BY GEORGIA POWER?

A. No. As explained in more detail elsewhere in our testimony, Staff recommends a step-increase approach for years 2024 and 2025, not a levelization.

Q. PLEASE SUMMARIZE STAFF'S RECOMMENDED REVENUE REQUIREMENT FOR THE TRADITIONAL TEST YEAR ENDING JULY 31, 2023 AND CALENDAR 2023, 2024 AND 2025.

A. As shown on Exhibit __(RS/RT-2), Schedule A, page 1, line 7, Staff's analysis shows that the Company has excess revenue at current rates for the traditional test year, and for calendar year 2023. Staff's analysis also shows the Company has a revenue deficiency for calendar years 2024 and 2025 at current rates. This is shown in detail on Staff Exhibit__(RS/RT-2), Schedule A, and Schedule A-2, pages 1 through 4.

[7] These values do not include MFF. Staff's calculated MFF revenue deficiencies are shown on Exhibit __(RS/RT-5) and are $4.7 million for the test year, $5.5 million for 2023, $14.1 million for 2024 and $21.8 million for 2025. If MFF is included, the Staff excess revenue amounts for the test year and 2023 would be reduced by the $4.7 million and $5.5 million MFF amounts, and the revenue deficiency amounts for 2024 and 2025 would be increased by the 2024 and 2025 MFF revenue deficiency amounts., respectively.

Q. IF STAFF'S ANALYSIS REFLECTS EXCESS REVENUE FOR THE TEST YEAR AND 2023, THEN WHY IS STAFF NOT RECOMMENDING A RATE DECREASE FOR 2023?

A. This is primarily based on considerations for rate stability. To avoid a reduction in rates on January 1, 2023 followed by what (other things being equal) would be a larger step increase in rates on January 1, 2024, Staff concluded that less fluctuation in rates would benefit ratepayers and the Company in this particular situation. Therefore, Staff recommends current rates be maintained through 2023. A step increase to be effective on January 1, 2024 should be addressed in a compliance filing to be made by the Company on October 1, 2023.

If the Company earns above the top end of the earnings band in 2023, as would be evaluated in the context of the Company's 2023 Annual Surveillance Report ("ASR"), Staff recommends that the excess should be used to recover deferred costs. Staff's proposed rate plan earnings band and sharing is addressed in additional detail in Section XIII of our testimony.

Q. WHAT IS STAFF'S RECOMMENDATION FOR ADDRESSING THE EXCESS REVENUES IN THE TRADITIONAL TEST YEAR AND CALENDAR 2023?

A. If the Commission concludes that the Company has excess revenue for the traditional test year and/or for calendar year 2023, as Staff shows, Staff recommends that the revenue excess be used for accelerated recognition of deferred costs in 2023 up to the amount of the revenue excess. As an illustration, Staff shows a base rate revenue excess of

approximately $86.6 million for the test year and $11.2 million for calendar year 2023.[8] On Exhibit__(RS/RT-2), Schedule B, pages 1 through 4, lines 35, 36 and 38 there are deferrals for various items that could be used for accelerated cost recognition, if the Commission concludes that the Company will have excess base rate revenues for 2023, as Staff has calculated. Some portion of these deferrals could potentially be recognized on an accelerated basis up to the amount of the revenue requirement excess associated with the excess earnings. That is, the excess revenues could be applied in 2023 to increase the amortization of the assets identified above. This could be done in the current rate case by making an adjustment, or determining the amount of excess earnings in 2023 could be reviewed in the context of the Company's 2023 ASR report, as described above.

[8] See, e.g., Exhibit__(RS/RT-2), Schedule A, columns C and D, respectively, line 7.

V. ECCR TARIFF REVENUE DEFICIENCY SUMMARY

Q. WHAT HAS THE COMPANY REQUESTED FOR THE ECCR?

A. The Company is requesting a "levelized" revenue sufficiency of $1.08 million plus a revenue deficiency of $64.49 million for CCR ARO compliance for an overall revenue deficiency of $63.31 million to be collected through the ECCR tariff in 2023. The ECCR amount requested by the Company is based on a levelized amount for the three-year period of 2023 through 2025 and thus, under the Company's proposal, the ECCR revenue requirement would not be expected to change from January 1, 2023 through December 31, 2025.

Q. WHAT IS THE BASIS FOR THE COSTS INCLUDED IN GEORGIA POWER COMPANY'S PROPOSED ECCR?

A. The Company's ECCR revenue requirements for the plan years 2023 through 2025 are reflected on Exhibit__(APA/SPA/ADH/MBR-1, Schedule 3 ECCR). The Company's Abramovitz/Adams//Houston/Robinson panel direct testimony indicates that those are based on the projected environmental investments and expenses associated with the ECCR tariff in 2023, 2024 and 2025. Those projections are described as being consistent with the Company's environmental strategy that was filed with the Commission in the Company's 2022 IRP proceeding, Docket No. 44160. The Company states that the projected costs it proposes to be recovered through the ECCR tariff are set based on the compliance strategy that was approved in the 2022 IRP process. Further, changes in those cost projections will not impact the ECCR tariff rate unless such changes are approved by the Commission.

Q. WHAT AMOUNTS OF ANNUAL ECCR REVENUE DEFICIENCIES HAS THE COMPANY CALCUATED FOR EACH YEAR?

A. Page 2 of Company Exhibit___(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) shows a revenue deficiency for the ECCR tariff of $28.7 million for 2023 and revenue excesses of $11.5 million and $24.5 million in calendar years 2024, and 2025, respectively. However, the amounts Georgia Power has requested in the proposed Alternate Rate Plan for the ECCR tariff would begin recovery of the combined 2023 through 2025 levelized calendar year amounts on January 1, 2023.

Q. DOES STAFF AGREE WITH GEORGIA POWER'S PROPOSED ECCR TARIFF REVENUE DEFICIENCY FOR THE TRADITIONAL TEST YEAR ENDING JULY 31, 2023 OR FOR THE PLAN YEARS 2023 THORUGH 2025?

A. Staff agrees with the continuation of the existing ECCR Tariff rider. However, Staff does not agree with the Company's proposed traditional test year ECCR Tariff revenue deficiency amount of $105.6 million, or with the Company's proposed ECCR revenue deficiency amounts for plan years 2023, 2024 or 2025.

Q. WHAT AMOUNT OF ECCR REVENUE DEFICIENCY DOES STAFF RECOMMEND FOR THE TEST YEAR?

A. As shown on Exhibit ___(RS/RT-3), page 3 of 12, Staff shows traditional test year ECCR Tariff revenue excess amounts of approximately $68.9 million, which is $36.7 million

lower than Georgia Power's proposed deficiency amount of $105.6 million. Staff is not recommending a levelized adjustment for the ECCR.

Q. HOW DO STAFF'S RECOMMENDED ECCR REVENUE DEFICIENCY AMOUNTS FOR THE PLAN YEARS 2023 THROUGH 2025 COMPARE WITH THE COMPANY'S REQUEST?

A. As shown on Exhibit ___(RS/RT-3), page 4 of 12, Staff's recommended ECCR revenue deficiency amounts for the plan years 2023 through 2025 are lower than the Company's requested amounts in each year.

- For 2023, the Staff ECCR recommended revenue deficiency is $60.6 million, which is about $32.6 million lower than the Company's calculated amount of $93.2 million.
- For 2024, the Staff ECCR recommended revenue deficiency is $91.0 million, which is about $40.0 million lower than the Company's calculated revenue excess amount of $131.0 million.
- For 2025, the Staff ECCR recommended revenue deficiency is $127.1 million, which is about $37.7 million lower than the Company's calculated revenue excess amount of $164.7 million.

Exhibit__(RS/RT-3), page 4 of 12 also shows differences related to the CCR ARO component on line 20.

Q. WHY ARE THE STAFF RECOMMENDED AMOUNTS OF ECCR DEFICIENCY LOWER THAN THE COMPANY CALCULATIONS?

A. As detailed on Exhibit __(RS/RT-3):

- Staff used a lower overall cost of capital based on the recommendations of Mr. Gorman;
- Staff reflected the impacts from the Company's supplemental filing;
- Staff's Income Expansion Factor for the test year differs slightly from the Company's due to an adjustment Staff has made to test year uncollectibles.

The calculations underlying Staff's recommended ECCR Tariff revenue deficiency amounts, and how they compare with Georgia Power's proposed amounts for the test year and for each plan year, 2023 through 2025, are shown on Staff Exhibit__(RS/RT-3).

Q. IS THE ECCR REVENUE REQUIREMENT AFFECTED BY THE RETURN ON EQUITY AND COST OF CAPITAL?

A. Yes. The cost of capital is an important input to the ECCR revenue requirement calculation.

Q. DOES STAFF'S PROPOSED COST OF CAPITAL DIFFER FROM THE COST OF CAPITAL REQUESTED BY GEORGIA POWER COMPANY?

A. Yes. As described in the testimony of Staff witness Gorman, Staff has recommended a 9.45% cost of equity. Mr. Gorman is recommending a capital structure that is different than the one requested by the Company. Each of these items affect the cost of capital. The result is that Staff is recommending an overall cost of capital for the future test year

and for each rate plan year, 2023 through 2025, that is lower than Georgia Power has requested.

Q. IS THE ECCR REVENUE REQUIREMENT IMPACTED BY OTHER ADJUSTMENTS?

A. Yes. The ECCR revenue requirement is also impacted by adjustments that affect environmental plant, depreciation, and O&M expense, as well as income taxes related to ECCR components, as shown on Exhibit __(RS/RT-3).

Q. HOW HAVE YOU INCORPORATED THOSE IMPACTS INTO THE ECCR REVENUE REQUIREMENT?

A. While the largest impact on the ECCR revenue requirement results from Staff's recommended cost of capital, other items affecting the ECCR have also been incorporated where such items could be readily identified from the details of the Company's errata filing and Staff's recommended adjustments.

Q. WHAT REVENUE REQUIREMENTS DOES STAFF SHOW FOR THE ECCR FOR THE FUTURE TEST YEAR AND FOR 2023, 2024, AND 2025?

A. As shown on Exhibit__(RS/RT-3), we have recalculated the ECCR revenue requirements for the forecasted test year and for each calendar year, 2023, 2024 and 2025 in the Company-proposed rate plan period. Staff's recalculated ECCR revenue requirements, and how they compare with the Company's request, are summarized below:

Table E: ECCR Revenue Requirement Deficiency - Staff and Company Compared

COMPUTATION OF RETAIL REVENUE DEFICIENCY
APPLICABLE TO ENVIRONMENTAL COMPLIANCE COST RECOVERY (ECCR) TARIFF
(Thousands of Dollars)

	Test Year	2023	2024	2025
Per Staff	$ 68,944	$ 60,578	$ 90,973	$ 127,067
Per Company	$ 105,626	$ 93,186	$ 131,004	$ 164,746
Difference	$ (36,682)	$ (32,608)	$ (40,031)	$ (37,679)

Source: Staff Exhibit__(RS/RT-3), pages 3 and 4

Q. DOES STAFF PROPOSE TO LEVELIZE THE ECCR REVENUE REQUIREMENTS?

A. No. Staff has not reflected a "levelization" of the 2023 through 2025 ECCR revenue requirements, similar to the Company's proposed $46.8 million decrease. Rather, Staff recommends that annual ECCR revenue deficiency (or excess) amounts for 2024 and 2025 be established based on compliance filings to be made by the Company on October 1, 2023 and 2024, respectively. Because the ECCR is a separately identifiable tariff component, annual adjustments can be made for the annual changes in the ECCR revenue requirement. Thus, Staff proposes that the ECCR revenue requirement be reflected as annual rate changes, rather than a levelized approach.

Q. PLEASE EXPLAIN WHAT AN EARNINGS TEST IS.

A. An earnings test reviews the Company's earnings, typically calculated with various adjustments to reflect ratemaking treatments. In the current alternative rate plan, for example, the Company reports its results for each year in an Annual Surveillance Report ("ASR"), which is reviewed by Staff. The Company's earnings are reviewed to determine if they were below, within or above an established earnings band. Staff's specific

recommendations for resetting the earnings band are addressed in a Section XIII of our testimony.

Q. DOES THE COMPANY'S ECCR PROPOSAL INCLUDE AN EARNINGS TEST?

A. No.

Q. DOES STAFF PROPOSE TO INCLUDE AN EARNINGS TEST AS PART OF ITS ECCR AND RATE PLAN RECOMMENDATIONS?

A. Yes. We discuss Staff's proposed earnings test for the Rate Plan period in Section XIII of our testimony.

VI. DSM TARIFF REVENUE DEFICIENCY SUMMARY

Q. HOW HAS STAFF REFLECTED THE DSM TARIFF REVENUE DEFICIENCY FOR THE TRADITIONAL TEST YEAR ENDING JULY 31, 2023 AND FOR CALENDAR YEAR 2023?

A. Staff supports the continuation of the existing DSM Tariff rider since the DSM program costs will be different each year and will vary by participation levels. For the test year and for calendar years 2023 through 2025, Staff has reflected a DSM tariff revenue deficiency in the following amounts, for which detailed calculations are shown on Exhibit ___(RS/RT-4);

- $36.9 million for the test year, which is about $7.3 million higher than the Company's requested $29.7 million.
- $37.0 million for 2023, which is about $7.4 million higher than the Company's requested $29.7 million.
- $64.0 million for 2024, which is about $7.5 million higher than the Company's requested $56.5 million.
- $62.1 million for 2025, which is about $8.1 million higher than the Company's requested $54.0 million.

Requiring the Company and Staff to agree on final program plans was part of a stipulation approved by the Commission in Docket Nos. 44160/44161. We are advised by Staff's DSM experts that these program plans will also drive the DSM revenue requirement for the plan years. The amounts for the 2024 and 2025 DSM revenue

requirements will ultimately be determined by the Commission through the Company's annual DSM filings.

Q. DOES THE DSM TARIFF REVENUE REQUIREMENT INCLUDE A COMPONENT FOR CARRYING COSTS ON DEFERRALS?

A. Yes. The Company's calculation of DSM carrying costs has been reproduced on Exhibit __(RS/RT-4), pages 9 and 10 of 17. The Staff's calculation of DSM carrying costs has been reproduced on that Exhibit on pages 11-12.[9] Pages 13-17 show the derivation of the Revenue Requirement carrying cost rate used by the Company and the comparable rates used by the Staff for the test year and for 2023, 2024 and 2025, respectively. The Staff carrying cost rates reflect Staff's recommended cost of capital.

[9] According to the response to STF-LA-7-1, the Company's carrying cost calculations include the correction of a transposition error in the carrying cost amounts reflected in Georgia Power's supplemental filing for the test period, 2023 and 2024. The transposition error did not impact 2025 carrying costs.

VII. MUNICIPAL FRANCHISE FEE TARIFF

Q. PLEASE PROVIDE SOME BACKGROUND ON THE COMPANY'S MFF TARIFF.

A. In the 2007 Georgia Power Rate Case Order, the Commission ordered the establishment of the MFF tariff in accordance with the Commission's Order in Docket No. 21112. The MFF tariff initially reflected 50 percent of MFF revenues being collected from customers located within municipal areas covered by a franchise agreement and 50 percent being collected from all customers, regardless of location. However, over the years, the Company has experienced a shift with more of its total revenue coming from customers within municipalities. Because the MFF tariff is a percentage rate and is calculated based on each customer's total bill before sales taxes are applied, the percentage rate does not have to be changed even if revenues change.

Q. WHAT CAUSES THE MFF TARIFFS TO CHANGE?

A. As described on pages 30-31 of the Abramovitz/Adams//Houston/Robinson Direct Testimony, the primary components of the MFF tariff that could change from year to year are the amount of revenues collected relative to whether or not customers are receiving service within a municipality's boundaries. As customer demographics change, so would the respective MFF tariff.

Q. WHAT HAS THE COMPANY REQUESTED FOR AN MFF TARIFF REVENUE REQUIREMENT?

A. The Company's Abramovitz/Adams/Houston/Robinson panel's direct testimony at page 31 states that the Company is requesting approval of a $20 million increase to be effective January 1, 2023. The Company's calculation shown on Exhibit___(APA/SPA/ADH/MBR-1, Schedule 5 MFF) shows a total MFF revenue deficiency of $20.171 million for 2023. The Abramovitz/Adams/Houston/Robinson panel also stated that the Company would also propose to update the MFF tariff with an annual November 1 compliance filing, if needed, as provided in the current MFF tariff.

Q. IS THE MFF TARIFF REVENUE REQUIREMENT INCREASE THAT THE COMPANY REQUESTED IMPACTED BY THE LEVEL OF THE BASE RATE AND ECCR REVENUE DEFICIENCY PROPOSED BY THE COMPANY?

A. Yes.

Q. IS STAFF'S RECOMMENDATION ON THE AMOUNTS OF BASE RATE AND ECCR REVENUE DEFICIENCY DIFFERENT THAN THE AMOUNTS INCLUDED IN THE COMPANY'S DIRECT CASE?

A. Yes.

Q. ARE THERE ANY OTHER DIFFERENCES BETWEEN THE STAFF AND COMPANY CASES RELEVANT TO THE CALCULATION OF THE MFF TARIFF REVENUE REQUIREMENT?

A. Yes. Staff also shows a different amount of DSM revenue deficiency than was incorporated in Georgia Power's filing, as described above in Section VI of our

testimony. In addition, Staff's recommended weighted average cost of capital is lower than Georgia Power's request. This translates into a lower pre-tax weighted average cost of capital.

Q. HAVE YOU CALCULATED THE MFF REVENUE REQUIREMENT DEFICIENCY TO REFLECT THE IMPACT OF THE DIFFERENCES IN PRE-TAX COST OF CAPITAL AND THE BASE RATE, ECCR AND DSM REVENUE DEFICIENCY AMOUNTS?

A. Yes. On Exhibit__(RS/RT-5), page 3 of 4, we have reproduced the Company's MFF Revenue Requirement deficiency calculations. Exhibit__(RS/RT-5), page 4 of 4, which shows the Staff's calculations. The Staff calculations use the Staff's pre-tax weighted average cost of capital, base rate, ECCR and DSM revenue deficiency amounts. Staff's calculations produce an MFF revenue deficiency of $4.7 million for the test year, and $5.5 million for 2023, as calculated on Exhibit__(RS/RT-5), page 4. Differences between Company and Staff revenue deficiencies for MFF are summarizes on Exhibit__(RS/RT-5), page 2.

Q. DOES STAFF AGREE WITH THE COMPANY'S PROPOSAL THAT THE MFF SHOULD BE UPDATED BY AN ANNUAL NOVEMBER 1 COMPLIANCE FILING, IF NEEDED, AS PROVIDED IN THE CURRENT MFF TARIFF?

A. No. Staff recommends that the filing date for the updated MFF tariffs be on October 1, rather than November 1. The October 1 date is the date being used for other compliance filings (e.g., base rates, ECCR, DSM) to update rates.

VIII. COAL COMBUSTION RESIDUALS ASSET RETIREMENT OBLIGATIONS REVENUE REQUIREMENT

Q. HOW IS THE OBLIGATION FOR CCR COMPLIANCE RECORDED FOR ACCOUNTING PURPOSES AND RECOVERED FROM CUSTOMERS IN RATES?

A. For accounting purposes, the Company's obligation for compliance with CCR regulations is recorded as an Asset Retirement Obligation. A related liability is also recorded to recognize the legal obligation to incur such costs. Historically, costs related to the remediation of ash ponds and landfills that have been used to store coal ash at plants that were still operational would have generally been included in the cost of removal/negative net salvage component of depreciation rates and would have been recovered over the estimated remaining life of the coal-fired generating plants. CCR compliance costs for coal-fired generating plants that have already been retired or are being retired before their previously estimated useful lives are being addressed for cost recovery. Both the Company and Staff have calculated revenue requirements related to the recovery of CCR costs in the current rate case proceeding. On Exhibit __(RS/RT-6) we have replicated the Company's calculated CCR ARO Compliance revenue deficiency amounts for the test year and for each plan year, 2023 through 2025, and also present Staff's calculated revenue deficiency amounts for each period for the CCR ARO Compliance. Staff's adjusted amounts differ from those calculated by the Company primarily because Staff has used witness Gorman's recommended cost of capital.

Q. HOW DOES THE OBLIGATION FOR CCR COMPLIANCE IMPACT RATEPAYERS?

A. The Company's expenditures for CCR compliance have consistently exceed revenues collected from ratepayers under ECCR. This creates unpaid balance that the Company earns a full return on including interest expense, return on equity (profit) and income taxes in addition to the direct cost for remediating coal ash ponds. The Company has projected to spend $320 million, $408 million and $510 million in 2023, 2024 and 2025, respectively, for CCR compliance. The revenues collected from ratepayers are estimated to be $237 million, $308 million and $345 million in 2023, 2024 and 2025, respectively. The unpaid balance is projected to grow to $365 million, $465 million and $630 million as of December 31, 2023, 2024 and 2025, respectively.[10] Georgia Power would collect approximately $26 million, $34 million and $45 million for profit and income taxes on the unpaid balance in 2023, 2024 and 2025, respectively.[11] The profit and income tax amounts are in addition to the interest expense on the portion of the unpaid CCR compliance balance that has been financed with debt.[12]

Q. WAS GEORGIA POWER'S ENVIRONMENTAL COMPLIANCE STRATEGY APPROVED IN THE 2022 INTERATED RESOURCE PLAN (IRP)?

[10] APA-SPA-ADH-MBR-1, Schedule 3 ECCR Supplemental.xlsx

[11] These values were calculated using Georgia Power's proposed ROE and capital structure.

[12] Staff estimates the return on the unpaid balance would be cut in half if coal ash pond remediation costs were securitized. For the portion of the CCR compliance costs for ash ponds at generating plants that have been retired, the unpaid balance is the result of the recovery of costs for units that are no longer providing electric service. A lower return would be more equitable as the Company would be compensated by financing the balance at less cost to ratepayers.

A. Yes. In the 2022 IRP Stipulation approved by the Commission, parties agreed that the Company would seek recovery of CCR costs in its 2022 base rate case. Staff reserved the right to challenge the Company's request for recovery in the 2022 base rate case, including, but not limited to, the amount to be recovered as reasonable and prudent, the period over which costs are recovered and the method by which the costs are recovered.

Q. WHAT CCR ARO COMPLIANCE REVENUE DID THE COMPANY PROPOSE IN THIS CASE?

A. Georgia Power has requested approval of CCR ARO Compliance Revenue Requirement Increases of $60.04 million for the test year, and $64.49 million, $142.51 million and $189.25 million for the years 2023 through 2025, respectively.[13] For each year 2023 through 2025, the Company requested recovery of CCR ARO costs through annual ECCR tariff updates. This is consistent with the methodology approved by the Commission in the 2019 base rate case. If CCR ARO compliance costs are lower than expected, the annual revenue requirement updates for 2024 and 2025 will also be lower.

Q. WERE CONCERNS RAISED IN THE IRP REGARDING GEORGIA POWER'S ASH POND CLOSURE PLANS?

A. Yes. Concerns were raised that Georgia Power's closure plans may not comply with EPA regulations at sites where ash is understood to be in contact with groundwater.

Q. ARE THE COMPANY'S CLOSURE PLANS FINAL?

[13] Exhibit___(APA/SPA/ADH/MBR-1, Schedule 3 ECCR Supplemental) Page 6

A. No. The Company indicated in its IRP that it will continue to refine and optimize its closure plans.[14]

Q. DOES GEORGIA POWER MAINTAIN IT IS IN COMPLINACE WITH CLOSURE RULES, EVEN WITH ASH IN CONTACT WITH GROUNDWATER?

A. In the hearing on Georgia Power's direct testimony, Mr. Womack was asked, "… if the company were to be found not incompliance with CCR rules, wouldn't you agree that it would be unreasonable to get recovery for those expenses through higher rates?" Mr. Womack responded, "I would deny -- your question is interesting, but it's also very speculative. And I -- I don't think it's appropriate for me to comment on it at all -- on that question at this time." He went on to say, "… We … are in compliance with current rules, federal and state."[15]

Q. DOES STAFF HAVE REASON TO BELIEVE THE COMPANY'S CLOSURE PLANS MAY NOT COMPLY WITH U.S. EPA REGULATIONS?

A. Yes. Georgia Power plans to close in place four impoundments where ash has been in contact with groundwater. There are unresolved disputes concerning what constitutes compliance.

Q. HAS THE EPA INDICATED HOW IT VIEWS COMPLIANCE?

[14] Docket No. 44160, Transcript Volume II P. 812, lines 23-25

[15] Docket No. 44280, September 27 Transcript, p. 169, lines 11-23.

A. Yes. The EPA issued a News Release on January 11, 2022 titled, "**EPA Takes Key Steps to Protect Groundwater from Coal Ash Contamination"** in which it restated, through proposed determinations, its:

> …**consistently held position that surface impoundments or landfills cannot be closed with coal ash in contact with groundwater.** Limiting the contact between coal ash and groundwater after closure is critical to minimizing releases of contaminants into the environment and will help ensure communities near these facilities have access to safe water for drinking and recreation.[16] (Emphasis Added).

Q. WAS IT ACKNOWLEDGED IN THE 2022 IRP THAT THE UNITED STATES ENVIRONMENTAL PROTECTION DIVISION MIGHT REQUIRE GEORGIA POWER TO ALTER ITS CLOSURE PLANS FOR CERTAIN ASH PONDS?

A. Yes. The approved stipulation in the 2022 IRP proceeding noted that the Company would continue to provide semi-annual reports to the Commission and provide notice to the Commission within 30 days of any determination by the Environmental Protection Division that would alter the Company's current plan from closing certain ash ponds in place.

Q. IS STAFF MAKING A RECOMMENDATION IN THIS CASE TO ADJUST THE CCR ARO REVENUE REQUEST FOR THE COMPANY'S PROPOSED CLOSURES IN PLACE WHERE ASH HAS BEEN IN CONTACT WITH GROUNDWATER?

A. No. However, this should not be taken to mean Staff believes closure in place with ash in groundwater complies with EPA regulations. Staff will reserve its recommendation on

[16] https://www.epa.gov/newsreleases/search/press_office/headquarters-226129

the prudence of these expenditures until such time as EPA or the courts have determined whether Georgia Power's closure plans comply with EPA regulations.

Q. WILL GEORGIA POWER CONTINUE TO REFINE ITS COST ESTIMATES?

A. Yes. As the closure plans are reviewed and approved by the Georgia Environmental Protection Division, and as closure technologies and alternatives improve, it is likely the cost estimates for closure will need to be updated. The Company is also continuing to explore beneficial use alternatives, which might offset some of the ash pond closure costs. Thus, it is reasonable to adopt Georgia Power's step increase approach for CCR ARO costs.

IX. ORGANIZATION OF STAFF'S REVENUE REQUIREMENT AND ADJUSTMENT SCHEDULES

Q. HOW ARE STAFF'S REVENUE REQUIREMENT AND ADJUSTMENT SCHEDULES ORGANIZED?

A. Staff's revenue requirement and adjustment schedules for the traditional rate case, and each calendar year in the three-year plan are presented in Exhibit__(RS/RT-2). They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, A-2, B, B.1, C, C.1 and D. Exhibit__(RS/RT-2) also contains adjustment Schedules E-1 through E-38.

Q. WHAT DOES EXHIBIT__(RS/RT-2), SCHEDULE A SHOW?

A. Exhibit__(RS/RT-2), Schedule A presents a revenue requirement summary. Georgia Power's calculation of its proposed traditional test year revenue deficiency of $447.521 million is shown in column A, on line 7. Column A, lines 8 and 9, show Georgia Power's proposed revenue deficiency amounts of $105.626 million and $29.650 million for the ECCR and DSM tariffs, respectively. Georgia Power's Application shows a traditional base rate revenue deficiency of approximately $312.245 million after accounting for the ECCR and DSM tariff revenue deficiencies, as shown in column A, line 10. Exhibit__(RS/RT-2), Schedule A, Column B, presents summary information for the Company proposed Alternative Rate Plan, which covers calendar years 2023 through 2025. As shown on Exhibit__(RS/RT-2), Schedule A, Columns A and B, line 11, the Company also has requested an additional revenue increase of $426.415 million to be in effect on January 1, 2023, in arriving at its requested $738.661 million for the

levelization of its calculated 2023 through 2025 revenue requirements, which are shown on lines 11 and 12, respectively. The total January 1, 2023 revenue increase requested by the Company of $738.661 million is shown in Columns A and B, on line 12.

Columns C through F show the revenue requirement calculation that results from our recommendations and the recommendations of other Staff witnesses. Staff's base rate revenue deficiency for the traditional test year, and for each calendar year, 2023 through 2025, are shown on line 7. Staff's adjusted ECCR and DSM revenue deficiencies (excess) are shown on lines 8 and 9, respectively.[17] Line 10 shows Staff's traditional base rate revenue excess or deficiency amounts for the test year and for each plan year. As noted elsewhere, Staff is not proposing a levelization of 2023–2025 results. Staff total recommended base rate revenue excess or deficiency amounts for the test year and for each plan year are shown on line 12.

Q. WHAT IS SHOWN ON SCHEDULE A-1 OF EXHIBIT__(RS/RT-2)?

A. Schedule A-1, page 1, shows the derivation of the gross revenue conversion factor ("GRCF") for the test year ending July 31, 2023. This factor is used on Schedule A, line 6, to convert the net operating income deficiency or sufficiency into an equivalent revenue requirement amount. As shown on Exhibit__(RS/RT-2), Schedule A-1, page 1, column B, we have used a GRCF of 1.340378 to convert the earnings sufficiency for the 2023 rate year into a revenue deficiency amount. This GRCF is the equivalent of what

[17] As noted in Section VI, the DSM revenue requirements are subject to change.

the Company refers to as an Income Expansion Factor. The GRCF reflects the use of a 21% federal income tax rate and a 5.75% state income tax rate.

As shown on Schedule A-1, page 1 of 2, in column C, Staff's GRCF of 1.340378 or 74.60582% is slightly different than the Company's proposed GRCF because Staff has adjusted the uncollectibles factor.[18] Staff's adjustment to the uncollectibles factor is shown on lines 4 through 8 of Schedule A-1, page 1 of 2, in column C. Staff's proposed GRCF for test year differs slightly from the Company's proposed Income Expansion Factors because of Staff's adjustment for uncollectibles.

Schedule A-1, page 2, shows the derivation of the GRCF used for each plan year. The GRCFs used by Staff for each period are the same as the Company's proposed Income Expansion Factors for each period.

Q. WHAT IS SHOWN ON SCHEDULE A-2?

A. Schedule A-2 consists of 4 pages and shows a detailed reconciliation of the Company's requested and Staff's adjusted revenue requirements. Page 1 shows the reconciliation for the test year ending July 31, 2023. Pages 2-4 show the reconciliation for calendar years 2023, 2024 and 2025, respectively.

Q. PLEASE BRIEFLY EXPLAIN SCHEDULES B AND C OF STAFF EXHIBIT__(RS/RT-2).

[18] The adjustment to test year uncollectibles is discussed in the Direct Testimony of Staff witness Dante Mugrace.

A. The adjustments presented on Schedule A that impact rate base are shown on Schedule B. Schedule B.1 summarizes the Staff's recommended rate base adjustments. Exhibit__ (RS/RT-2) contains a Schedule B and B.1 for the test year ending July 31, 2023 as well as for each plan year, 2023, 2024 and 2025.

Schedules C presents adjusted net operating income. Schedule C.1 summarizes Staff's recommended adjustment to revenue and expenses applicable to the ratemaking analysis. Schedule C.1 also presents the impact on income tax expense resulting from each of Staff's recommended adjustments to pre-tax operating income. Exhibit__(RS/RT-2) contains a Schedule C and C.1 for the test year ending July 31, 2023 and for each calendar year (2023, 2024 and 2025) in the Company's proposed alternative rate plan.

Q. WHAT IS SHOWN ON SCHEDULE D?

A. Schedule D presents the capital structure and cost rates that we used to calculate Staff's recommended revenue requirement in this case. The Company's proposed cost of capital is shown for comparative purposes. The return on common equity of 9.45 percent on Schedule D is based on the recommendations of Staff witness Michael Gorman. Staff's recommended capital structure and the cost rates for long-term debt are sponsored by Staff witnesses Gorman. Schedule D has four pages. Page 1 shows the cost of capital for the test year ending July 31, 2023. Pages 2-4 show the cost of capital for each calendar year, 2023 through 2025, that is included in the Company's proposed alternative rate plan.

Q. HOW ARE STAFF'S ADJUSTMENTS TO RATE BASE AND NET OPERATING INCOME PRESENTED?

A. Staff's adjustments to rate base and net operating income for the test year ending July 31, 2023 and for each plan year (2023, 2024 and 2025) are summarized on Exhibit__(RS/RT-2), Schedules B.1 and C.1, respectively, as noted above. Each Staff adjustment is also shown on Exhibit__(RS/RT-2) on Schedules E-1 through E-38, and is discussed in Section X of our testimony.

X. STAFF ADJUSTMENTS

Overall Rate of Return

Q. HOW HAVE YOU REFLECTED THE OVERALL RATE OF RETURN RECOMMENDED BY STAFF WITNESSES MICHAEL GORMAN?

A. On Staff Exhibit__(RS/RT-2), Schedule D, we have replicated Georgia Power's requested capital structure, capital cost rates, and resulting overall rate of return (from the Company's original filing before adjustments). The primary change to the Company's proposed overall rate of return determination is Mr. Gorman's recommended return on equity rate of 9.45% as opposed to Georgia Power's proposed return on equity of 11.0%, and the capital structure recommended by Mr. Gorman. Staff's recommended overall cost of capital for the test year is 6.84%, compared with Georgia Power's request of 7.70%. This is shown on Staff Exhibit__(RS/RT-2), Schedule D, page 1 of 4, column D, line 6. Staff's recommended overall cost of capital for the 2023, 2024 and 2025 plan years is summarized on Schedule D, pages 2 through 4 of 4, respectively.

E-1, Company Supplemental Filing - Rate Base Adjustments

Q. GEORGIA POWER'S INITIAL RATE CASE FILING WAS ON JUNE 24, 2022. DID THE COMPANY SUPPLEMENTTHAT INITIAL FILING?

A. Yes. On August 22, 2022, the Company filed a supplement to its initial rate case filing. Specifically, the supplemental filing reflects the revenue requirement impacts from various items included in the Final Order that was approved by the Commission in Georgia Power's 2022 Integrated Resource Plan ("2022 IRP") and DSM Certification proceedings in Docket Nos. 44160 and 44161.

Q. WHAT SPECIFIC REVENUE REQUIREMENT IMPACTS ARE REFLECTED IN GEORGIA POWER'S SUPPLEMENTAL FILING?

A. The Company's transmittal letter lists the following revenue requirement impacts in its supplemental filing:

- Defer Retirement Decision on Plant Bowen Units 1&2
- Update Plant Scherer ELG Capital Cost
- Update Capacity RFP PPA Additional Sum
- Update DG PPA Additional Sum
- Remove Wholesale to Retail Capacity Offer of 88 MWs related to Plant Yates Units 6&7 and Blocks 5&6
- Remove North Highlands Hydro Modernization Project
- Include DER Local Reliability and Constraints Pilot Projects
- Remove Tall Wind Research and Development Project
- Update DSM costs and additional sum, along with revenue impacts from the revised energy savings targets

Q. DID THE COMPANY FILE A SCHEDULE WITH ITS SUPPLEMENTAL FILING WHICH REFLECTS THE REVENUE REQUIREMENTS LISTED ABOVE?

A. Yes. The Company filed a schedule in Excel, which summarizes the incremental revenue requirement impacts that it made to its initial proposed revenue requirement as shown on Company Exhibit__(APA/SPA/ADH/MBR-1 Schedule 1 Total Company). Page 5 of the Company's schedule reflects the adjustments which impact the Company's retail rate

base. Specifically, page 5 of the Company's schedule reflects various adjustments to increase and/or reduce electric plant in service, accumulated depreciation, accumulated deferred income taxes ("ADIT") as well as other rate base items including (1) fuel and materials and supplies inventory, (2) minimum bank balances and prepayments, (3) prepaid pension asset, (4) operating reserves, and (5) Bowen and Scherer depreciation deferral. These adjustments increase retail rate base for the forecasted test year and the plan years by $9.524 million (test year), $16.781 million (2023), $19.352 million (2024) and $12.022 million (2025).

Q. PLEASE EXPLAIN THE RATE BASE ADJUSTMENTS SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDULE E-1.

A. Those adjustments reflect the retail rate base adjustments that are shown on page 5 of the Company's supplemental filing schedule. As shown on Staff Exhibit__(RS/RT-2), Schedule E-1, our adjustments increase the Company's retail rate base by $9.524 million, $16.781 million, $19.352 million and $12.022 million for the forecasted test year and plan years 2023, 2024 and 2025, respectively.

Q. DID YOU ALSO MAKE ADJUSTMENTS RELATED TO THE COMPANY'S SUPPLEMENTAL FILING TO OPERATING INCOME?

A. Yes. We also made adjustments related to the Company's operating income, which are reflected on Staff Exhibit__(RS/RT-2) and discussed in the next section of our testimony.

E-2, Company Supplemental Filing - Operating Income Adjustments

Q. PLEASE EXPLAIN THE ADJUSTMENTS SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDULE E-2.

A. These adjustments to operating income are made pursuant to the Company's supplemental filing. Specifically, page 6 of the Company's supplemental filing schedule reflects various adjustments to (1) operating revenues, (2) O&M expense, (3) depreciation and amortization expense, (4) taxes other than income taxes and, (5) income taxes. The total of these supplemental adjustments reduces retail operating income for the forecasted test year and the plan years by $8.401 million (test year), $19.680 million (2023), $30.384 million (2024) and $29.908 million (2025).

E-3, Forecasted Revenues

Q. PLEASE EXPLAIN THE ADJUSTMENT TO FORECASTED OPERATING REVENUES.

A. The amounts shown on Exhibit__(RS/RT-2), Schedule E-3 were supplied by Staff witnesses Steven Baron and Leah Wellborn, who are recommending forecasted operating revenues at current rates that differ from those proposed by Georgia Power. As shown on Staff Exhibit__(RS/RT-2), Schedule E-3, incorporating Mr. Baron's and Ms. Wellborn's recommendations to forecasted operating revenues at current rates increases the Company's retail electric operating revenue by $5.991 million for the test year, $5.697 million for 2023, $4.867 million for 2024 and $7.752 million for 2025.

E-4, Stock-Based Compensation

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR STOCK-BASED COMPENSATION.

A. This adjustment is shown on Exhibit__(RS/RT-2), Schedule E-4, and decreases pre-tax operating expenses by $29.172 million for the test year, $29.063 million for 2023, $26.933 million for 2024 and $28.230 million for 2025. This adjustment explained in additional detail in Section XII of our testimony, which addresses incentive compensation.

E-5, Payroll Tax Expense

Q. PLEASE EXPLAIN THE ADJUSTMENT TO PAYROLL TAX EXPENSE.

A. Staff's adjustment to the Company's payroll tax expense is made in conjunction with the adjustments that are being made to remove stock-based compensation. Based upon those recommended adjustments, as shown on Exhibit No.__(RS/RT-2), Schedule E-5, in column A, Georgia Power's proposed traditional test year payroll tax expense is reduced by $2.232 million.

For the years associated with the Company's proposed Alternative Rate Plan, payroll tax expense is reduced by $2.223 million, $2.061 million and $2.159 million in 2023, 2024 and 2025, respectively, as shown on Exhibit No.__(RS/RT-2), Schedule E-5, in columns B through D, respectively.

E-6, Energy Direct Premium Packages

Q. PLEASE EXPLAIN THE COMPANY'S ENERGY DIRECT PREMIUM PROGRAM.

A. Georgia Power commercial customers have electronic access to their energy use data through Energy Direct. Energy Direct is managed by a Southern Company Services product manager and the Southern Company Technology Organization in conjunction with operating company product managers as well as key account managers at each electric affiliate.

Q. DOES THE COMPANY OFFER DIFFERENT PACKAGES ASSOCIATED WITH THE ENERGY DIRECT PROGRAM?

A. Yes. The Company offers an Energy Direct Standard Package as well as enhanced Energy Direct usage packages, including Standard Plus, Premium, Premium Plus and Premium RT. Georgia Power provides all commercial customers access to the Energy Direct Standard Package at no charge. The enhanced Energy Direct packages are provided to commercial customers for a monthly subscription fee.[19]

Q. HOW DOES GEORGIA POWER ACCOUNT FOR REVENUES AND EXPENSES ASSOCIATED WITH THE ENERGY DIRECT STANDARD AND PREMIUM PACKAGES?

A. With regard to the Energy Direct Standard Package, according to the response to STF-LA-3-1, since the Standard Package is available at no charge, there are no revenues

[19] See the response to STF-LA-3-1.

associated with the Standard Package. However, expenses associated with the Standard Package are recorded in FERC account 908 and thus, are being included in the Company's retail cost of service.[20]

As it relates to the Premium Packages, according to the response to STF-LA-3-3, the revenues associated with the Premium Packages are recorded below-the-line in FERC account 415. Likewise, the expenses associated with the Premium Packages are also recorded below-the-line in FERC account 416.

Q. HAS THE COMPANY EXPLAINED WHY THE ENERGY DIRECT PREMIUM PACKAGE REVENUE AND EXPENSES ARE UNREGULATED (I.E., RECORDED BELOW-THE-LINE) WHEN THE STANDARD PACKAGE EXPENSES ARE REGULATED (I.E., RECORDED ABOVE-THE-LINE)?

A. Yes. In response to an informal Staff inquiry regarding this issue, the Company stated:

> Energy Direct provides a management tool for Commercial and Industrial customers. The standard package is available at no cost and is a Regulated Above the Line (ATL) service. The premium packages provide customers with additional data and have a monthly cost to customers. All revenue for EnergyDirect is unregulated below-the-line (BTL) because it is associated with premium packages.
>
> When EnergyDirect was launched, the Company allocated expenses based on the initial development costs incurred to stand up the EnergyDirect Program. At that time, it was determined that 70% of the Program's capital and O&M costs would have been incurred to develop the Regulated ATL Standard Package and 30% for the Unregulated BTL Premium Packages. This breakdown for program expenses continues. However, expenses that are incurred specifically to support the Unregulated offerings are charged 100% Unregulated BTL.

[20] See the response to STF-LA-3-2.

Q. DO YOU AGREE WITH THE COMPANY'S ACCOUNTING TREATMENT WHEREBY THE REVENUES AND EXPENSES ASSOCIATED WITH THE ENERGY DIRECT PREMIUM PACKAGES ARE UNREGULATED (I.E., RECORDED BELOW-THE-LINE)?

A. No. We do not agree with the Company's accounting treatment whereby the revenues and expenses associated with the energy direct premium packages are unregulated (i.e., below-the-line). Specifically, we do not see a valid distinction as to why the expenses associated with the Energy Direct Standard Package should be recorded above-the-line while the revenues and expenses associated with the Premium Packages should be recorded below-the-line. This treatment would appear to allow the Company to retain the pre-tax profits being earned on the Premium Packages.

Q. WHAT IS STAFF'S RECOMMENDATION WITH REGARD TO THE RATEMAKING TREATMENT OF THE ENERGY DIRECT PREMIUM PACKAGES REVENUE AND EXPENSES?

A. Staff recommends an adjustment to include the projected revenues and expenses associated with the Energy Direct Premium Packages in Georgia Power's net operating income for ratemaking purposes in the forecasted test year and in each of the rate plan years 2023-2025.

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT.

A. Data requests STF-LA-3-3 and STF-LA-3-4 requested that the Company provide the revenues and expenses associated with the Energy Direct Premium Packages for the

forecasted test year and each rate plan year 2023 through 2025. Using the information provided in those responses, we calculated an adjustment whereby the net revenue associated with the Energy Direct Premium Packages is included in Georgia Power's net operating income.

Specifically, as shown on Exhibit__(RS/RT-2), Schedule E-6, our recommended adjustment increases pre-tax operating income by $1.165 million for the forecasted test year, $1.176 million for 2023, $1.209 million for 2024 and $1.240 million for 2025.

E-7, Miscellaneous Items / Executive Financial Planning

Q. PLEASE EXPLAIN THE EXECUTIVE FINANCIAL PLANNING ADJUSTMENT SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDUE E-7.

A. In its response to STF-LA-2-56, the Company confirms that the proposed test year operating expenses include $470,015 associated with its executive financial planning program. This amount includes Georgia Power direct charges of $195,734 as well as charges allocated to Georgia Power by SCS and SNOC of $191,000 and $83,281, respectively. In addition, each plan year's operating expenses reflects similar executive financial planning costs in the categories noted above, including $468,984 in 2023, $469,609 in 2024 and $469,523 in 2025. This program provides personal financial planning, estate planning, investment advice and tax planning and preparation to Georgia Power's Chief Executive Officer, Chief Operating Officer, Vice-Presidents and Directors. We do not believe that the captive ratepayers of Georgia Power should pay for the charges associated with these types of top executive perks. Rather, we believe that the Company's stockholders should be made responsible for these costs. Our recommended

removal of these executive financial planning program costs from the forecasted test year and each plan year is reflected on Staff Exhibit__(RS/RT-2), Schedule E-7. A similar adjustment was recommended by Staff in prior Georgia Power rate cases.

E-8, Interest Synchronization Adjustment

Q. PLEASE DESCRIBE GEORGIA POWER'S PROPOSED INTEREST SYNCHRONIZATION ADJUSTMENT SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDULE E-8.

A. The Company is proposing that interest expenses to be used as a deduction in the calculation of the test year pro forma adjusted income taxes be based on the interest expenses that are implicit in its proposed overall rate of return. These pro forma interest expenses (referred to as the so-called "synchronized" interest expenses) are determined by multiplying the weighted cost of debt component of the overall rate of return times the rate base used in this case.

Q. HAVE YOU DETERMINED THE STAFF-RECOMMENDED TRADITIONAL TEST YEAR SYNCHRONIZED INTEREST EXPENSES IN A SIMILAR MANNER?

A. Yes. The Staff-recommended traditional test year synchronized interest expense amount, calculated in the same manner, is shown in the third column of Staff Exhibit__(RS/RT-2), Schedule E-8, page 1. Plan year synchronized interest adjustment amounts are shown on pages 2-4 of Schedule E-8.

Q. WHY IS THE STAFF'S RECOMMENDED SYNCHRONIZED INTEREST AMOUNT DIFFERENT FROM GEORGIA POWER'S PROPOSED SYNCHRONIZED INTEREST AMOUNT?

A. This disparity is due to the differences in the rate base levels used in Georgia Power's and Staff's respective recommendations and to the difference in the capital structure between Staff and the Company. These differences result in different synchronized interest expense amounts.

Q. HOW DOES THIS DIFFERENCE IN THE TWO SYNCHRONIZED INTEREST EXPENSE LEVELS IMPACT GEORGIA POWER'S PROPOSED TRADITIONAL TEST YEAR AFTER-TAX RETAIL OPERATING INCOME?

A. As shown on line 6 of Staff Exhibit__(RS/RT-2), Schedule E-8, page 1, adoption of Staff's recommended synchronized interest amount increases the Company's traditional test year retail income tax expense by $598,000 and decreases after-tax operating income by that same amount, i.e., by $598,000.

The interest synchronization adjustments for each plan year are shown on Schedule E-8, pages 2-4, respectively.

E-9, O&M Scrap Sales Proceeds

Q. WHAT IS GEORGIA POWER'S PROCEDURE FOR RECORDING OBSOLETE AND/OR SCRAP MATERIAL SALES PROCEEDS?

A. According to the response to STF-LA-2-25, the Company's for recording obsolete and/or scrap material sales proceeds is to credit salvage or O&M expense as appropriate for actual sales proceeds.

Q. DID GEORGIA POWER INCLUDE ANY AMOUNTS FOR OBSOLETE AND SCRAP MATERIAL SALES PROCEEDS IN THE FORECASTED TEST YEAR AND IN EACH OF THE RATE PLAN YEARS COST OF SERVICE?

A. No, it did not.

Q. DID GEORGIA POWER EXPLAIN WHY IT DID NOT INCLUDE ANY AMOUNTS FOR OBSOLETE AND SCRAP MATERIAL SALES PROCEEDS IN THE FORECASTED TEST YEAR AND EACH OF THE RATE PLAN YEARS COST OF SERVICE?

A. In its response to STF-LA-2-25, the Company stated that due to the uncertainty of obsolete and scrap material sales, no related proceeds are reflected in the forecasted test year or in each rate plan year 2023, 2024 and 2025.

Q. DID GEORGIA POWER RECORD OBSOLETE AND/OR SCRAP MATERIAL SALES PROCEEDS IN EACH YEAR 2016 THROUGH 2021 AND IN 2022 TO DATE?

A. Yes. In its response to STF-LA-2-25, the Company provided the O&M scrap sales proceeds for each year 2016 through 2021 and 2022 through May in the table below:

Year	Amount
2016	$ 1,465,670
2017	$ 1,149,340
2018	$ 713,035
2019	$ 737,674
2020	$ 1,544,267
2021	$ 1,369,796
2022 (through May)	$ 876,935
Source: STF-LA-2-25	

As shown in the above table, Georgia Power recorded O&M scrap sales proceeds in each year 2016 through 2021 and in 2022 through May.

Q. BASED ON GEORGIA POWER RECORDING O&M SCRAP SALES PROCEEDS IN EACH OF THE LAST SIX CALENDAR YEARS AND IN 2022 THROUGH MAY, IS IT REASONABLE TO CONCLUDE THAT THE COMPANY WILL RECORD O&M SCRAP SALES PROCEEDS IN THE FORECASTED TEST YEAR AND RATE PLAN YEARS?

A. Yes.

Q. HAS THE COMPANY PREVIOUSLY AGREED THAT A REPRESENTATIVE LEVEL OF O&M SCRAP SALES PROCEEDS SHOULD BE REFLECTED IN THE SETTING OF RATES?

A. Yes. In the Company's errata filing dated September 25, 2007 in its 2007 rate case in Docket No. 25060, the Company agreed that a representative level of O&M scrap sales proceeds should be reflected in the setting of rates.

Q. DID THE COMMISSION REACH A SIMILAR CONCLUSION IN A MORE RECENT GEORGIA POWER RATE CASE?

A. Yes. In its Final Order in which the Commission approved the Stipulation in Georgia Power's 2010 rate case in Docket No. 31958, the Commission stated that it found Staff's adjustment to reflect a representative level of scrap sales proceeds to be reasonable. Specifically, in Section 6 on page 8 of its Final Order, the Commission stated:

> Lines 12-23 of the "Georgia Power Company Revenue Deficiency Table" consist of "Other Rate Base and Operating Income Adjustments." The Stipulation incorporates the Advocacy Staff's recommended adjustments for M&S Inventory Write-Off, 2010 ECCR Cost Deferral, Wholesale Capacity Sales Adjustment, **Proceeds from Scrap Sales**, Property Tax and Uncertain Tax Positions. The Commission finds that the resolution of these line items to be reasonable.
>
> (Emphasis supplied)

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR O&M SCRAP SALES PROCEEDS.

A. In lieu of the Company providing forecasted amounts for O&M scrap sales proceeds for the test year and each of the rate plan years, Staff used the amounts noted above from the response to STF-LA-2-25 for the O&M scrap sales the Company recorded during the period January 2016 through May 2022. Specifically, Staff summed the scrap sales and divided the total by 77 months (six years from 2016-2021 plus five months of 2022) to derive a monthly amount of O&M scrap sales proceeds. This amount was then multiplied by 12 months to derive an annual amount of $1.224 million. Staff reflected this amount for the forecasted test year and each of the rate plan years.

As shown on Exhibit__(RS/RT-2), Schedule E-9, Staff's recommended adjustment reduces retail O&M expense by $1.216 million for the test year and each rate plan year 2023, 2024 and 2025.

E-10, Cash Working Capital

Q. WHAT HAS THE COMPANY REQUESTED FOR CASH WORKING CAPITAL?

A. For the future test year ending July 31, 2023, the Company has reflected negative cash working capital of $54.889 million, based on an updated lead-lag study that it conducted for purposes of this case.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR CASH WORKING CAPITAL.

A. As shown on Exhibit__(RS/RT-2), Schedule E-10, the only adjustments we are recommending to the Company's cash working capital in the current rate case result from adjustments that are being by Staff for certain cash operating expenses. As the result of having adjusted various cash operating expenses, the amount of cash working capital computed in Staff's case differs from the amounts that were presented in the Company's filing.

E-11, Wireless Co-Location Revenues

Q. HAS GEORGIA POWER MADE ADJUSTMENTS TO REVENUE IN ITS ANNUAL SURVEILLANCE REPORTS RELATED TO ITS CO-LOCATION WIRELESS EQUIPMENT PROGRAM?

A. Yes. Georgia Power has made adjustments to revenue in its Annual Surveillance Reports related to its Co-Location Wireless Equipment program. Specifically, the Company's adjustment in its ASR's (1) removes 50 percent of revenues net of program expenses associated with its transmission tower assets per the Commission's Order in Docket No. 25322, and (2) removes 40 percent of revenues net of expenses associated with small cell installations or macro cell development for retail facilities such as telecom towers and/or

land leases on the Company's regulated assets per the Commission's Order in Docket No. 36989.

Q. WHEN WAS THE CO-LOCATION WIRELESS EQUIPMENT PROGRAM MOST RECENTLY ADDRESSED?

A. The Co-Location Wireless Equipment program was most recently addressed in the Company's 2019 ASR. Specifically, as it relates to this issue in the 2019 ASR, the Commission stated:

> In 2019, the Company communicated to Staff a proposal to expand the Commission-approved colocation program to cover additional classes of facilities like distribution lighting poles and certain land that were not discussed in the Commission's Order in Docket No. 25322. This expansion related primarily to the ongoing development of 4G and 5G networks. For reporting purposes, the Company treated the colocation revenue as though it was from the Colocation Program approved in Docket No. 25322. Staff did not agree with this treatment and took the position that the Colocation Order applied only to Transmission Towers. After several discussions, the Staff and Company reached an agreement that will temporarily resolve this issue.
>
> As documented in Staff's Summary Report, the Company agreed to forego its share of telecommunication colocation revenue reported in the 2019 ASR. For purposes of the 2019 ASR, the adjustment reflected in Section 6, Workpaper 20 and Section 3, Income, which reflects sharing with the Company, will be reversed and the amount will be used to reduce regulatory assets in the priority set out in Paragraph 12 of the Stipulation in Docket 42516. In years 2020 – 2022 the Company will continue to apply 50/50 sharing for collocation revenue resulting from the collocation of telecommunications equipment on transmission towers.
>
> For years 2020 – 2022 the Company agreed any revenue reported from the collocation program associated with small cell installations on the Company's regulated assets will be allocated for ASR Reporting purposes 60% to ratepayers and 40% retained by the Company. The 60/40 sharing allocation will also be used for macro cell development on retail facilities such as telecom towers and land leases.
>
> Staff and the Company agreed that the Colocation Program and sharing percentages may be reevaluated in the Company's next base rate case. For the purpose of settlement, the Company and Staff agree to make a good faith

effort to resolve any dispute around the sharing of colocation revenues prior to August 1, 2021, in order to allow for any resolution, should one be reached, to be included in the Company's next base rate case.

Q. DID GEORGIA POWER INCLUDE AMOUNTS RELATED TO THE CO-LOCATION WIRELESS EQUIPMENT PROGRAM IN THE FORECASTED TEST YEAR AND RATE PLAN YEARS?

A. Yes. In its Trade Secret response to STF-LA-12-1, the Company provided the following projected amounts for co-location revenue recorded in FERC account 456[21]: [redacted]

Q. ARE THE AMOUNTS SHOWN ABOVE SUBJECT TO THE GEORGIA POWER'S PROPOSAL TO CONTINUE THE 60/40 SHARING ALLOCATION?

A. Yes. Through informal communications with the Company, Georgia Power stated that it projects all wireless co-location revenues for the test period and rate years 2023-2025 to come from retail assets other than transmission towers, thus the Company applied the 60/40 sharing percentage. In addition, the Company stated that it applies the sharing percentage to the revenues net of program expenses so that the so-location revenues included in the retail cost of service are net of such expenses. However, this 60/40

[21] [redacted]

sharing allocation was temporary under the 2019 ASR Order and the Company has not explained why it is appropriate as on a going forward basis.[22]

Q. IS STAFF MAKING A RECOMMENDATION RELATED TO THE CO-LOCATION WIRELESS EQUIPMENT PROGRAM IN THE CURRENT CASE PURSUANT TO THE COMMISSION'S RECOMMENDATION IN THE 2019 ASR?

A. Yes. Staff recommends that the revenue sharing allocation related to the Co-Location Wireless Equipment Program be updated whereby 80% of such revenues be allocated to ratepayers with the Company retaining the remaining 20% of co-location net revenues. Georgia Power is already earning a return on the regulated assets in rate base. Georgia Power's return on these assets, and the associated expenses (financing, depreciation, taxes, O&M) are paid for by ratepayers. When these rate based assets are deployed to generate additional revenue, the revenue should be used to benefit ratepayers.

As shown on Exhibit__(RS/RT-2), Schedule E-11, Staff applied an 80/20 sharing percentage to the net co-location revenues, which results in an adjustment to increase pre-tax operating income by $404,000 for the test year, $433,000 for 2023, $520,000 for 2024 and $626,000 for 2025.

[22] For example, when the Commission approved the sharing of transmission co-location revenues, one of the considerations appears to have been giving the Company an incentive to allow co-locations when it was not required to do so that there would be revenue to share. The Company has not explained how such any incentive is needed here.

E-12, Depreciation Expense and Accumulated Depreciation - New Depreciation Rates

Q. DID STAFF CALCULATE AN ADJUSTMENT TO THE COMPANY'S PROPOSED DEPRECIATION EXPENSE FOR THE TEST YEAR AND EACH RATE PLAN YEAR TO REFLECT THE NEW DEPRECIATION RATES THAT STAFF IS RECOMMENDING?

A. The amounts shown on Exhibit__(RS/RT-2), Schedule E-12, page 1, are adjustments to the Company's proposed depreciation expense amounts in the test year and in each plan year which were calculated based on the depreciation rates supplied by Staff witness Lance Kaufman. Mr. Kaufman is recommending new depreciation rates that differ from those proposed by Georgia Power in the Company's depreciation study for production plant, transmission plant, distribution plant and general plant.

Q. WHAT IS THE IMPACT OF USING THE NEW DEPRECIATION RATES THAT ARE BEING RECOMMENDED BY STAFF WITNESS KAUFMAN?

A. As shown on Exhibit__(RS/RT-2), Schedule E-12, page 1, line 19, Georgia Power's proposed depreciation expense is reduced by $31.434 million for the test year, $54.117 million for 2023, $57.236 million for 2024 and $59.513 million for 2025. Details are shown on Exhibit__(RS/RT-2), Schedule E-12, pages 3-18.

Q. DID GEORGIA POWER'S DEPRECIATION STUDY INCLUDE DEPRECIATION RATES FOR INTANGIBLE PLANT?

A. No. Through informal communications in an email dated October 17, 2022, Georgia Power advised that intangible plant was excluded from its depreciation rate study as it is

not subject to a depreciation rate. Rather, the Company stated that software and other intangible assets are amortized over a five-year period.

Q. ARE THERE CORRESPONDING ADJUSTMENTS TO ACCUMULATED DEPRECIATION?

A. Yes. There are corresponding adjustments to accumulated depreciation related to production plant, transmission plant, distribution plant and general plant. Specifically, as shown on Exhibit__(RS/RT-2), Schedule E-12, page 1, line 46, Georgia Power's proposed depreciation expense has been reduced, and accumulated depreciation has been correspondingly reduced on a cumulative basis reflecting the average rate base approach (thus increasing rate base) by $15.741 million for the test year, $27.206 million for 2023, $83.023 million for 2024 and $141.383 million for 2025.

E-13, Electric Vehicles Make Ready Program

Q. HAS GEORGIA POWER INCLUDED COSTS RELATED TO ELECTRIC TRANSPORTATION ACTIVITIES IN ITS FILING?

A. Yes. As stated by Mr. Womack in his direct testimony:

> Over the next three years, we will increase our investments in community electric vehicle ("EV") charging facilities and necessary electric transportation infrastructure upgrades to support customer EV charging. In addition to these capital infrastructure upgrades, our rate request includes expenses for administrative costs, infrastructure maintenance, and various rebates for homebuilders and residential and commercial customers to accommodate growth in EV charging across the state.[23]

[23] Direct Testimony of Christopher C. Womack, 10:9-14

Q. HOW MUCH HAS THE COMPANY REQUESTED FOR ELECTRIC TRANSPORTATION ACTIVITIES IN ITS FILING?

A. The Company requested $30 million annually for EV capital infrastructure spending in each plan year 2023 through 2025, as detailed in the STF-PIA-3-5 Attachment which is replicated below:

GEORGIA POWER COMPANY
ELECTRIC VEHICLE INFRASTRUCTURE

	Actual		Budget			
	2020	2021	2022	2023	2024	2025
Capital Infrastructure Upgrades	$ 2,001,778	$ 5,986,332	$ 14,000,000	$ 30,000,000	$ 30,000,000	$ 30,000,000
Administrative Costs	$ 1,453,275	$ 1,069,422	$ 1,084,037	$ 1,920,826	$ 2,242,116	$ 2,565,869
Infrastructure Maintenance	-	-	-	42,872	68,392	68,928
Rebates	473,377	507,526	514,520	2,815,000	2,879,745	2,945,979

Q. WHAT PORTION OF THE $30 MILLION OF ANNUAL EV INFRASTRUCTURE SPENDING REPRESENTS SPENDING FOR THE COMPANY'S PROPOSED ELECTRIC TRANSPORTATION "MAKE READY" PROGRAM?

A. The Company has requested $27 million per year for 2023 through 2025, for a proposed capital budget of $81 million for the rate plan.[24] The proposed capital budget of $81 million in total for the Make Ready program for years 2023 through 2025 includes projects in the following categories:[25]

[24] See the response to STF-LA-6-19.

[25] Ibid

Description	Amount (in Millions)
Waitlisted	$5.90
Pipeline	$20.60
Anticipated New	$54.50
Total	$81.00

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING ELECTRIC TRANSPORTATION MAKE READY?

A. The Make Ready program proposed by Georgia Power Company in this docket should be denied and the associated costs be removed for ratemaking purposes. Investments needed to provide an unregulated service to private groups should be paid for by the business or organization wanting to provide that unregulated service. This is true whether or not the unregulated charging service is private or available to the public. As with investments associated with regulated public utilities, the costs should be recovered from cost-causers. The general body of ratepayers should not be subjected to paying for private assets that primarily benefit Make Ready participants. The program, if continued for the next decade, will increase the revenue requirement by close to half a billion dollars.

Q. WHY IS THE MAKE READY PROGRAM NOT IN THE PUBLIC INTEREST?

A. The Make Ready program obligates captive electric service customers to subsidize the provision an unregulated service, electric vehicle charging. The vast majority of retail electric customers do not own electric vehicles and will not own EVs this decade. Additionally, Make Ready equipment is only needed in order to provide unregulated charging services to a small set of Georgia Power's customers. The equipment is not used and useful in providing regulated retail electric service to Georgia Power's customers. As noted in the response to STF-HR-1-2, "To date, nearly all of the total Make Ready

program spend (over 99%) is for the funding of equipment on the customer side of the meter." Make Ready results in co-ownership of unregulated EV charging stations by the monopoly utility. The monopoly utility is allowed to profit now, not only on assets used and useful in the provision of retail electric service, but also on unregulated assets fully funded by customers who do not have a choice of providers.

Q. WHAT MAKE READY SPENDING WAS APPROVED FOR GEORGIA POWER IN THE 2019 RATE CASE AND WHAT WAS APPROVED?

A. Georgia Power received approval of Make Ready spending in the 2019 Rate Case of $6 million per year. The issue was not litigated, and interveners did not have the opportunity to submit positions into the record. The $6 million per year for Make Ready was added to a settlement agreement reached between certain interveners. Item 30 from the 2019 Rate Case Settlement, which was ultimately approved by the Commission, stated:

> 30. The funds for electric vehicle infrastructure will be allowed as proposed by the Company with an additional $6 million per year to be invested in support of wire and transformer upgrades for customer sited charging stations.

Q. WHAT SPENDING WAS AUTHORIZED BY THE APPROVED SETTLEMENT?

A. The annual budget was specifically authorized to support "wire and transformer upgrades". The Company's implementation of the program, however, has exceeded the scope of uses specified in the stipulation agreement. Rather than limit the program to wire and transformer upgrades, which would reasonably be expected to be on the Company's side of the meter, Georgia Power spent 99% of the authorized funds on equipment on the customer's side of the meter as noted above.

Q. DO GEORGIA POWER RATEPAYERS HAVE THE ABILITY TO USE THE CHARGERS AT THE MAKE READY LOCATIONS?

A. The Company did not provide a response to Staff's informal question asking if the public may charge at the Make Ready locations. Staff's understanding, based on conversations with Company personnel, is that there is no obligation for chargers located at Make Ready sites to be made available to the public. Further, Staff understands that Georgia Power does not have a list of which Make Ready charging locations, if any, are open to the public. Thus, with limited exceptions, ratepayers responsible for paying the cost of Make Ready assets, over at least the next decade, will not be able use the charging stations. It appears the vast majority of the charging stations will be private, and not open to the ratepayers who would pay for the supporting assets.

Q. DOES THE COMPANY EARN A PROFIT ON MAKE READY SPENDING?

A. Yes. Make Ready equipment, which is used to provide unregulated charging service that has been installed to date, is included in the regulated rate base. As a result, the Company earns a return on the equity portion of the investment.

Q. DO RATEPAYERS PAY FINANCING CHARGES ON DEBT RAISED TO FUND MAKE READY INFRASTRUCTURE?

A. Yes.

Q. DO RATEPAYERS ALSO PAY TAXES ON THE REVENUE COLLECTED TO FUND MAKE READY INFRASTRUCTURE?

A. Yes.

Q. DO GEORGIA POWER RATEPAYERS BENEFIT FROM THE PROGRAM?

A. Other than car dealerships[26] that receive Make Ready assistance, there is no obligation for these charging stations to provide service to the public. The Company does not have a list, for example, of Make Ready sites that are open to the public for charging. There is also no evidence that the Make Ready sites will result in incremental load on the system that would fully recover the revenue requirement associated with the cost of Make Ready expenditures. The Company has not demonstrated that revenue collected through the Make Ready program will offset costs to ratepayers.

Q. WHICH GEORGIA POWER CUSTOMERS ARE RECEIVING THE BENEFITS OF MAKE READY?

A. As noted below, Georgia Power has not disclosed the names and locations of Make Ready locations. In Response to STF-PIA-1-1, the Facility Types for Make Ready participants was provided. These include:

1. Airport
2. College/University
3. Commercial Office/Workplace
4. Entertainment/Hospitality
5. Industrial
6. Mass Transit
7. Medical Campus
8. Multi-family/Apartment/Condo/Mixed-Use Development
9. Municipality
10. Other Commercial Business/Retail
11. Seaport
12. Supply Chain/Logistics

[26] STF-LA-6-20 Attachment B.docx

Participants include airlines, hotels, private golf clubs, private schools, automobile dealerships, luxury condominiums, and multi-national corporations with annual revenues well over a billion dollars.

Q. IS ANY OF THE REVENUE REQUIREMENT ON THE ELECTRIC TRANSPORTATION MAKE READY CAPITAL INVESTMENT BEING DIRECTLY RECOVERED FROM MAKE READY PARTICIPANTS WHO BENEFIT FROM THE PROGRAM?

A. No.[27]

Q. WHERE WOULD ELECTRIC VEHICLE OWNERS CHARGE IF THE MAKE READY PROGRAM IS DISCONTINUED?

A. In the absence of additional Make Ready enabled charging stations, Electric Vehicle owners will continue to charge primarily at home. They will also charge at new and existing stations being developed competitively across the state without Make Ready funding. It is expected that fueling stations and convenience stores are interested in deploying charging stations, even without funding from Georgia Power ratepayers.

Q. WHAT COSTS ARE BEING PASSED TO GEORGIA POWER'S RETAIL ELECTRIC CUSTOMERS?

[27] STF-PIA-1-3

A. The revenue requirement for the Make Ready program includes the capital expenditures to purchase and install the equipment, a rate of return to Georgia Power Company, depreciation, and taxes and the operating and maintenance expense of the program.

Q. HOW LONG WILL RATEPAYERS BE OBLIGATED TO PAY FOR THE MAKE READY EQUIPMENT?

A. Staff understands that the initial term for a participant is one year, with automatic renewals for ten years. It's not known what happens with the assets and program after ten years. Staff believes the revenue requirement will continue to be collected from ratepayers as long as the assets are owned and maintained by Georgia Power. Alternatively, the assets could be removed from the program or sold to the participant at market value.

Q. ARE THERE OTHER REASONS TO NOT MANDATE THAT RATEPAYERS SUBSIDIZE ELECTRIC VEHICLE CHARGING VIA THE MAKE READY PROGRAM?

A. Yes. The long-term success of the electric vehicle charging market depends on making it a competitive free market. Make Ready creates an uneven playing field for providers of Electric Vehicle Charging services, and gives Georgia Power the ability to select winners and losers in the charging station market. More importantly, GPC customers should have the economic freedom to only pay for the retail electric service they need. Customers who have no alternative for their electric service should not be required to also pay for other Georgia Power customers to have private Electric Vehicle charging stations.

Q. ARE THESE MAKE READY ASSETS OWNED AND MAINTAINED BY GEORGIA POWER, AND PAID FOR BY RATEPAYERS, USED AND USEFUL IN THE PROVISION OF REGULATED RETAIL ELECTRIC SERVICE?

A. No. The assets are only used to provide electric vehicle charging, which is currently not regulated.

Q. HAS THE COMPANY IDENTIFIED THE MAKE READY LOCATIONS?

A. In data request STF-PIA-1-1, Staff requested that the Company identify the ET Make Ready sites. In its response, the Company provided the "Premise Company" and "Contact Address". Make Ready assets are owned and maintained by Georgia Power. As such, the location of these assets should not be designated as trade secret. With very rare exception, the locations of Company-owned assets have not previously been withheld from the public. Staff subsequently requested the Company provide the addresses of the Make Ready projects as public disclosure information and without trade secret designation. The Company responded by indicating that by virtue of being collocated with participating Make Ready Customers, revealing the Make Ready sites would disclose customer information (i.e. which of its customers are Make Ready participants). Although Staff has recommended the Make Ready Program be discontinued, if the Commission chooses to approve the program, it should do so with full transparency required. The names and addresses of the participants should be disclosed, and the Company should also be required to identify which locations are available to the public for charging.

Q. IS IT CONCERNING THAT GEORGIA POWER IS NOT WILLING TO IDENTIFY THE MAKE READY SITES, AND THAT MAKE READY PARTICIPANTS DO NOT WANT IT KNOWN THEY ARE RECEIVING THE MAKE READY SUBSIDY?

A. Yes. It is concerning that the Make Ready locations have not been disclosed. While Staff understands the need to protect customer data in general, the participation in Make Ready should not fall into a category of private customer information. It is concerning the ratepayers who would pay for the monopoly utility to own and operate charging stations for the private benefit of other customers are not afforded the opportunity to know which customers are benefiting and where the funds are being deployed. Staff also notes that participants in the Make Ready Program have each agreed to the ET Make Ready Program Terms and Conditions, which includes the following provision:

> 6. Electric Transportation Data and Information. The Participant acknowledges and agrees that Georgia Power's collection of data associated with the Project is critical to the evaluation of the Make-Ready Program. The Participant hereby grants Georgia Power unrestricted access and use of all data collected by the ET Infrastructure. The Participant agrees to allow Georgia Power, its agents and representatives to use data gathered as part of the Make-Ready Program for use in regulatory reporting, ordinary business use, industry forums, case studies, or other similar activities, in accordance with applicable laws and regulations.

Participants have already granted Georgia Power use of data associated with its project. The address of the project is collected and is a component of how the program is structured, whether projects approved are geographically diverse and how charging may differ between various locations.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE THE CAPITAL COSTS ASSOCIATED WITH THE EV MAKE READY PROGRAM.

A. As shown on Staff Exhibit__(RS/RT-2), Schedule E-13, our recommended adjustment is in two parts. The first part of our adjustment is to remove the rate base components, which are comprised of plant in service and accumulated depreciation. The impact of removing the plant in service components of the EV Make Ready program results in retail electric rate base being decreased by $13.500 million, $40.500 million and $67.500 million for plan years 2023, 2024 and 2025, respectively.

In addition, as shown on Staff Exhibit__(RS/RT-2), Schedule E-14 (line 7), the second part of our rate base adjustment reduces retail electric accumulated depreciation (thus increasing rate base) by $196,000, $978,000 and $2.543 million for plan years 2023, 2024 and 2025, respectively. Our adjustments to accumulated depreciation were derived by our adjustment to depreciation expense, which is calculated by applying the Distribution depreciation rate that was supplied by Staff witness Lance Kaufman. As shown on Exhibit__(RS/RT-2), Schedule E-13 (lines 8-9) our adjustment reduces jurisdictional depreciation expense by $391,000, $1.173 million and $1.956 million for plan years 2023, 2024 and 2025, respectively.

<u>E-14, Electric Vehicles Community Charging Stations</u>

Q. WHAT PORTION OF GEORGIA POWER'S $30 MILLION REQUEST REPRESENTS SPENDING FOR COMMUNITY CHARGING STATIONS?

A. The projected capital expenditures for infrastructure upgrades for the Community Charging program is $3 million per year for years 2023 through 2025. Capital

expenditures for the Community Charging program include but are not limited to EV chargers, wires, panels, conduit, transformers, and labor.[28]

Q. HAS THE COMPANY IDENTIFIED ALL COSTS AND REVENUES FOR EV CHARGING FACILITIES THAT ARE INCLUDED IN RATE BASE, REVENUE AND OPERATING EXPENSES FOR THE FORECASTED TEST YEAR AND FOR CALENDAR YEARS 2023-2025?

A. Yes. In its response to STF-LA-2-120 Attachment, the Company provided the amounts summarized in the following table as being included in the forecasted test year and for calendar years 2022 through 2025:

EV Charging Stations						
	FERC Account	Test Year (Jul-22 - Jul-23)	2022	2023	2024	2025
Rate Base (13-month average)						
Plant in Service	101	$ 8,689,293	$ 7,364,160	$ 9,849,806	$ 12,849,806	$ 15,849,806
Accumulated Depreciation	108	(138,236)	(25,420)	(247,619)	(574,729)	(989,319)
ADITs	282	(1,003,749)	(877,250)	(1,099,098)	(1,378,891)	(1,722,723)
Net Rate Base		$ 7,547,308	$ 6,461,491	$ 8,503,089	$ 10,896,186	$ 13,137,764
Operating Income	FERC Account	Test Year (Aug-22 - Jul-23)	2022	2023	2024	2025
Revenue	456	$ (348,019)	$ (345,000)	$ (350,175)	$ (355,428)	$ (362,536)
O&M Expense	908	416,353	407,940	422,528	437,846	453,940
Depreciation Expense	403	242,837	196,351	283,370	370,850	458,330

Q. IN YOUR OPINION, SHOULD GEORGIA POWER BE AUTHORIZED TO MAKE ADDITIONAL CAPITAL INVESTMENTS IN THE COMMUNITY CHARGER PROGRAM?

A. No, they should not. First, the table above clearly demonstrates the current and future charging stations will not generate enough revenue to cover O&M expense and

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depreciation, much less the return on capital and income taxes associated with the investment. The Community Charging stations are being subsidized by all ratepayers including the vast majority who do not own an electric vehicle, and are not expected to own an electric vehicle in the next decade. Continuation of the program, and increasing the annual capital expenditures to $3 million annually will result in additional costs to ratepayers that exceed the programs revenue.

Second, the competitive market is expected to provide, with assistance from federal funding and grants, a significant number of new charging stations throughout the state, including those being installed by companies risking their own capital. It would be unfair and inappropriate regulatory policy to allow Georgia Power to expand its monopoly to build more EV charging facilities at the expense of ratepayers. To the extent that EV charging stations being used for the purpose of fueling the Company's fleet of vehicles that are used in the provision of providing service, such costs may be appropriate for recovery from ratepayers assuming the investment was prudent and economic, as these are used and useful. However, as discussed above, the Company's plan for the $9 million investment in EV charging facilities over the term of plan years 2023-2023, is largely centered on making such charging facilities available to portions of the general public that have EVs. Also, the rates that the Company is charging for EV charging for the service are insufficient to recover the costs, given the low utilization of the chargers. Staff recommends that the costs associated with the Company's Community Charging Stations program should not approved. Staff has therefore made an adjustment to remove the costs and revenues associated with the EV charging facilities.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE THE CAPITAL COSTS ASSOCIATED WITH THE EV CHARGING FACILITIES.

A. As shown on Staff Exhibit__(RS/RT-2), Schedule E-14, our recommended adjustment is in two parts. The first part of our adjustment is to remove the rate base components, which are comprised of plant in service and accumulated depreciation. The impact of removing the plant in service components of the EV charging facilities results in retail electric rate base being decreased by $1.500 million, $4.500 million and $7.500 million for plan years 2023, 2024 and 2025, respectively.

In addition, as shown on Staff Exhibit__(RS/RT-2), Schedule E-14 (line 7), the second part of our rate base adjustment reduces retail electric accumulated depreciation (thus increasing rate base) by $22,000, $109,000 and $283,000 for plan years 2023, 2024 and 2025, respectively. Our adjustments to accumulated depreciation were derived by our adjustment to depreciation expense, which is calculated by applying the Distribution depreciation rate that was supplied by Staff witness Lance Kaufman. As shown on Exhibit__(RS/RT-2), Schedule E-14 (lines 8-9) our adjustment reduces jurisdictional depreciation expense by $43,000, $130,000 and $217,000 for plan years 2023, 2024 and 2025, respectively.

<u>E-15, Operation and Maintenance ("O&M") Expense – Electric Vehicle Infrastructure</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO EV CHARGING EXPENSES?

A. As indicated in response to STF-PIA-3-5, the Company has proposed to include the following expenses in the 2023-2025 rate plan years:

Description	2023	2024	2025
Administrative Costs	$1,920,826	$2,242,116	$2,565,869
Infrastructure Maintenance	42,872	68,392	68,928
Rebates	2,815,000	2,879,745	2,945,979
Total O&M Expense per Company	4,778,698	5,190,253	5,580,776
Source: STF-PIA-3-5			

Q. WHAT AMOUNTS HAS THE COMPANY BOOKED IN PRIOR YEARS RELATED TO EV CHARGING EXPENSES?

A. In its response to STF-PIA-3-5 the Company stated that it booked the following EV Charging expenses for the years 2020, 2021 and 2022:

Description	2020	2021	2022
Administrative Costs	$1,453,275	$1,069,422	$1,084,037
Rebates	473,377	507,526	514,520
Total O&M Expense per Company	1,926,652	1,576,948	1,598,557
Source: STF-PIA-3-5			

Q. WHAT IS STAFF'S POSITION ON THE COMPANY'S REQUEST TO EXPAND EV CHARGING PROGRAMS?

A. As discussed previously in our testimony, Staff is recommending no ratepayer-funded expansion in EV charging programs. The Company's past expenditures should generally be sufficient for the test year and each of the rate plan years.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO O&M EXPENSE RELATED TO THE EV INFRASTRUCTURE.

A. We calculated a three-year average of the 2020-2022 administrative costs and applied this amount to each rate year. In addition, we accepted the Company's projected amounts for infrastructure maintenance. Finally, we multiplied the 2022 amount for rebates by two

and applied the result to each rate plan year. As shown on Exhibit__(RS/RT-2), Schedule E-15, the impact of our adjustments results in retail O&M expense being decreased by $2.505 million, $2.891 million and $3.281 million for plan years 2023, 2024 and 2025, respectively.

E-16 through E-29, O&M Expense Adjustments

Q. PLEASE EXPLAIN THE ADJUSTMENTS SHOWN ON SCHEDULES E-15 THROUGH E-29.

A. The amounts shown on Exhibit__(RS/RT-2), Schedules E-16 through E-29 are discussed in detail in the Direct Testimony of Staff witness Dante Mugrace who is recommending various adjustments to O&M expense. Specifically, Mr. Mugrace is recommending adjustments for the following O&M expenses:

- Schedule E-16 – O&M Expense - Transmission
- Schedule E-17 – O&M Expense - Distribution
- Schedule E-18 – O&M Expense – Customer Accounting
- Schedule E-19 – O&M Expense – Demonstration and Selling Expenses
- Schedule E-20 – O&M Expense – Administrative & General Salaries
- Schedule E-21 – O&M Expense – Office Supplies and Expense
- Schedule E-22 – O&M Expense – Outside Services Employed
- Schedule E-23 – O&M Expense – Injuries and Damages
- Schedule E-24 – O&M Expense – Employee Pensions and Benefits
- Schedule E-25 – O&M Expense – Customer Service and Information
- Schedule E-26 – O&M Expense – Miscellaneous General and Advertising

- Schedule E-27 – O&M Expense – Maintenance of General Plant
- Schedule E-28 – O&M Expense – Adjustment for Inflation
- Schedule E-29 – Labor O&M Expense – Vacancy Rate, Employee Levels, Performance Pay Plan and Overtime

The specific adjustments to these O&M expense accounts are shown on the referenced schedules in Exhibit__(RS/RT-2).

E-30, Transmission Plant Investment

Q. PLEASE EXPLAIN THE ADJUSTMENTS SHOWN ON SCHEDULE E-30.

A. The adjustments shown on Exhibit__(RS/RT-2), Schedule E-30 are discussed in detail in the Direct Testimony of Staff witnesses Paul Alvarez, Dennis Stevens and Raj Rana who are recommending adjustments to capital spending for transmission plant related to the GRID Investment Program proposed by Georgia Power. As shown on Staff Exhibit__(RS/RT-2), Schedule E-30, incorporating Messrs. Alvarez, Stevens and Rana's recommendations reduces the Company's retail electric transmission plant in service by $163.745 million for 2023, $484.508 million for 2024 and by $820.811 million for 2025. Messrs. Alvarez, Stevens and Rana are not recommending any adjustments to the forecasted test year.

E-31, Distribution Plant Investment

Q. PLEASE EXPLAIN THE ADJUSTMENTS SHOWN ON SCHEDULE E-31.

A. The adjustments shown on Exhibit__(RS/RT-2), Schedule E-31 are discussed in detail in the Direct Testimony of Staff witness Paul Alvarez, Dennis Stevens and Raj Rana who are recommending adjustments to capital spending for distribution plant related to the

GRID Investment Program proposed by Georgia Power. As shown on Staff Exhibit__(RS/RT-2), Schedule E-31, incorporating Messrs. Alvarez, Stevens and Rana's recommendations reduces the Company's retail electric distribution plant in service by $164.124 million for 2023, $523.165 million for 2024 and by $902.988 million for 2025. Messrs. Alvarez, Stevens and Rana are not recommending any adjustments to the forecasted test year.

E-32, Distributed Energy Resource Management System ("DERMS")

Q. PLEASE EXPLAIN THE ADJUSTMENTS SHOWN ON SCHEDULE E-32.

A. The adjustments shown on Exhibit__(RS/RT-2), Schedule E-32 are discussed in detail in the Direct Testimony of Staff witness Paul Alvarez, Dennis Stevens and Raj Rana who is recommending adjustments to capital spending for intangible plant related to the Distributed Energy Resource Management System ("DERMS") proposed by Georgia Power. As shown on Staff Exhibit__(RS/RT-2), Schedule E-32, incorporating Messrs. Alvarez, Stevens and Rana's recommendations reduces the Company's retail electric intangible plant in service by $4.974 million for 2023, $29.858 million for 2024 and by $74.633 million for 2025. Messrs. Alvarez, Stevens and Rana are not recommending any adjustments to the forecasted test year.

E-33, Transmission Plant - Depreciation Expense and Accumulated Depreciation

Q. PLEASE EXPLAIN YOUR ADJUSTMENT ON SCHEDULE E-33.

A. The adjustments shown on Schedule E-33 reflect corresponding adjustments to retail electric depreciation expense and accumulated depreciation which relate to Messrs. Alvarez, Stevens and Rana's recommended adjustments to capital spending for

transmission plant investment. Specifically, as shown on Exhibit__(RS/RT-2), Schedule E-33, line 5, retail electric depreciation expense for transmission is reduced $3.997 million for 2023, $11.831 million for 2024 and $20.047 million for 2025. The adjustments to depreciation expense use the transmission depreciation rate being recommended by Staff witness Kaufman.

In addition, as shown on Exhibit__(RS/RT-2, Schedule E-30, line 8, retail electric accumulated depreciation is reduced (thus increasing rate base) by $1.998 million for 2023, $9.910 million for 2024 and $25.846 million for 2025.

E-34, Distribution Plant - Depreciation Expense and Accumulated Depreciation

Q. PLEASE EXPLAIN YOUR ADJUSTMENT ON SCHEDULE E-34.

A. The adjustments shown on Schedule E-34 reflect corresponding adjustments to retail electric depreciation expense and accumulated depreciation which relate to Messrs. Alvarez, Stevens and Rana's recommended adjustments to distribution plant investment. Specifically, as shown on Exhibit__(RS/RT-2), Schedule E-34, line 3, retail electric depreciation expense for transmission is reduced $4.755 million for 2023, $15.159 million for 2024 and $26.164 million for 2025. The adjustments to depreciation expense use the distribution depreciation rate being recommended by Staff witness Kaufman.

In addition, as shown on Exhibit__(RS/RT-2, Schedule E-34, line 4, retail electric accumulated depreciation is reduced (thus increasing rate base) by $2.378 million for 2023, $12.335 million for 2024 and $32.996 million for 2025.

E-35, Intangible Plant - Amortization Expense and Accumulated Amortization for DERMS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT ON SCHEDULE E-35.

A. The adjustments shown on Schedule E-35 reflect corresponding adjustments to retail electric amortization expense and accumulated amortization which relate to Messrs. Alvarez, Stevens and Rana's recommended adjustments to remove the Company's proposed capital spending for DERMS investment, which the Company records as intangible plant. Specifically, as shown on Exhibit__(RS/RT-2), Schedule E-35, line 3, retail electric amortization expense for intangible plant is reduced $995,000 for 2023, $5.972 million for 2024 and $14.927 million for 2025. The adjustment to intangible plant amortization expense uses the five-year amortization rate for intangible plant that the Company identified it was using in response to informal follow-up by Staff.

In addition, as shown on Exhibit__(RS/RT-2, Schedule E-35, line 6, retail electric accumulated amortization is reduced (thus increasing rate base) by $497,000 for 2023, $3.972 million for 2024 and $14.390 million for 2025.

Q. WHY IS INTANIBLE PLANT BEING AMORTIZED RATHER THAN HAVING A DEPRECIATION RATE APPLIED TO IT?

A. As discussed previously, in an email received by Georgia Power dated October 17, 2022, the Company stated that it records the DERMS investment to intangible plant FERC account 303, but that intangible plant was excluded from the Company's depreciation rate study because it not subject to a depreciation rate. Rather, software and other intangible assets are amortized by the Company over a five-year period. Therefore, as

shown on Exhibit__(RS/RT-2), Schedule E-35, Staff's adjustment to remove the proposed DERMS investment from intangible plant is amortized over five years rather than by having a deprecation rate applied.

E-36, Depreciation Expense – Depreciation Rates Correction for Fort Benning and Fort Gordon

Q. PLEASE EXPLAIN YOUR ADJUSTMENT ON SCHEDULE E-36.

A. In the Company's response to STF-LA-8-18, discrepancies were noted between the depreciation rates proposed by Georgia Power in Attachment A to the response to STF-LA-8-18 and what was reflected in the Company's depreciation study for its Fort Benning and Fort Gordon solar facilities. Through an informal inquiry, Georgia Power advised that due to a formula error in its depreciation rate calculations, the depreciation rates reflected in its filing for Fort Benning and Fort Gordon were 2.584% and 0%, respectively. However, Appendix A to the depreciation study reflects depreciation rates of 2.835% and 2.820% for the Fort Benning and Fort Gordon solar facilities, respectively, which the Company confirmed are the correct rates to apply. The Company stated that it did not make this correction in its supplemental filing, thus their proposed depreciation expense is understated. Therefore, we are making an adjustment to reflect this correction.

As shown on Exhibit__(RS/RT-2), Schedule E-36, applying the correct depreciation rates to the Fort Benning and Fort Gordon solar facilities increases retail electric depreciation expense by $1.186 million for the test year and by $2.033 million for each plant year 2023, 2024 and 2025.

E-37, Property Tax Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPERTY TAX EXPENSE.

A. Staff's recommended adjustments decrease retail electric plant in service as it relates to the EV Make Ready Program, EV Community Charging Stations, and the adjustments to Transmission, Distribution and Intangible plant in service, requiring a corresponding adjustment to reduce retail electric property tax expense.

As shown on Exhibit__(RS/RT-2), Schedule E-37, the sum of the aforementioned adjustments to retail electric plant in service are multiplied by property tax rates that were supplied by Staff witness Dante Mugrace. After applying the retail electric jurisdictional factors, Staff's adjustment reduces retail electric property tax expense by $2.266 million for 2023, $7.219 million for 2024 and $12.726 million for 2025.

Excess Accumulated Deferred Income Taxes

Q. DID THE COMPANY HAVE EXCESS ACCUMULATED DEFERRED INCOME TAXES?

A. Yes. The Company's responses to STF-LA-2-101, STF-LA-2-102, STF-LA-2-115 and STF-LA-2-116 provide information on the Company's Excess Accumulated Deferred Income Taxes ("EADIT"). The Company will have completed its amortization of unprotected EADIT in 2022, and will continue to have amortization of protected EADIT in plan years 2023 through 2025, as shown in the above-noted responses.

Q. IS STAFF RECOMMENDING ANY ADJUSTMENT FOR EADIT AMORTIZATION IN THE CURRENT RATE CASE?

A. No. The amortization of the unprotected EADIT through December 2022 is consistent with the treatment provided for in the Commission Order in Docket No. 42516, which provided that the Company would amortize the benefit of unprotected EADIT for the benefit of customers over the three-year period ending December 2022, as further explained in the Company's response to STF-LA-2-115.

The amortization or protected EADIT is subject to certain normalization requirements, which include utilizing the average rate assumption method ("ARAM") to amortize the protected EADIT. The use of the ARAM for protected EADIT results in that being amortized in annual amounts that can differ from year to year in total such that the protected EADIT gets amortized over a period that approximates the remaining useful life of the utility plant to which the protected EADIT is attributable. The Company will continue to be amortizing the protected EADIT using the average rate assumption method which is required by the Internal Revenue Service. Accordingly, the Company has projected protected EADIT amortization of approximately $66 million for the test year and for 2023, and approximately $67 million for 2024 and approximately $69 million for 2025, which have been reflected in the Company's filing as a reduction to income taxes. Because the impacts of the continuing amortization of protected EADIT using the ARAM appears to have been properly and reasonably reflected in the Company's application, Staff is not recommending any further adjustments related to protected EADIT amortization in the current rate case.

E-38, Energy Storage and Solar Production Tax Credits under the Inflation Reduction Act

Q. DOES THE COMPANY EXPECT TO HAVE ENERGY STORAGE AND SOLAR PRODUCTION TAX CREDITS UNDER THE INFLATION REDUCTION ACT OF 2022?

A. Yes. The Company's responses to STF-LA-5-14 and, STF-LA-5-15, indicate that the Company expects to have energy storage tax credits of $31.7 million in 2023 and solar production tax credits of $0.4 million in 2025 under the Inflation Reduction Act.

Q. HAS STAFF REFLECTED ADJUSTMENTS TO INCOME TAXES FOR THOSE EXPECTED ENERGY STORAGE TAX CREDITS AND SOLAR PRODUCTION TAX CREDITS?

A. Yes. As shown on Exhibit__(RS/RT-2), Schedule E-38, Staff has reduced income tax expense by $31.7 million in 2023 for the expected impact of the energy storage tax credits of $31.7 million in 2023 and reduced income tax expense in 2025 by $0.4 million for the expected solar production tax credits. As explained in the Company's response to STF-LA-5-14(b) concerning Energy Storage Credits and Solar Credits:

> b. At this time, the Company has identified approximately $33 million of total potential benefits for 2022 through 2025 for the Commission's consideration related to projected, qualified renewable and electric vehicle investments. Listed below are the capital investments, along with estimated tax savings by year for 2022 through –2025, of the incremental benefits the Company has identified from the IRA, with related assumptions.

Capital Investments (in millions)	2022	2023	2024	2025
Energy Storage	$ -	$ 105.6	$ -	$ -
Solar Qualifying for Production Tax Credits	$ -	$ -	$ -	$ 32.7
EV Chargers	$ 2.0	$ 3.0	$ 3.0	$ 3.0

Potential Tax Credits (in millions)	2022	2023	2024	2025
Energy Storage Credits	$ -	$ 31.7	$ -	$ -
Solar Credits	$ -	$ -	$ -	$ 0.4
EV Charger Credit Amortization	$ 0.1	$ 0.2	$ 0.2	$ 0.3

Energy Storage Credits: The IRA provides Investment Tax Credits ("ITC") for standalone energy storage systems, no longer requiring it to be paired with and charged by solar generation. The Company believes the 65 MW Mossy Branch battery storage project, which is projected to be on-line in 2023, will qualify for a 30% ITC. The IRA also gives an "opt-out" from the existing ITC normalization, which permits the Company to recognize the full ITC benefit in the year the project goes into service, thereby providing a benefit to customers by lowering the levelized cost of electricity over the life of the project as compared to the cost under the existing ITC normalization option. In order to take advantage of this "opt out" option offered in the IRA, the Commission must specifically approve the "opt-out" option. The Company's calculation above assumes that the full $31.7 million of estimated credit resulting from the normalization opt-out option would be recognized in 2025.[29]

Solar Credits: The IRA provides a PTC option, which may be utilized instead of the existing normalized ITC for solar investments. The Company estimates the PTC option will provide an approximate $0.4 million of additional benefits for customers in 2025 on projected self-build ash pond solar investments compared to the normalized ITC option.

[29] The Company confirmed in response to an informal follow-up that this should state 2023, not 2025.

Note that the Company's table shows the $31.7 million for Energy Storage Credits in 2023, whereas the last sentence in the Company's response to STF-LA-5-114(b) concerning those credits states that: "The Company's calculation above assumes that the full $31.7 million of estimated credit resulting from the normalization opt-out option would be recognized in 2025." In response to a Staff informal request for clarification from the Company about the latter date, the Company confirmed that this should be for 2023, as shown in the Company's table, not in 2025, which apparently was a typo. Accordingly, Staff has reflected the $31.7 million in Energy Storage Credits as a reduction to income tax expense in 2023.

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Q. DOES THE COMPANY ALSO EXPECT TAX CREDITS FOR EV CHARGERS?

A. Yes. The Company's response to STF-LA-5-114(b) also indicates that the Inflation Reduction Act extends and modifies the tax credit for alternative fuel refueling property. The Act provides for a 30% investment tax credit for alternative fuel refueling property placed into service through 2032 and increases the credit limitation to $100,000 per EV charger. The Company is required to normalize the EV charger related investment tax credits over the life of the assets, and has indicated that it expects an additional $0.8 million of total EV investment tax credit amortization in 2022-2025. The Company's response to STF-LA-5-14(b) indicates the amount of ITC amortization that is expected for each year. In general, the annual ITC amortization for each year would reduce income tax expense in that year.

Q. HAS STAFF REFLECTED A REDUCTION TO INCOME TAX EXPENSE FOR THE EV CHARGER RELATED INVESTMENT TAX CREDIT AMORTIZATION THAT GEORGIA POWER HAS IDENTIFIED AS AN ADDITIONAL $0.8 MILLION OF TOTAL AMORTIZATION IN 2022-2025?

A. No. Consistent with Staff's recommendation that ratepayers not be required to pay for EV Charger related investment costs projected by the Company for 2023 through 2025, Staff has not reflected amortization of additional EV Charger related ITC as a reduction to income tax expense in the 2023 through 2025 plan years. However, if some portion of the Company's projected investment for EV charging for the 2023 through 2025 plan years were to be allowed to be charged to ratepayers, under those circumstances, Staff believes that reflecting the impact of the amortization of the related ITC from that EV Charger investment as a reduction to income tax expense would be appropriate.

Q. DID STAFF ASK THE COMPANY ABOUT OTHER POTENTIAL IMPACTS FROM THE INFLATION PROTECTION ACT ON INCOME TAXES?

A. Yes. Staff data request STF-LA-8-13 asked the Company about a minimum federal corporate income tax provision of the Inflation Protection Act, specifically whether that is expected to have any impact on the Company's income taxes for any plan years. The Company's response to STF-LA-8-13 states that:

> The minimum corporate income tax rate provisions of the Inflation Reduction Act are effective beginning in 2023. The Company is currently awaiting further guidance from the U.S. Department of the Treasury on the corporate minimum tax; however, at this time, the Company does not expect to pay any corporate minimum income taxes for years 2023 through 2025.

Based on the Company's response to STF-LA-8-13, it does not appear that the corporate minimum tax provisions in the Inflation Protection Act are expected to result in the Company paying any corporate minimum taxes for years 2023 through 2025.

Production Tax Credits

Q. DID THE COMPANY HAVE PRODUCTION TAX CREDITS IN 2021?

A. Yes. The Company's response to STF-LA-2-117 indicates that the Company had $9,878 of Production Tax Credits ("PTCs") related to hydro generation in 2021. The Company's response to STF-LA-2-119 indicates that the Company had PTCs related to hydro units in a carry-forward position at both December 31, 2020 and December 31, 2021 of $743,661.

Q. DOES THE COMPANY ANTICIPATE PTC'S FROM VOGTLE UNITS 3 AND 4?

A. Yes. The Company's response to STF-LA-2-118 indicates that it projects receiving PTCs for Vogtle Units 3 and 4 of $26.1 million in the forecasted test year, $58.7 million in 2023 and $127.6 million in both 2024 and 2025. However, that response also indicates that the PTC's for Vogtle Units 3 and 4 are excluded from the Company's filing.

Q. HAS STAFF MADE AN ADJUSTMENT TO REFLECT PTC'S IN THE TEST YEAR OR PLAN YEARS?

A. No. The amount of hydro PTCs in 2021 was fairly small and the Company's response to STF-LA-2-118 indicates that $0 PTCs are expected in 2022. While an adjustment could potentially be made to reflect some amount of hydro PTCs in the test year and plan years, it appears that the amount would be de minimus, so Staff has not made an adjustment.

As noted in the Company's response to STF-LA-2-118, PTCs related to Vogtle Units 3 and 4 are expected to be very significant -- the Company projects $58.7 million for 2023 and $127.6 million in both 2024 and 2025, and will need to be factored in when costs for Vogtle Units 3 and 4 are reflected in base rates, i.e., if the projected in-service dates of March 2023 and December 2023, respectively, hold up, in the context of addressing the Vogtle Unit 3 and 4 related rate increase. However, in the context of the current rate case, the in-service costs of Vogtle Units 3 and 4 have been excluded. Staff is therefore not proposing an adjustment to reflect PTCs from Vogtle Units 3 and 4 in the 2024 or 2025 plan years for purposes of computing the Company's base rate revenue requirement in the current case.

Plant Held for Future Use

Q. WHAT AMOUNT OF PLANT HELD FOR FUTURE USE ("PHFFU") HAS THE COMPANY REFLECTED IN RATE BASE?

A. The Company reflected approximately $106.5 million of PHFFU in rate base in the test year and in 2023, $106.4 million in 2024 and $106.3 million in 2025.

Q. WHAT AMOUNT OF PHFFU IS SHOWN ON THE COMPANY'S 2021 FERC FORM 1?

A. The Company's 2021 FERC Form 1 shows $106,608,388 of PHFFU. A copy of that page is presented in Exhibit __(RS/RT-17).

Q. WHAT IS SHOWN IN EXHIBIT__(RS/RT-18)?

A. Exhibit RS/RT-18 uses information from the Company's 2021 FERC Form 1 concerning Plant Held for Future Use (see, e.g., Exhibit RS/RT-17) to identify the cost of PHFFU that show an "expected use" date of (1) 2030 or beyond and (2) 2040 or beyond. As shown there, of the $106.6 million of PHFFU, approximately $91.6 million or 86% has an "expected use" date of 2030 or beyond and approximately $64.2 million or 60% has an "expected use" date of 2040 or beyond. If PHFFU were to be included in rate base to earn a full return for investors for multi-decade periods, the cost to ratepayers will add up to significant amounts.

Q. WHAT ARE STAFF'S CONCERNS REGARDING THE COMPANY'S PHFFU?

A. Staff is concerned that the "expected use" dates keep getting pushed off further and further into the future, such that land acquired for future use is sitting in the PHFFU account and being included in rate base to earn a return for investors for extended multi-decade periods in some instances. A large portion of the Company's PHFFU at December 31, 2021 for example has projected use dates of 2030 or beyond, and over 60% of the total PHFFU cost is for projects which have "expected use" dates of 2040. Additionally, the PHFFU includes about $22.9 million for a future generating plant site in Stewart County, Georgia; however, the Company has no plans to construct generation there, nor has the Commission approved the construction of a new generating plant at that site. To the extent that the Company does not have firm plans at this time to construct a new generating plant on the Stewart County site within a reasonable planning period, Staff recommends that the Company evaluate whether the costs of that site should be transferred to a non-utility property account.

Q. DID THE COMMISSION ADDRESS PHFFU IN THE COMPANY'S 2019 RATE CASE IN DOCKET NO. 42516?

A. Yes. The Commission addressed PHFFU in the Company's 2019 rate case in Docket No. 42516. Specifically, pursuant to the Settlement Agreement reached in that case, as noted in Section 9 (pages 8-9) of the Commission's Short Order Adopting Settlement as Modified, the Commission stated:

> With the exception of easements and right of ways, Generation and Transmission property in Plant Held for Future Use ("PHFFU") that has been held in PHFFU account for 15 consecutive years shall undergo review during the first IRP proceeding the 15th year that such property has been held in PHFFU. Distribution property in PHFFU that has been held in PHFFU account for 15 consecutive years shall undergo review during the first base rate proceeding following the 15th year that such property has been held in PHFFU. In the respective proceeding, the Company will be required to present the specific plan for the property(s) that has exceeded 15 consecutive years in PHFFU. The Commission will decide the matter in that proceeding.

Q. IS STAFF RECOMMENDING AN ADJUSTMENT TO PHFFU IN THE CURRENT PROCEEDING?

A. Not at this time. As described in the passage above from the Commission's Short Order Adopting Settlement as Modified in Docket No. 42516, the Company will be required to present a specific plan for any Generation and Transmission properties that have been held in PHFFU for a period that has exceeded 15 consecutive years in the 2025 IRP. In addition, the Commission's directive will also apply to Distribution property that has been held in PHFFU for a period exceeding 15 years in Company's next base rate case proceeding.

XI. AFFILIATE CHARGES TO GEORGIA POWER COMPANY AND GEORGIA POWER COMPANY CHARGES TO AFFILIATES

Overview of Affiliate Charges from Southern Company Services and Southern Nuclear Operating Company to Georgia Power Company

Q. PLEASE DESCRIBE THE COSTS THAT GEORGIA POWER INCURS INDIRECTLY THROUGH CHARGES FROM SOUTHERN COMPANY SERVICES AND SOUTHERN NUCLEAR OPERATING COMPANY.

A. In addition to the charges that it incurs directly, Georgia Power incurs costs from two affiliated centralized service companies, SCS and SNOC. These two affiliates provide management and technical services to both regulated and non-regulated Southern Company affiliates. These two affiliates charge Georgia Power and the other Southern Company affiliates directly for services provided specifically to each affiliate and then allocate the remaining indirect costs incurred each year to all appropriate affiliates on the basis of various allocation factors.

The SCS cost and allocation methodologies are detailed in the SCS Cost Control and Accountability Manual ("SCS CAM"), which is revised each year to reflect more recent data and changes in the Southern Company affiliate chart. The Company has designated the SCS CAM as Trade Secret information.

The SNOC cost and allocation methodologies are detailed in the SNOC Classification of Accounts Manual ("SNOC CAM"), which is also revised each year to reflect more recent data and any other accounting or allocation changes. The Company does not consider the SNOC CAM to be trade secret information.

Southern Company Services Charges to Georgia Power Company

Q. PLEASE DESCRIBE THE SCS COST ALLOCATION METHODOLOGIES.

A. SCS provides services to numerous Southern Company affiliates pursuant to Service Agreement contracts entered into between SCS and each of those affiliates, including Georgia Power. The SCS Service Agreement with Georgia Power states that SCS will provide to Georgia Power the following services at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations.

The costs incurred by SCS are tracked through work orders. Work orders are unique accounts in which the costs for various SCS work activities are collected. The costs then are charged from these work orders to the Southern Company affiliates that use those specific services or cause those costs to be incurred by SCS. For those costs that are not directly charged to the various affiliates for services provided specifically to an affiliate or affiliates, SCS applies an allocation factor to each work order. These factors are used to allocate the SCS work order costs to each affiliate that caused the costs to be incurred. For calendar year 2021, SCS used 21 basic allocation factors to charge costs to the various affiliates. We have attached a description of these allocation factors provided by SCS in its Form 60 public filing with the Federal Energy Regulatory Commission ("FERC") as our Exhibit__(RS/RT-21). We do not propose any adjustments for the allocation factors selected and applied by SCS as discussed below.

Q. DOES SCS REPORT THE COSTS THAT IT CHARGES TO EACH OF THE OTHER SOUTHERN COMPANY AFFILIATES?

A. Yes. SCS files a Form 60 with the FERC each year, which details the costs that it incurred and the amounts that it charged to the other Southern Company affiliates. SCS reported in its 2021 Form 60 at page 307 that it incurred and billed $1.945 billion in costs. SCS charged Georgia Power $662.99 million of those costs, or 34.09 percent of the total incurred by SCS:

Description	Amount	Reference
SCS Total Amount Billed in 2021	$ 1,944,673,043	(1)
Billed to Georgia Power Company	$ 662,988,379	(1)
Percentage of Total SCS Billed to Georgia Power Company	34.09%	
(1) SCS FERC Form 60 for year 2021, page 307		

Georgia Power charged the $662.99 million to various capital and expense accounts.

SCS Allocation Factors Using 2022 Statistics

Q. HOW DID THE SCS POPULATE THE ALLOCATION FACTORS IN THE YEARS PRIOR TO 2017?

A. In the years prior to 2017, for Fixed Percentage Allocations, SCS used statistics that were based on a single year with a one-year lag. For example, in Georgia Power's 2013 rate case in Docket No. 36989, the 2014 SCS allocations in the Company's projected test year in that prior rate case were based on 2012 statistics, thus the charges included in the Company's expenses were based on outdated data. As a result, it was necessary to make an adjustment to the SCS allocation factors using more recent data.

Q. DOES SCS STILL USE STATISTICS BASED ON A SINGLE YEAR WITH A ONE-YEAR LAG IN DETERMING ITS ALLOCATION FACTORS?

A. No. As explained in the SCS FERC Form 60 for 2021 at page 402, SCS uses statistics based on previous year statistics. For example, the SCS allocations in 2021 were based on 2020 statistics. In the Company's response to STF-LA-2-111, which asked whether SCS has updated any of its allocation factors for use in 2022, the Company provided supporting calculations for each SCS allocation factor as of May 2022. In Attachment SCS-LA-2-111, the data on which the SCS allocation factors for May 2022 was calculated was based on 2021 statistics.[30]

Q. DID YOU REVIEW THE SCS CHARGES TO GEORGIA POWER TO ENSURE THAT NO LOBBYING EXPENSE, CHARITABLE CONTRIBUTIONS OR OTHER BELOW-THE-LINE AMOUNTS WERE INCLUDED IN TEST YEAR EXPENSES?

A. Yes. We confirmed through discovery that SCS identifies all such charges and that Georgia Power did not include these below-the-line amounts in test year expenses.

Q. DID YOU REVIEW THE SCS CHARGES TO GEORGIA POWER FOR CERTAIN INCENTIVE COMPENSATION COSTS?

A. Yes. We address this issue in another section of our testimony. It is not limited to the SCS charges to Georgia Power, and also includes similar costs incurred directly by

[30] The Excel file attachment to the response to STF-LA-2-111 provided supporting calculations for each SCS allocation factor as of May 2022, which was based on 2021 statistics.

Georgia Power, and incentive compensation costs charged to Georgia Power Company from Southern Nuclear Operating Company.

Southern Nuclear Company Charges to Georgia Power Company

Q. PLEASE DESCRIBE THE SNOC COST ALLOCATION METHODOLOGIES.

A. SNOC provides services to both Georgia Power and Alabama Power Company in support of the Hatch, Vogtle and Farley nuclear generating facilities in Georgia and Alabama. The Service Agreement between SNOC and Georgia Power states that SNOC will provide the following nuclear-related services to Georgia Power at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations.

Similar to SCS, SNOC collects the costs it incurs in numerous work orders. For many of the work orders, the costs are charged directly to the individual generating facilities because the SNOC activities are performed specifically for certain facilities. The remaining costs are charged two-thirds to Georgia Power and one-third to Alabama Power based on the number of plant sites (see additional discussion below). SNOC has other allocation factors available, but uses the number of plant sites for administrative simplicity.

Q. DOES SNOC HAVE ANY SUBSIDIARIES?

A. Yes. On February 23, 2006, SNOC organized a wholly-owned subsidiary, Southern Nuclear Development, LLC ("SND"), to manage Southern's new nuclear generation development activities. On July 1, 2006, SNOC organized Southern Nuclear Services, LLC ("SNS"), a wholly-owned subsidiary. SNS assumed a contract with Pooled Equipment Inventory Company ("PEICo") from Southern Management Development, Inc., an affiliated company. The contract provides for SNS to receive a fixed monthly fee from PEICo in exchange for providing the following services: project management; quality assurance; storage, maintenance, and insurance; and administration.

Q. ARE SOME OF SNOC'S COSTS ALLOCATED TO THOSE SUBSIDIARIES?

A. Yes.

Q. DOES SNOC ALSO REPORT THE COSTS THAT IT CHARGES TO GEORGIA POWER AND ALABAMA POWER?

A. Yes. SNOC also files a Form 60 with the FERC each year, which details the costs that it incurred and the amounts that it charged to Georgia Power and Alabama Power and other affiliates such as SCS, and the SNOC subsidiaries, SND and SNS. SNOC reported in its 2021 Form 60 at page 307 that it incurred $1.172 billion in costs. SNOC charged Georgia Power $906.2 million of those costs, consisting of both capital and expense amounts.

Q. HOW DOES SNOC ALLOCATE COSTS?

A. As described on page 402 of SNOC's 2021 FERC Form 60, for SNOC corporate departments and functional areas benefitting all operating plants, the SNOC costs are allocated using a Plant Basis Method, which is determined by dividing one plant by the total number of plants. The use of the number of plant sites allocation factor generally benefits Georgia Power through lower charges compared to alternative allocation factors that are available and could have been used.

Q. BASED ON SNOC CHARGES BEING ALLOCATED USING THE PLANT BASIS METHOD, DOES GEORGIA POWER CURRENTY RECEIVE A TWO-THIRDS ALLOCATION OF SNOC CHARGES BASED ON HAVING FOUR OF THE SIX OPERATING NUCLEAR UNITS?

A. Yes. As noted above, SNOC provides services to both Georgia Power and Alabama Power Company. Georgia Power owns Hatch Units 1 and 2 and Vogtle Units 1 and 2 whereas Alabama Power Company owns Farley Units 1 and 2. As a result, since Georgia Power owns four of the six nuclear units currently operating, it receives a two-thirds share of the SNOC allocated costs.

Q. HAS THE COMPANY INDICATED WHEN IT EXPECTS VOGTLE UNITS 3 AND 4 TO ACHIEVE COMMERCIAL OPERATION?

A. Yes. In its response to STF-LA-2-118, the Company stated that the projected in-service date for Vogtle Unit 3 is March 2023 and the projected in-service date for Vogtle Unit 4 is December 2023.

Q. WILL THE SNOC PLANT BASIS ALLOCATION FACTOR BE UPDATED WHEN VOGTLE UNITS 3 AND 4 ACHIEVE COMMERCIAL OPERATION?

A. Yes. According to the response to STF-1-43 in Docket No. 44265, upon Vogtle Unit 3 achieving commercial operation (currently expected to be March 2023), the SNOC allocations will be as follows:

Alabama Power Plant Farley Unit 1	14 1/7%
Alabama Power Plant Farley Unit 2	14 1/7%
Georgia Power Plant Hatch Unit 1	14 1/7%
Georgia Power Plant Hatch Unit 2	14 1/7%
Georgia Power Plant Vogtle Unit 1	14 1/7%
Georgia Power Plant Vogtle Unit 2	14 1/7%
Georgia Power Plant Vogtle Unit 3	14 1/7%
Total SNOC Allocation	100.00%

In addition, upon Vogtle Unit 4 achieving commercial operation (currently expected to be December 2023), the SNOC allocations will be as follows:

Alabama Power Plant Farley	25%
Georgia Power Plant Hatch	25%
Georgia Power Plant Vogtle Units 1&2	25%
Georgia Power Plant Vogtle Units 3&4	25%
Total SNOC Allocation	100%

Q. DID YOU REVIEW THE SNOC CHARGES TO GEORGIA POWER FOR THE TEST YEAR?

A. Yes. We have adjusted for the SNOC charges included in the test year for the stock-based incentive compensation expense. We address the stock-based incentive compensation expense in another section of our testimony.

Georgia Power Company Charges to Other Affiliates

Q. PLEASE DESCRIBE THE SERVICES PROVIDED BY THE COMPANY TO OTHER SOUTHERN COMPANY AFFILIATES.

A. Georgia Power operates and maintains the generating facilities that are owned by Southern Power Company ("Southern Power") and physically located in Georgia. These Southern Power generating facilities are located at Plants Dahlberg, Franklin and Wansley.

Q. PLEASE DESCRIBE THE METHODOLOGY EMPLOYED BY GEORGIA POWER TO DETERMINE THE COSTS OR PRICES CHARGED TO OTHER SOUTHERN COMPANY AFFILIATES FOR THE SERVICES IT PROVIDES.

A. The Company generally charges the cost it incurs to provide the services to the other affiliates, although certain of its service agreement contracts with the other affiliates include a test of that cost against market to guard against subsidization of its non-regulated affiliates. For example, the Company's service agreement with Southern Power states that: "As compensation for such services or the market value thereof, whichever is higher."

Although the methodology for quantifying cost is not defined in the Company's Service Agreement contracts with the other affiliates, we have reviewed the methodology used by the Company for charges to the other affiliates. The Company determines its "cost" on a comprehensive basis. Cost includes the direct costs to provide the services, including a return of and on all investment costs, and indirect costs, including labor payroll taxes, benefits, and other corporate overheads. The overheads include an allocation of administration and general expenses, which in turn include amounts initially charged to Georgia Power by SCS.

Georgia Power Company Charges to Southern Power

Q. DID YOU REVIEW THE COMPANY'S PROCEDURES FOR CHARGING COSTS TO SOUTHERN POWER COMPANY?

A. Yes. The previous agreement between Georgia Power and Southern Power was terminated in August 2007, and replaced with a new service contract. Under the service contract, the Company provides and bills Southern Power for specifically requested services.

The Georgia Power General Accounting Procedure ("GAP") 58 describes accounting for work performed by Georgia Power Company on behalf of other companies. The methodology used by Georgia Power to charge Southern Power appears to be comprehensive and includes Georgia Power overheads, both those incurred directly by Georgia Power and those incurred indirectly through charges to Georgia Power from SCS.

GAP 58 at pages 1 and 2 states in part that:

> Upon request, the Company may provide services to associated companies within Southern Company. Reference "Requesting Services" for the types of services provided. The associated companies are Southern Company Services, Alabama, Gulf[31] and Mississippi Power Companies, Southern Telecom, Southern Company Management Development, Southern LINC Wireless, Southern Power, and Southern Nuclear. With the acquisition of Southern Company Gas, the associated companies now also include GAS and its subsidiaries.
>
> The Company may also provide resources and employees to companies not part of The Southern Company (non-associated companies). This includes any government agencies, other utilities, industrial businesses, etc.

[31] Gulf Power Company was sold to NextEra Energy on January 1, 2019.

Company policies and guidelines documented in this procedure apply to associated operating companies and non-associated companies. When a particular process varies between the companies, GAP 58 will be the authority.

GAP 58 at page 4 states that:

> In accordance with Georgia Public Service Commission (GPSC) guidelines, Docket No. 9355-U, the Company may provide services, properties and resources to associated companies on an actual cost basis (which includes a provision for applicable overheads).
>
> These services to associated companies, excluding SPC, include but are not limited to: website design, sale of materials associated with a service, printing, communication materials, fleet operations, calibration, substation outages, equipment repair, intercompany awards, training activities, etc.
>
> Per the Services Agreement between SPC and GPC dated August 1, 2007, services available to SPC include labor, environmental, general construction and advisory, property accounting and other services requested by SPC.
>
> For non-associated companies, services available and the cost of those services are in accordance with the contract price & terms.
>
> When specifically requested, the Company may also loan employees to other companies. These employees will be under the sole supervision and control of that company until the assigned work is completed.

GAP 58 at page 5 describes the billing for such services as follows:

> Under a cost plus basis:
>
> - The requesting company pays the amount based on actual charges to the job, which may be more or less than the original estimate. For Southern Company Gas, if costs exceed the original estimate by more than 120%, written approval must be obtained from GAS for the extra costs.
> - Construction services for non-associated companies are billed under this method.
>
> Under contract price billing:
>
> - The requesting company pays the estimated amount, regardless of the actual cost.

- Non-construction services for non-associated companies are billed under this method.

The Company has indicated that it is following the above-described guidance; however, this was not reviewed in detail concerning budgeted amounts for the projected test year or rate year costs.

XII. INCENTIVE COMPENSATION

Q. PLEASE IDENTIFY THE SOUTHERN COMPANY INCENTIVE COMPENSATION PLANS, THE COSTS OF WHICH ARE INCLUDED IN THE COMPANY'S TEST YEAR EXPENSES.

A. Southern Company has one primary incentive compensation plan, the Southern Company Omnibus Incentive Compensation Plan, but three types of incentive compensation programs pursuant to that plan. These programs are the Performance Pay Program ("PPP"), and the Long-Term Incentive Program, which is comprised of Performance Shares Units ("PSU") and Restricted Stock Units ("RSU"). Georgia Power's response to STF-LA-2-78(a)[32] provided the following descriptions of these plans:

Program Name	Description
Performance Pay Program	The Company's annual performance program rewards achievement of operational goals, earnings per share and GPC net income. A target percentage of base pay is established for each employee based on his/her classification and grade level for target-level performance. All employees except a small number of sales-commission employees are eligible to participate.
Long-Term Incentive Program	The Long-Term Incentive Program is a long-term, target-based, variable pay program for granting equity compensation awards that are paid in shares of common stock of Southern Company. The objective of the Long-Term Incentive Program is to promote strong long-term business results by rewarding continued employment and value drivers that distinguish our performance in the utility industry. Employees classified as exempt under FLSA with a minimum salary range of $132,299 (Grade 9) or greater are eligible. A long-term performance target percentage of base pay is established for each employee based on his/her grade level. Further, this target percent is allocated between performance shares (70%) and restricted stock units (30%).

[32] See Exhibit RS/RT-7 for copies of Company responses to Staff discovery relating to incentive compensation and stock-based compensation.

Stock Based Compensation

Q. DID THE COMPANY PROVIDE DOCUMENTATION WHICH DESCRIBES ITS LONG-TERM INCENTIVE PROGRAM?

A. Yes. A copy of the 2022 Southern Company Long-Term Incentive Program ("LTIP") was provided in Trade Secret Attachment STF-LA-2-78 Attachment C to the response to STF-LA-2-78.

Q. WHAT IS THE PURPOSE OF THE LTIP?

A. On page 2 of the LTIP, under the heading "Program Purpose" it states:

[*BEGIN TRADE SECRET*]

[redacted]

[*END TRADE SECRET*]

Q. PLEASE DESCRIBE THE SPECIFIC STOCK BASED COMPENSATION PROGRAMS.

A. The PSUs and the RSUs together constitute the Company's long-term incentive compensation programs for higher level employees at Georgia Power, SCS and SNOC. Specifically, as discussed on page 3 of the LTIP, **[*BEGIN TRADE SECRET*]** [redacted]

[redacted] **[*END TRADE SECRET*]**

Georgia Power's response to STF-LA-2-78, attached hereto as Exhibit__(RS/RT-7), provided, among other information, the dollar amounts for the test year ending July 31, 2023 as well as for calendar years 2023, 2024 and 2025 for each of the long-term incentive compensation programs.

Q. IN PRIOR RATE CASES, THE COMPANY'S LONG-TERM INCENTIVE PROGRAM INCLUDED STOCK OPTIONS. ARE STOCK OPTIONS INCLUDED IN THE COMPANY'S REVENUE REQUIREMENT IN THE CURRENT PROCEEDING?

A. No. According to the Company's response to STF-LA-2-92, in 2014 the Southern Company discontinued granting stock options and the program is no longer active. As a result, there are no costs related to stock options included in the Company's revenue requirement for the test year ending July 31, 2023 or in the rate plan years 2023-2025 in the current proceeding.

Q. PLEASE DISCUSS THE PERFORMANCE SHARE UNITS AND HOW THEY FUNCTION RELATIVE TO THE FINANCIAL PERFORMANCE OF SOUTHERN COMPANY.

A. Page 7 of the LTIP it states that **[*BEGIN TRADE SECRET*]** [redacted][33]

Q. PLEASE DESCRIBE THE CREDIT QUALITY THRESHOLD GOAL.

[33] [redacted]

[redacted]

[*END TRADE SECRET*]

Q. PLEASE DISCUSS THE RESTRICED STOCK UNITS AND HOW THEY FUNCTION RELATIVE TO THE FINANCIAL PERFORMANCE OF SOUTHERN COMPANY.

A. As noted above, **[*BEGIN TRADE SECRET*]** [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[*END TRADE SECRET*]

Q. HAD GEORGIA POWER REMOVED STOCK-BASED COMPENSATION EXPENSE FROM ITS ANNUAL SURVEILLANCE REPORTS IN THE YEARS SUBSEQUENT TO THE 2013 RATE CASE?

A. Yes. In Georgia Power's ASRs that were filed for calendar years 2014 through 2019, the Company had removed stock-based compensation pursuant to the Commission's Order in Docket No. 36989. The Commission adopted a Settlement Agreement in its Order Adopting Settlement Agreement dated December 23, 2013. In the Findings of Fact section of that Order, the Commission identified adjustments that had been recommended by Staff in Georgia Power's 2013 rate case and included as provisions to the Settlement Agreement. One such adjustment was to remove stock-based compensation from the Company's ASR going forward. Specifically, on page 9 of the Commission's Order, the Commission, referencing Exhibit A to the Settlement Agreement, states in part:

> Paragraphs 2 and 3 of the Settlement Agreement describe and provide that the Annual Surveillance Report ("ASR") will be filed by the Company by March 15 of the year following the reporting year. The Commission finds

> that the adjustments to the Company's initial filing agreed to in the Settlement Agreement, itemized in Exhibit A to the Settlement Agreement and further described above, shall be applied for ASR filing purposes for each year of the ARP. Specifically, to be included in the ASR are the Stock Based Compensation adjustment (line 11) and the Miscellaneous Adjustments (line 15). The Stock Based Compensation adjustment would be reported as the actualized amount and the Miscellaneous Adjustments would be reported as the amount agreed to in the Settlement Agreement of $14,175,000.

Q. DID GEORGIA POWER REMOVE STOCK-BASED COMPENSATION EXPENSE FROM ITS ANNUAL SURVEILLANCE REPORTS IN 2020 AND 2021?

A. No. Georgia Power did not remove stock-based compensation from its Annual Surveillance Reports in 2020 and 2021.

Q. WHAT WAS THE REASON FOR GEORGIA POWER NOT REMOVING STOCK-BASED COMPENSATION EXPENSE FROM ITS ANNUAL SURVEILLANCE REPORTS IN 2020 AND 2021?

A. The 2019 base rate case settlement in Docket No. 42516 that was approved by the Commission provided for the inclusion of stock-based compensation within retail cost of service under the 3-year alternate plan. However, Staff was not a party to the Company's 2019 rate case settlement, and in fact had recommended the removal of the costs of stock-based compensation from retail cost of service in Docket No. 42516. In its post-hearing brief in Docket No. 42516, Staff stated that the Company incurs the costs of stock-based compensation in an effort to improve Southern Company's financial performance for the benefit of shareholders rather than for the benefit of ratepayers. Specifically, Staff stated:

For instance, the purpose of these incentives is not to improve customer service or meet other regulated utility service requirements. To the contrary, the objectives of maximizing shareholder value on the one hand and minimizing costs to ratepayers on the other hand, are generally opposed to each other. And the fact that maximizing shareholder value frequently does not serve the ratepayer interest of lower rates for the service shows the fatal flaw in the argument that these financial incentives should be seen as merely part of a compensation package, and as such, should be recovered from ratepayers.

Q. WHAT DOES STAFF RECOMMEND IN THE CURRENT GEORGIA POWER RATE CASE?

A. As is explained below, Staff recommends that the PSU expense and the RSU expense be removed from retail jurisdictional operating expenses for purposes of establishing the Company's revenue requirement in the current rate case. As a matter of regulatory principle, ratepayers should not be required to pay executive or management compensation that is based on the performance of Southern Company's stock price, or which has the primary purpose of benefitting shareholders and/or to align the interests of participants in the stock-based compensation plans with those of such shareholders.

Q. SHOULD THE COMMISSION INCLUDE THE PSU AND RSU EXPENSE IN THE REVENUE REQUIREMENT?

A. No. The stock-based incentive compensation expenses for these programs should not be included in the revenue requirement. The cost of these incentive compensation programs is incurred to improve the Southern Company financial performance for the benefit of shareholders, not to improve customer service or meet other regulated utility service requirements. In fact, the objectives of maximizing shareholder value on the one hand and minimizing costs to ratepayers on the other hand, are generally opposed to each

other. In addition, the hypothetical stock performance pursuant to the PSU should not be considered expense for ratemaking purposes because dividends are considered in the determination of the required return on common equity and stock performance is a component of shareholder return.

Q. HAVE YOU QUANTIFIED THE EFFECT OF YOUR RECOMMENDATIONS TO DISALLOW THE STOCK-BASED INCENTIVE COMPENSATION EXPENSE FOR THE PSU AND RSU?

A. Yes. The effect is to reduce Georgia Power's forecasted test year retail operating expenses by $29.172 million. This quantification includes the costs directly incurred by the Company of $10.922 million and the affiliate charges of $13.033million from SCS and $5.217 million from SNOC for these stock-based compensation programs. The quantifications and the source of the data that we relied on for these quantifications are detailed on Exhibit__(RS/RT-2), Schedule E-4.

In addition, as it relates to the Company's alternative rate plan, the effect of removing the expense for the PSU and RSU is to reduce retail operating expenses by $29.063 million, $26.933 million, and $28.230 million for calendar years 2023, 2024 and 2025, respectively. Of these amounts, $10.666 million, $9.641 million and $10.251 million reflect costs directly incurred by Georgia Power. Likewise, $13.096 million, $12.206 million and $12.553 million reflect affiliate charges from SCS and $5.301 million, $5.085 million and $5.425 million reflect affiliate charges from SNOC.

Q. PLEASE EXPLAIN THE ADJUSTMENT CALCULATION SHOWN ON EXHIBIT__(RS/RT-2), SCHEDULE E-4.

A. Exhibit__(RS/RT-2), Schedule E-4 has four pages, one for the test year and one for each plan year, showing the adjustment amounts. The total amounts, O&M expense ratio and O&M expense for the PSU and the RSU are from (or were derived from) the Company's responses to STF-LA-2-78, STF-LA-2-79 and STF-LA-2-81 as shown in columns B, C, and D, respectively. For the test year, as shown on Exhibit__(RS/RT-2), Schedule E-4, page 1, line 11, the total adjustment reduces retail operating expense by $29.172 million. Pages 2, 3 and 4 of Schedule E-4 present similar information for plan years, 2023, 2024 and 2025, respectively.

Performance Pay Plan

Q. HAS THE COMPANY INCLUDED AMOUNTS RELATED TO ITS PERFORMANCE PAY PLAN IN THE CALCULATION OF ITS REVENUE REQUIREMENT IN THE FORECASTED TEST YEAR ENDING JULY 31, 2023 AS WELL AS FORECASTED CALENDAR YEARS 2023, 2024 AND 2025?

A. Yes. The Company has included amounts related to its Performance Pay Plan ("PPP") in the calculation of its revenue requirement for the forecasted test year ending July 31, 2023 as well as forecasted calendar years 2023, 2024 and 2025. Specifically, the table below summarizes the amounts of PPP expense included in Georgia Power's retail operating expense for the forecasted test year ending July 31, 2023 as well as the forecasted calendar years 2023, 2024 and 2025:

Description	7/31/2023 ($000's)	2023 ($000's)	2024 ($000's)	2025 ($000's)
GPC Directly Incurred PPP Expense Charged to O&M	$ 50,029	$ 51,033	$ 53,204	$ 55,395
SCS PPP Expense Allocated to GPC Charged to O&M	$ 30,874	$ 31,506	$ 32,421	$ 33,561
SNOC PPP Expense Allocated to GPC Charged to O&M	$ 34,433	$ 36,632	$ 38,042	$ 39,330
Total PPP Expense Charged to O&M	$ 115,336	$ 119,171	$ 123,667	$ 128,286
Source: STF-LA-2-81				

As shown in the table above, for the forecasted test year ending July 31, 2023, the Company's revenue requirement includes directly incurred PPP expense in O&M totaling $115.336 million. Of this amount, $50.029 million reflects directly incurred PPP expense, $30.874 million reflects PPP expense allocated from SCS and $34.433 million reflects PPP expense allocated from SNOC.

For forecasted calendar year 2023, the Company's revenue requirement includes directly incurred PPP expense in O&M totaling $119.171 million. Of this amount, $51.033 million reflects directly incurred PPP expense, $31.506 million reflects PPP expense allocated from SCS and $36.632 million reflects PPP expense allocated from SNOC.

For forecasted calendar year 2024, the Company's revenue requirement includes directly incurred PPP expense in O&M totaling $123.667 million. Of this amount, $53.204 million reflects directly incurred PPP expense, $32.421 million reflects PPP expense allocated from SCS and $38.042 million reflects PPP expense allocated from SNOC.

For forecasted calendar year 2025, the Company's revenue requirement includes directly incurred PPP expense in O&M totaling $128.286 million. Of this amount, $55.395

million reflects directly incurred PPP expense, $33.561 million reflects PPP expense allocated from SCS and $39.330 million reflects PPP expense allocated from SNOC.

Q. HOW WAS THE PPP INCENTIVE COMPENSATION EXPENSE ADDRESSED IN THE COMPANY'S PREVIOUS RATE CASES?

A. In Georgia Power's 2007 rate case, Docket No. 25060, Staff had recommended that Georgia Power's PPP be reduced to reflect a 100 percent payout, rather than the payout target in excess of 100 percent that Georgia Power had included in the cost of service. The Company's PPP expense was addressed in the base rate proceeding by including the amount proposed by Georgia Power in the cost of service in a settlement. In Georgia Power's 2010 rate case, Docket No. 31958, consistent with the ultimate treatment from Docket No. 25060, Staff accepted the amount proposed for PPP by Georgia Power and did not make an adjustment. Similarly, in Georgia Power's 2013 and 2019 rate cases, (Docket Nos. 36989 and 42516), consistent with the treatment in previous rate cases, Staff accepted the amount proposed for PPP by Georgia Power and did not make an adjustment.

Q. IS ANOTHER WITNESS FOR STAFF RECOMMENDING AN ADJUSTMENT TO REDUCE THE PPP INCENTIVE COMPENSATION EXPENSE IN THE COMPANY'S CURRENT RATE CASE?

A. Yes. As discussed in detail in his Direct Testimony, Staff witness Dante Mugrace is recommending an adjustment to remove a portion of the PPP incentive compensation expense from O&M expense in the current proceeding.

XIII. RATE PLAN PRINCIPLES AND RECOMMENDATIONS

Multi-Year Rate Plans Versus Traditional Test Year Based Ratemaking

Q. HOW IS AN ALTERNATIVE RATE PLAN DIFFERENT FROM A TRADITIONAL RATE CASE ORDER IN TERMS OF EARNINGS ABOVE THE ROE BAND?

A. Under a traditional rate case order, the Company could earn in excess of an authorized ROE without the ratepayers receiving any rate reductions or any benefit from the application of earnings above the top of the rate band. While the Commission would have the authority to bring the Company in under a Rule Nisi proceeding to reduce its rates, such a proceeding would take a significant amount of time and any order reducing rates would be prospective in nature.

Q. HOW IS THE ALTERNATIVE RATE PLAN DIFFERENT FROM A TRADITIONAL RATE CASE ORDER IN TERMS OF EARNINGS BELOW THE AUTHORIZED ROE OR LOWER ROE BAND?

A. Under a traditional rate case order, the Company could earn less than the authorized ROE and would not have any recourse except to file a rate case. Any relief would be prospective in nature.

Q. HOW DOES TRADITIONAL RATEMAKING COMPARE WITH A MULTI-YEAR RATE PLAN IN TERMS OF WHEN THE COMPANY FILES RATE CASES?

A. Under a traditional rate case order, the Company would be able to file another rate case whenever it deemed appropriate, and the Commission would have the ability to bring

Georgia Power in for a Rule Nisi to address any overearnings. Some such costs, such as projected increased costs for 2024 and 2025, did not fall within the test year period for this docket, and those costs could have fallen within the test year period of a subsequent rate case filing.

Q. HOW CAN A MULTI-YEAR RATE PLAN PROVIDE FOR RATE STABILITY?

A. The accounting order/rate plan can provide ratepayers with rate stability and certain benefits depending on how it is structured. Unless the Company's earnings are projected to drop below the bottom of the earnings band, the Staff proposed alternative rate plan for the current case (similar to previous rate plans) would prohibit Georgia Power from filing for a rate increase until a date provided for in the rate plan. However, the Company would have the option to petition the Commission to increase rates up to lower band if its projected earnings would fall below the lower band. Also, the plan may include step increases which increase rates rather than stabilizing rates. While there are certain advantages in step increases there are tradeoffs including only considering certain cost that are increasing rather than all cost which may include some cost that are decreasing. If a three-year rate plan were to be approved, the Company would be prohibited from increasing rates (other than the two step increases) prior to January 1, 2026, unless it were projected to earn below the bottom end of the allowed earnings band.

Q. IS HAVING A THREE-YEAR RATE PLAN A BENEFIT TO THE COMPANY?

A. Yes. Having a rate plan that is approved by the Commission and agreed to by the Company benefits the Company. One benefit is that the first-year revenue requirement

could be based on calendar year 2023, rather than upon the statutory test year ending July 31, 2023. The Company's filing shows a traditional base rate revenue deficiency of approximately $312.2 million based on the July 31, 2023 test year,[34] and a base rate revenue deficiency of approximately $431.4 million[35] for calendar year 2023 as well as revenue deficiencies of $718.0 million and $1.080 billion for 2024 and 2025.[36] Thus, the time shifting of the revenue requirement basis for the first year of new rates has a monetary benefit to the Company.[37]

Earnings Test and Earnings Band-History

Q. HAVE YOU PREPARED A TABLE SUMMARIZING HOW THE EARNINGS SHARING HAS WORKED FOR RATEPAYERS AND THE COMPANY OVER THE PAST SEVERAL YEARS?

A. Yes. This is summarized in the following table for 2007 through 2021, based on ASR results:

[34] See, e.g., Exhibit__(APA/SPA/ADH/MBR-1 Schedule 2 Traditional Base), page 3 of 3, column (3) line 4.

[35] Id. At column (4), line 4.

[36] Id. At columns (5) and (6), line 4.

[37] Presumably, the time shifting benefit is not limited to the first year. If the Company filed additional traditional cases effective for 2024 and 2025, the test years for those cases would similarly lag the calendar year test years that a 3-year plan would allow.

Georgia Power Company Historical Earnings Sharing Based on Annual Surveillance Reports

Year	ROE Reported in ASR Filing	Lower End of Earnings Band	Upper End of Earnings Band	Adjusted ROE	ROE Above Upper End of Earnings Band	ROE used to Set Revenue Requirement in Rate Case	Adjusted ROE Above ROE used to Set Revenue Requirement	Accounting Adjustment Related to Preventing Under-Earnings		Earnings Above Top End of Band ($ millions)	Amount Refunded to Customers ($ millions)	Stewart County Regulatory Asset	CCR ARO Regulatory Asset	Amount of Excess Earnings Retained by Company ($ millions)
2007	11.36%	10.25%	12.25%	11.52%	N/A	11.25%	0.27%							
2008	12.11%	10.25%	12.25%	12.20%	N/A	11.25%	0.95%							
2009	9.75%	10.25%	12.25%	9.75%	N/A	11.25%		$ 1.46	[a]					
2010	10.15%	10.25%	12.25%	10.15%	N/A	11.25%		$ 3.30	[a]					
2011	11.72%	10.25%	12.25%	11.72%	N/A	11.15%	0.57%							
2012	11.99%	10.25%	12.25%	11.99%	N/A	11.15%	0.84%							
2013	11.43%	10.25%	12.25%	11.44%	N/A	11.15%	0.29%							
2014	12.12%	10.00%	12.00%	12.14%	0.14%	10.95%	1.19%			$ 16.96	$ 11.31			$ 5.65
2015	11.52%	10.00%	12.00%	11.55%	N/A	10.95%	0.60%							
2016	12.46%	10.00%	12.00%	12.49%	0.49%	10.95%	1.54%			$ 65.40	$ 43.60			$ 21.80
2017	11.91%	10.00%	12.00%	12.04%	0.04%	10.95%	1.09%			$ 3.55	$ 2.37			$ 1.18
2018	13.17%	10.00%	12.00%	13.18%	1.18%	10.95%	2.23%			$ 153.10	$ 102.07			$ 51.03
2019	12.88%	10.00%	12.00%	12.88%	0.88%	10.95%	1.93%			$ 123.24	$ 61.62	$ 48.79	$ 12.83	$ -
2020	11.89%	9.50%	12.00%	11.89%	N/A	10.50%	1.39%			$ -	$ -			$ -
2021	12.09%	9.50%	12.00%	12.09%	0.09%	10.50%	1.59%			$ 14.17	$ 5.67		$ 5.67	$ 2.83
									Totals	$ 376.41	$ 226.62	$ 48.79	$ 18.50	$ 82.50
									Percent of Totals	100.00%	60.21%	12.96%	4.91%	21.92%

Notes

[a] $2.2 and $0.972 million restored to the accrued removal cost regulatory liability account in 2010 and 2009, respectively, based on Staff's recommended adjustments.

The Commission's Short Order Adopting Settlement Agreement beginning January 1, 2020, expended the earnings band to 9.5% lower/12% upper. It also changed the sharing percentage to reflect 40% to customers, 40% to regulatory assets, and 20% to the Company.

In 2019, the Company did not retain a portion of the dead band overage. It was used to reduce the Stewart County regulatory asset and to reduce the CCR ARO regulatory asset account

As shown in the above table, the Company has consistently earned well above its authorized ROE in every year except during the Great Recession in 2009 and 2010. In the 2014-2021 period, the Company has reported about $376.4 million of revenues representing earnings above the top end of the ROE band. Over 60 percent of that, or approximately $226.6 million was for refunds to ratepayers, 13 percent, or approximately $48.9 million was allocated to the Stewart County regulatory asset, five percent, or approximately $18.5 million, was allocated to the CCR ARO regulatory asset, while the Company retained the remaining 22 percent, or approximately $82.5 million.

Staff Rate Plan Recommendations

Q. HAVE YOU PREPARED A SUMMARY OF STAFF'S RECOMMENDED 2023, 2024 AND 2025 PLAN YEAR REVENUE DEFICIENCY (OR EXCESS) AMOUNTS?

A. Yes. The following table shows Staff's recommended 2023, 2024 and 2025 plan year revenue deficiency (or excess) amounts.

Staff Calculated Revenue Requirement Deficiency/(Excess) by Year (Millions of Dollars)					
	Exhibit_(RS/RT-2)				
Effective Date	Schedule A Reference	1/1/2023	1/1/2024	1/1/2025	Total
Traditional Base Rates Revenue Deficiency/(Excess)	Line 10	$ (109)	$ (2)	$ 199	$ 88
ECCR Revenue Deficiency	Line 8	$ 61	$ 91	$ 127	$ 279
DSM Revenue Deficiency	Line 9	$ 37	$ 64	$ 62	$ 163
Total Deficiency/(Excess)		$ (11)	$ 153	$ 388	$ 529

Q. IS STAFF RECOMMENDING THE RATE INCREASES AND DECREASES SHOWN IN THE ABOVE-TABLE?

A. No. As shown on Exhibit __(RS/RT-2), Schedule A, on lines 7 and 12, Staff shows revenue excesses for the test year and 2023. Staff is recommending no change for 2023 and that the Company be required to file compliance filings on October 1, 2023 and October 1, 2024 for the step increases to become effective on January 1, 2024 and January 1, 2025, respectively.

Q. PLEASE EXPLAIN STAFF'S RATE PLAN RECOMMENDATIONS.

A. As described above in our testimony, Staff recommends that revenue changes for January 1, 2024 and 2025 for base rates as well as the ECCR rates be applied as step adjustments, rather than charged on a levelized basis to retail ratepayers beginning on January 1, 2023. Staff also recommends that the Company continue to update its estimated costs for ECCR and for CCR ARO Compliance cost recovery, and that the Company file by October 1, of 2023 and 2024, respectively, for ECCR and CCR ARO revenue requirements for 2024 and 2025, respectively.

Staff also recommends that an earnings test be applied, with an ROE band of 200 basis points centered around Staff's recommended 9.45% ROE, as described below.[38]

Staff further recommends that earnings above the top end of the earnings band be applied for the accelerated recovery of deferred costs and regulatory assets, rather than the two-thirds/one-third sharing which had been incorporated in some prior rate plans.[39]

Step Increase Approach

Q. DOES STAFF RECOMMEND A STEP-APPROACH FOR THE 2024 AND 2025 INCREASED REVENUE REQUIREMENTS?

A. Yes. Staff believes that a step-approach involving interim filings during the 2023-2025 three-year plan period would be far preferable to approving a levelized revenue requirement under the circumstances present in the current Georgia Power rate case. The Commission has employed step increases effectively in the context of three-year plans, including for the Company's recovery additional revenue requirements associated with Plant McDonough Units 4 and 5 in compliance with the Commission's 2010 Rate Case Order in Docket No. 31958.

[38] 200 basis point bands centered around a midpoint ROE have previously been used by the Commission in Dockets 25060 and 18300.

[39] For example, in Docket 25060 one-third was used to pay down the ECCR and two-thirds went to rate reductions. In 42516, the Company sharing was limited to 20%.

Q. WHAT ARE THE REASONS FOR RECOMMENDING A STEP INCREASE APPROACH, RATHER THAN A LEVELIZED APPROACH TO THE THREE-YEAR RATE PLAN?

A. First, customers should not be required to pay for 2024 and 2025 revenue requirements starting January 1, 2023, i.e., before the related costs have been incurred, especially during a period when the economy could be entering into a recession. Also, the Company has projected that Plant Vogtle Unit 3 will be in commercial operation by March 2023 and Unit 4 by December 2023. Currently, the Company is collecting from ratepayers portions of the financing cost for those units while they are under construction. The Company continues to incur construction costs and AFUDC. While those dates might be delayed, the Vogtle Unit 3 and 4 rate impacts, once more fully recognized, are anticipated to be substantial.[40]

Furthermore, Staff has concerns about some of the large items in the 2024 and 2025 revenue requirements. Under a levelized approach, ratepayers would incur the costs related to these items beginning January 1, 2023. These items include recognition of cost increases that are occurring in 2024 and 2025 beyond levels projected for 2023. These concerns, coupled with the uncertainties about the timing of cost incurrence, warrant a cautious approach to determining appropriate revenue requirements for the Company for the 2024 and 2025 plan years.

[40] Plant Vogtle Units 3&4 being placed into commercial operation could increase base rate revenue requirements by approximately $1 billion per year assuming no additional delays or cost overruns or Commission disallowances. This would be offset by approximately $200 million per year from termination of the Nuclear Construction Cost Recovery tariff.

Q. PLEASE EXPLAIN ANY POTENTIAL IMPACT ON ENVIRONMENTAL COSTS PROJECTED FOR 2024 AND 2025 FROM ANY CHANGES TO THE RULES AND/OR COMPLIANCE DATES.

A. The timing and level of certain environmental costs, such as plant retirements and environmental retrofits that have been addressed in the 2022 IRP, could be affected if any revisions are made to environmental regulations, including the compliance date.

Q. ALTHOUGH THE COMPANY HAS INDICATED THAT IT WOULD PREFER A LEVELIZED THREE-YEAR RATE PLAN, DID THE COMPANY ACKNOWLEDGE THAT A STEP-INCREASE APPROACH COULD BE USED FOR THE INCREASED REVENUE REQUIREMENTS FOR 2024 AND 2025?

A. Yes. During the hearings on Georgia Power's direct case, the Company acknowledged that estimates can become less reliable the further out into the future they extend. (Tr. 292.) Using a Step-Increase will more accurately reflect the revenue requirement for each year. Moreover, while the Company would prefer its proposed levelized approach, it acknowledged that an alternative would be to step-up the increases over the three-year period covered by the projected test years for 2023, 2024 and 2025. (Tr. 292).

Q. HAS THE COMMISSION PREVIOUSLY DIRECTED THE COMPANY TO FILE INTERIM RATES THAT WOULD BECOME EFFECTIVE DURING THE TERM OF A THREE-YEAR ACCOUNTING ORDER?

A. Yes. For example, as provided for in the approved stipulation and Commission Order in Docket No. 31958, the Company filed to increase rates effective in 2012 and 2013. On

November 1, 2011, the Company filed updated Demand Side Management (DSM) Residential and Commercial tariffs for approval. These tariffs were approved by the Commission, allowing the Company to collect its updated DSM revenue requirement. At the same time, the Company also updated its Nuclear Construction Cost Recovery (NCCR) tariff to collect $258.6 million for projected 2012 financing costs associated with Plant Vogtle Units 3 and 4. The effective date of those tariff updates was January 1, 2012.

Q. THE COMPANY IS REQUESTING $2.9 BILLION IN ADDITIONAL REVENUES FOR THE THREE YEAR PERIOD 2023 – 2025 IN THIS PROCEEDING. WHAT SHOULD THE COMMISSION CONSIDER WHEN EVALUATING THE COMPANY'S REQUEST?

A. The Company's proposed base rate increase is the first of four increases customers will be subject to during 2023 and 2024. The other three increases are Vogtle Unit 3 being placed in service in 2023, fuel rate increase in 2023, and Vogtle Unit 4 being placed in service in 2024. Staff has estimated the total impact on a typical residential customer of the Company's requests could be in the range of $55 to $60 per month or approximately 45 percent increase. Some of the increases are for cost recovery of items such as fuel that are mandatory. Other increases are for recovery of capital investment proposed in this rate case that is discretionary. The Commission may want to closely scrutinize the discretionary costs in this proceeding so to mitigate the cumulative impact of the four increases in customer bills in the 2023 through 2025 rate plan period.

Q. IN PAST DOCKETS THE COMMISSION HAS APPROVED ANNUAL STEP INCREASES BETWEEN BASE RATE CASES. WHAT SHOULD THE COMMISSION TAKE INTO ACCOUNT IF IT APPROVES ANNUAL STEP INCREASES UNDER A THREE YEAR ANNUAL ACCOUNTING PLAN IN THIS PROCEEDING?

A. The Company is proposing a very large increase in rate base over the three period 2023 – 2025 tied to large annual capital investment. Given the Company's history with capital projects, some the capital investment may not be placed in rate base as the Company has forecast. If the Company were to overestimate how quickly capital projects would be completed, the Company's rate base would also be overestimated. This would result in rates substantially higher than necessary to allow the Company an opportunity to earn a fair return. Staff recommends the Company provide actual detailed retail rate base as of September 30 of each year and revised detailed projected retail rate base for upcoming year(s) in step increase filings.

Application of Earnings Above Top End of Band

Q. PLEASE ADDRESS THE STAFF'S RECOMMENDATION CONCERNING EARNINGS SHARING WITHIN THE AUTHORIZED EARNINGS BAND.

A. As part of the alternative rate plan, Staff recommends that an earnings sharing mechanism should continue to apply, but with certain modifications/improvements from how it has been applied under the Stipulation in Georgia Power's last rate case. While Georgia Power's earnings band in the past has been a 200 basis point range in its last three rate cases, Staff recommends narrowing of the earnings band. For purposes of this

plan Staff recommends a band of 8.45% to 10.45% which would allow the Company to retain all revenues up to 1.0% above Staff's recommended authorized ROE.

Q. HOW DOES STAFF RECOMMEND THAT EARNINGS ABOVE THE TOP END OF THE BAND BE APPLIED?

A. As noted above, Staff proposes an ROE band of 8.45% to 10.45% above which is 100 basis points below and above the 9.45% ROE recommended by Staff witness Gorman. Any earnings above the band should be used to pay down Georgia Power's regulatory assets. This band is symmetrical in terms thresholds unlike the previous band of 9.5% to 12.0% with a set point of 10.5%. This band strikes a more equitable balance between the ratepayers and the Company. The consequences of breaching the band under Staff's proposal would also be more equitable. The lower band effectively places a floor underneath the Company's earnings – guaranteeing the Company a minimum return. It is only fair that all earnings that exceed the upper band be retained to the benefit of customers.

XIV. SUMMARY OF STAFF RECOMMENATIONS

Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATIONS.

A. Staff shows a revenue excess for the test year ending July 31, 2023 and for calendar year 2023. Staff recommends no traditional base rate change for January 1, 2023. Staff recommends that the Company file compliance filings on October 1, 2023 for a January 1, 2024 step increase and on October 1, 2024 for a January 1, 2025 step increase.

Staff has made the following recommendations:

1. Accept the adjustments identified by the Company in its supplemental filing.
2. Accept the adjustments described in our testimony for the test year and each plan year for calculating the revenue requirement excess or deficiency (or excess) for traditional base rates (as shown in Exhibit __RS/RT-2), for the ECCR (as shown in Exhibit __RS/RT-3), for DSM (as shown in Exhibit __RS/RT-4), for Municipal Franchise Fees (as shown in Exhibit __RS/RT-5), and for CCR ARO Compliance (as shown in Exhibit __RS/RT-6).
3. The traditional revenue requirement for Georgia Power in this rate case should be determined based on the use of the Commission-ordered test year ending July 31, 2023.
4. The appropriate traditional test year average retail rate base is $24.039 billion which is $21.265 million higher than the Company's proposed traditional test year average retail rate base of $24.018 billion.

5. The appropriate traditional test year retail operating income is $1.709 billion, which is $193.069 million higher than the Company's proposed test year traditional test year retail operating income of $1.516 billion.
6. The appropriate traditional test year overall rate of return for Georgia Power in this case that Staff used 6.84% and includes a fair return on equity of 9.45% and the capital structure as recommended by Staff witness Michael Gorman.
7. The appropriate income expansion factor to be used for ratemaking purposes in the test year in this case is 74.606% and 74.602%, 74.596% and 74.593% for 2023, 2024 and 2025, respectively.
8. That rates be set using the traditional test year ratemaking components.
9. That the Company's proposed 2023-2025 levelization revenue requirement adjustment of $426.4 million to derive a levelized revenue deficiency amount of $738.7 million per year for 2023-2025 (not including CCR ARO Compliance) not be adopted. Rather, Staff recommends that a step-increase approach be used if a three-year rate plan is adopted.
10. That current rates be maintained through 2023.
11. That the revenue excess in 2023 be used for accelerated recognition of deferred costs in 2023 up to the amount of the revenue excess.
12. Continuation of the existing DSM tariff rider, reflecting Staff's carrying cost rates and Staff's recommended cost of capital.
13. Prior to requesting ECCR cost recovery each year, the Company should refine the estimate as much as possible.

14. That the Commission not pre-approve a level of ECCR cost recovery for years 2024 and 2025 in the current rate case, but rather that the Company making an annual compliance filing to update the ECCR spending and estimates each year on October 1 of the preceding year for ECCR rates to become effective the following January 1.
15. That the Commission not pre-approve a level of CCR ARO cost recovery for years 2024 and 2025 in the current rate case, but rather that the Company making an annual compliance filing to update the CCR ARO spending and estimates each year on October 1 of the preceding year for CCR ARO rates to become effective the following January 1.
16. Prior to requesting CCR ARO cost recovery each year, the Company should refine the estimate as much as possible.

For the rate plan, Staff also recommends:

- an earnings band of 8.45% to 10.45%, i.e., extending 100 basis points below and above Staff's recommended ROE of 9.45%.
- application of earnings above the 10.45% top end of Staff's recommended earnings band to the recovery of Company deferred costs and regulatory assets.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.