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December 8, 2022

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334-5701

Re: Georgia Power Company's 2022 Rate Case, Docket No. 44280

Dear Ms. Tanner:

Enclosed for filing is the Post Hearing Brief and the Proposed Order of Georgia Power Company.

If you have any questions, please call me at 404-885-3683.

Sincerely,

Brandon F. Marzo

Enclosure

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
Georgia Power Company's	)	**Docket No. 44280**
2022 Rate Case	)	
	)	

POST HEARING BRIEF OF GEORGIA POWER COMPANY

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Dated: December 8, 2022

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2022 Rate Case	)	
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POST HEARING BRIEF OF GEORGIA POWER COMPANY

I. INTRODUCTION

Georgia Power Company ("Georgia Power" or the "Company") submits this brief in support of its proposed Alternate Rate Plan ("ARP") as amended by the Company's August 22, 2022 Supplemental Filing, September 28, 2022 Errata, and November 21, 2022 Errata filed in this proceeding. The Company's 2022 Rate Case was filed pursuant to the terms and conditions of the Georgia Public Service Commission's (the "Commission") February 6, 2020 Order Adopting Settlement Agreement in Georgia Power's 2019 Rate Case in Docket No. 42516 ("2019 Rate Case Final Order"). As explained herein, based on the evidence before it, the Commission should approve the Company's application for a rate increase.

II. SUMMARY OF THE ARGUMENT

Georgia Power recommends that the Commission maintain the constructive regulatory environment, effectuated through the Company's ARP, that has benefitted Georgia Power's customers for decades. This Commission's constructive regulatory policies have created a sustained period of high customer satisfaction, high reliability, and rates below the national average, and have contributed to Georgia consistently being ranked as the best state in the nation in which to do business. This Commission has a well-deserved national reputation for maintaining a consistent and balanced regulatory environment that benefits all stakeholders.

Many of the recommendations and positions taken by the Commission's Public Interest Advocacy ("PIA") Staff and Intervenors appear to ignore what has changed over the past three

years, as well as what has remained constant since the 2019 rate case order. Changes over the past three years include: (1) the emergence of a global pandemic; (2) rampant and rapid inflation that has increased costs for businesses and consumers alike; (3) growing pressure on supply chain and labor markets; (4) significant increases in the federal funds rate and cost of borrowing; and (5) evolving customer needs, demands and requests for increased distributed energy resources and carbon-free energy. Notwithstanding these changes, several things have remained constant: (a) this Commission's continued constructive and balanced approach that ensures customers continue to receive clean, safe, reliable, and affordable electricity, even during a global pandemic; (b) the importance of financial integrity and credit quality, which is never more evident than during times of global uncertainty and financial market volatility, such as that being experienced today; (c) customers remain at the center of everything the Company does, as evidenced by Georgia Power's continued excellent customer service and reliability performance with rates below the national average; and (d) that the state of Georgia continues to be ranked as one of the best places for business, with Georgia's economy continuing to grow and with economic development reaching all-time highs.

When considering the past three years, many of the recommendations made by parties in this case would harm customers by upsetting the well-designed and balanced regulatory structure currently in place, and ultimately undermine the financial health and integrity of Georgia Power. These recommendations are unacceptable to the Company.

PIA Staff and Intervenors have also proposed modifications to the ARP that are fundamentally inconsistent with the concept of an ARP that incentivizes the Company to innovate and achieve operational efficiencies that benefit customers. Therefore, Georgia Power does not support the recommendations to narrow the earnings band, set the top end of the earnings band at an artificially low level, or eliminate the sharing mechanism for earnings above the top end of the band. The recommended alterations to the Company's proposed authorized earnings band would remove revenue sharing incentives and effectively create an earnings cap, potential rate instability, and be counterproductive to the goal of incentivizing the Company to drive efficiencies in the business for the benefit of customers. In addition, the recommendations by Staff and other intervenors to revise the content and estimates supporting the Company's annual compliance

filings edges ever closer to having abbreviated rate cases every year, which encourages less predictability in rates.

The Company opposes the return on equity ("ROE") setpoint and capital structure recommendations put forth by PIA Staff and several Intervenors. If adopted, PIA Staff's recommended 105 basis point ROE reduction from the Company's current setpoint would represent the largest single ROE reduction for Georgia Power in decades. Many of these same parties also propose to reduce the equity portion of the Company's capital structure, the most drastic of which would reduce the Company's equity ratio from 56% to 51% in the second and third years of the ARP. The Company's current capital structure was approved by this Commission in response to the 2017 Tax Cut and Jobs Act ("TCJA") and modified in the Company's last rate case. Passage of the TCJA was the impetus for the initial increase in equity several years ago, and the impact of the TCJA remains unchanged. With this in mind, PIA Staff's suggested 500-basis point equity ratio reduction from the current Commission-approved 56% based on the anticipated completion of Plant Vogtle Units 3 and 4 has no merit. Such severe changes to the Company's ROE and capital structure would significantly impair the Company's financial integrity and its ability to raise capital at reasonable cost and upon reasonable terms for the benefit of customers. In contrast, the ARP, together with the Company's proposed 11.00% ROE and 56% equity level, will support the Company's financial integrity and ensure the Company continues to access capital markets at reasonable rates and on reasonable terms. At these levels, the Company's Funds from Operations ("FFO") to Debt ratio, a key metric used by the ratings agencies to analyze a company's financial risk, will meet the thresholds identified by the credit rating agencies as necessary to maintain the Company's current credit quality.

PIA Staff wrongly asserts that the Company can arbitrarily reduce its Operations and Maintenance ("O&M") expense based on the past three years, as if major outage or maintenance work occurs at the same level every year and based on the erroneous assumption that operating through the recent pandemic was indicative of Georgia Power's cost to serve customers during a normal operating environment. The Company's O&M requests in this case were thoughtfully designed to support the next three years of critical function and operation of Georgia Power to ensure that the Company can continue to provide clean, safe, reliable, and affordable electric service with exceptional customer service.

PIA Staff has also proposed to substantially reduce or eliminate transmission and distribution investments within the Grid Investment Plan, which are required to support the long-term reliability and resiliency of our electric system, seemingly without considering the long-term adverse impacts such reductions would cause to the electric system. The Company cannot delay or take shortcuts in implementing these grid investments as they are necessary to address aging transmission infrastructure and improve reliability performance for nearly 1.4 million customers throughout the state who are served by lower performing feeders.

In the aggregate, the modifications proposed by PIA Staff and several Intervenors undercut core aspects of the ARP and are unacceptable. The Company cannot agree to an ARP that would impair its financial integrity, threaten its current credit ratings, fundamentally alter the framework of the ARP and strip it of its core benefits, or jeopardize the Company's ability to provide customers with safe and reliable electric service. The Commission should approve the Company's proposed ARP, without modification, as a fair and reasonable resolution of this proceeding that appropriately balances the interests of customers, the Company, and investors. Approval of the Company's three-year ARP will continue the Commission's long-standing tradition of constructive regulation and provide stability and certainty for customers and the Company.

The Company understands this Commission must consider the cost of electric service when evaluating Georgia Power's cost to serve its 2.7 million customers. Georgia Power has thoughtfully and appropriately balanced the request in this proceeding with both the financial impacts to, and needs of, our customers. Georgia Power operates a capital-intensive business and has the privilege and obligation to serve its customers in this rapidly changing world. Adopting the Company's proposed ARP will ensure the Company remains financially healthy and able to provide clean, safe, reliable, and affordable service to its customers now and into the future. Therefore, and for the reasons discussed further herein, the Commission should approve the Company's application to adjust rates as filed, including the Company's proposed ARP.

III. PROCEDURAL BACKGROUND

The Commission issued its Procedural and Scheduling Order for the Company's 2022 Rate Case on April 7, 2022, as subsequently amended by the July 26, 2022 Amended PSO, August 5, 2022 Second Amended PSO, and November 8, 2022 Third Amended PSO (collectively as

amended, the "PSO"). In accordance with the PSO, the Company's June 24, 2022 filing included the minimum filing requirements specified by Commission Rule 515-2-1-.04, along with the direct testimony and exhibits of Christopher C. Womack, the panel of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, James M. Coyne, Lee Evans, Steven M. Fetter, and Larry T. Legg. Hearings regarding the Company's direct case were held September 27, 2022, through September 29, 2022.

On October 20, 2022, the Commission's Public Interest Advocacy ("PIA") Staff filed the direct testimony and exhibits of the following witnesses: the panel of Ralph C. Smith and Robert L. Trokey; Michael P. Gorman; the panel of Jamie Barber, Benjamin Deitchman, and Glenn A. Watkins; the panel of Stephen J. Baron and Leah Wellborn; Rajendrasinh (Raj) Rana; Kevin O'Donnell; Lance Kaufman; the panel of Paul J. Alvarez and Dennis Stephens; and Dante Mugrace. Also on October 20, 2022, Americans for Affordable Clean Energy ("AACE") filed the direct testimony and exhibits of the panel consisting of Joseph Akers, Ron Nelson, and Barry Selvidge; ChargePoint, Inc., filed the direct testimony and exhibits of Justin D. Wilson; the Commercial Group filed the direct testimony and exhibits of Steve W. Chriss; EVgo Services, LLC, filed the direct testimony and exhibits of Colin Murchie; the Georgia Association of Manufacturers ("GAM") filed the direct testimony and exhibits of Jeffry Pollock, Billie S. LaConte, and Roger C. Tutterow, Ph.D; the Georgia Coalition of Local Governments ("Coalition"), filed the direct testimony and exhibits of C. Nicholas Deffley and David A. Nifong; Georgia Interfaith Power & Light ("GIPL") filed the direct testimony and exhibits of Mark E. Ellis and Justin Barnes; Georgia Solar Energy Industries Association ("GSEIA"), Solar Energy Industries Association ("SEIA"), and Vote Solar filed the direct testimony of Kevin Lucas and Thatcher Young; Metropolitan Atlanta Rapid Transit Authority ("MARTA") filed the direct testimony of Kevin Hurley; Southern Alliance for Clean Energy ("SACE") and Southface Energy Institute, Inc. ("Southface") filed the direct testimony of Ronald Lehr; the U.S. Department of Defense and all other Federal Executive Agencies ("DOD") filed the direct testimony and exhibits of Maureen L. Reno and Larry Blank; and United Management Services on behalf of RTC Investments filed the direct testimony and exhibits of Brian W. Coughlan (each an "Intervenor").

Also on October 20, 2022, and in accordance with the PSO, Georgia Power filed the supplemental direct testimony and exhibits of Dr. David Gattie and the panel of Lee Evans and

Larry Legg. Hearings regarding the direct testimony of PIA Staff and Intervenors were held on November 8, 2022, through November 10, 2022. Hearings regarding the Company's supplemental direct testimony were held on November 10, 2022.

On November 18, 2022, the Company filed the rebuttal testimony of the panel of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, James M. Coyne, Steven M. Fetter, and the panel of Lee Evans and Larry T. Legg in response to the positions advocated by PIA Staff and various Intervenors. Also on November 18, 2022, PIA Staff filed the supplemental direct testimony and exhibits of the panel of Jamie Barber, Timothy Cook, and Glenn A. Watkins; the Coalition filed the direct testimony David G. Hill, Ph.D.; GIPL filed supplement direct testimony of Justin Barnes; GA Solar filed the supplemental direct testimony of Kenneth Sercy; GSEIA, SEIA, and Vote Solar filed supplemental direct testimony and exhibits of the panel of Kevin Lucas, Thatcher Young, and Will Giese; and SACE and Southface filed the direct testimony and exhibits of Dr. Marilyn A. Brown and Alden M. Hathaway. On November 23, 2022, Georgia Power filed the supplemental rebuttal testimony of Lee Evans and Larry Legg. Hearings regarding the Company's rebuttal testimony, PIA Staff and Intervenor supplemental direct, and the Company's supplemental rebuttal testimony were held November 29, 2022 through 30, 2022.

IV. ARGUMENT

A. Approval of the Company's Application as Filed Will Continue the Constructive Regulatory Environment that Customers, the Commission, the Company, and Investors Rely Upon.

Approval of the Company's Application, including the Company's recommended ARP, supports the constructive regulation in Georgia that has benefitted customers for decades. The Company's filing in this case is consistent with the Commission's policies that have cultivated a sustained period of high customer satisfaction, high reliability, rates below the national average, and contributed to Georgia consistently being ranked as the best state in the nation in which to do business. The Commission's regulatory structure has created an environment in which: (i) the Company can provide the clean, safe, and reliable service that our customers depend on to meet their evolving energy needs; (ii) the Company can access capital on favorable terms to meet the current and future needs of our customers; and (iii) the Company's investors have an opportunity

to receive the returns appropriate for a well-run and efficient utility that meets the needs of its customers. This Commission's ability to balance strong and consistent policy while also adapting to rapidly evolving technology and implementing gradual changes when appropriate, has facilitated a consistent regulatory environment viewed favorably by customers and investors alike. Approval of the Company's filing will continue this trend.

The ARP filed by the Company satisfies the core responsibilities of the Commission as stated by the Supreme Court of Georgia:

> It is the responsibility of the commission to require a regulated utility to provide a level of service within its service area this year, next year, and in the foreseeable future; consonant with this responsibility the commission must approve utility rates that will produce enough revenue not only for operating expenses but also for the capital costs of the business. Capital for the business includes that required for current and future construction, and its costs include interest and dividends that must be paid to reasonably attract such capital.

Georgia Power Co. v. Georgia Public Service Commission, 231 Ga. 339, 344 (1973).

Given the Company's performance under the Commission's consistent regulation within the context of a global pandemic, rampant inflation, supply chain and labor market pressures, increasing cost of debt, and evolving customer needs, the modifications and changes proposed by PIA Staff and Intervenors are inappropriate and punitive. There is no support under Georgia law, the Commission's regulatory precedent, or the record in this proceeding, for the proposition implicit in PIA Staff and certain Intervenor's recommendations that rates should be set as low as possible according to calculations that clearly threaten the Company's ability to maintain, let alone improve, its credit metrics. Moreover, the parties advocating for these modifications disregard the impact their proposals would have on the Company's ability to access capital markets on reasonable terms and attract the substantial capital necessary to continue providing clean, safe, and reliable service at the industry-leading level of customer service that the Company's customers deserve and expect.

Rating agencies look for consistent application of sound economic regulatory principles by utility regulators. (*See* Tr. 795-96.) In fact, the most recent opinions from each of the three credit rating agencies reference their assessment that Georgia Power's multiyear rate plan has been

"supportive of GPC's credit quality,"[1] that "the overall regulatory framework in Georgia will remain credit supportive,"[2] and that they "expect a constructive resolution to Georgia Power's pending rate case filing, which proposes a three-year rate plan."[3] (Tr. 3949.) In contrast, if a regulatory body allowed a utility the opportunity to earn a fair return on utility assets and subsequently applied cost recovery principles in a manner inconsistent with the regulatory compact, investors' interest in providing funds to that utility would be altered, the utility's risk profile would deteriorate, and the utility's access to capital at reasonable terms would suffer – all to the detriment of customers. (*See* Tr. 794.)

The combined effect of the recommendations by PIA Staff and some Intervenors to alter the Company's ARP proposal would result in a negative reaction from investors and could lead to negative rating actions to the detriment of the Company and customers. (Tr. 3950, 3957, 4167, 4171, 4184.) The Company encourages this Commission to continue fostering regulatory consistency and avoid drastic action that could disturb the balance this Commission has created, which has been proven to benefit customers.

B. The Commission Should Adopt the Company's Proposed ROE, Cost of Capital, and Capital Structure, and Reject PIA Staff's ROE, Cost of Capital, and Capital Structure to Avoid Jeopardizing Georgia Power's Financial Integrity.

1. The Commission should adopt the Company's proposed capital structure and ROE as calculated by Mr. Coyne.

The Commission should adopt Mr. Coyne's 11% ROE recommendation and the Company's proposed 56% equity capital structure to ensure the Company can continue to access capital markets at reasonable rates and terms. Georgia Power proposes that its capital structure containing approximately 56% common equity and 44% debt be used for ratemaking purposes in this proceeding. (Tr. 72, 202, 631, 672.) Mr. Coyne analyzed the Discounted Cash Flow ("DCF") model, Capital Asset Pricing Model ("CAPM"), Bond Yield Risk Premium model, and the Expected Earnings models for a comparable utility group and estimated the cost of equity to run from 8.99% to 13.55%, with a four model average of 10.92%. (Tr. 631, 652, 667, 673.) Based on

1 S&P Summary Georgia Power, November 18, 2021.
2 Moody's Credit Opinion, October 26, 2022.
3 Fitch Georgia Power Company, October 4, 2022.

these analyses and including an adjustment for flotation costs, Mr. Coyne recommends an allowed ROE equal to 11.00% for Georgia Power in this proceeding. (Tr. 631, 673.) Mr. Coyne's recommendation also considers the general economic and capital market environment and the influence capital market conditions exert over the results of the DCF, CAPM, and Risk Premium models. (Tr. 632.) An 11.00% ROE is a fair, forward-looking rate of return on equity that provides the Company with an opportunity to earn a return on its investment over the period in which rates are in effect commensurate with returns that investors expect to earn on other investments of similar risk. (Tr. 678.)

The Commission should also consider that, relative to the 2019 rate case, the three key quantitative components impacting the Company's weighted cost of capital (approved capital structure, projected cost of debt, and allowed cost of equity) in this request results in a net decrease of $18 million to our requested revenue requirement. (Tr. 214.) Over the past three years the Company has taken advantage of a historically low interest rate environment and relatively flat yield curve and is passing those savings to customers with the projected embedded cost of debt. (Tr. 215.) Although presently in a rising interest rate environment, the Company will continue to seek, as it has in the past, financing structures that minimize the impact of cost to our customers.

2. <u>PIA Staff and Intervenors' recommended ROE reductions are drastic, unprecedented, and punitive</u>.

The positions taken by PIA Staff and several Intervenors would undermine Georgia's well-established and balanced regulatory structure by drastically reducing the Company's ROE. PIA Staff's recommended 105 basis point ROE reduction would represent the largest single ROE reduction for Georgia Power in decades and would be particularly egregious in light of the Company's superior performance over the last three years, including during the COVID-19 pandemic. (Tr. 3946.) A 105-basis point reduction in ROE is not consistent with utility performance that exceeds customer and investor expectations. (*See* Tr. 4009.) Since 2019, the Company has performed well, delivering clean, safe, reliable, and affordable electricity to customers while striving to find efficiencies and foster innovation. The ROE reductions proposed by Mr. Gorman, Ms. LaConte, Ms. Reno, and Mr. Ellis would signify a dramatic departure from the gradual approach employed by this Commission over the past several rate cases and would undo the steps the Commission took in 2018 to address the Tax Reform Act and protect the

Company's credit quality from the stresses placed on it by tax reform. (Tr. 3957, 4025, 4108, 4122, 4178-79.) The capital markets would surely view such a reduction negatively as it would represent a radical and dramatic departure from the consistent and historically constructive regulation for which this Commission has a reputation – one where excellence is recognized and rewarded, not punished. (Id.)

PIA Staff and several Intervenors reference the industry average authorized ROEs over various time frames, whether to note that they have been declining since 2009 (Tr. 3480) or have averaged within the range of 9.35% to 10.42% for years 2010 through 2022 to date. (Tr. 2460-62, 2709-11, 2849, 3517-18.) However, Georgia Power is not an average utility and Georgia is not an average state. (Tr. 574.) The Commission has never approved Georgia Power's ROEs based upon industry average and has, in fact, historically established Georgia Power's ROE set point above the national average. (Tr. 575.) Indeed, the Commission has historically approved, through the three-year ARPs, ROEs approximately 100 basis points above the industry average, taking into consideration the Company's superior performance, ability to manage operating risk and agreement not to seek rate relief for three years except in limited circumstances.

The Company's proposed ROE of 11.00% is thoroughly supported by Mr. Coyne. While PIA Staff Witness Gorman, GIPL Witness Ellis, GAM Witness LaConte, and DOD Witness Reno questioned Mr. Coyne's results by taking positions that can differ among professional experts, Mr. Coyne appropriately defended his positions based on his considerable and extensive knowledge and expertise. (Tr. 2752, 3495-96, 3652-53.) For example, several parties questioned Mr. Coyne's use of market capital structure adjustment to correct for financial risk differences between the proxy group's market capital structure and the book regulatory capital structure proposed for Georgia Power. Mr. Coyne defended this adjustment as correct and necessary to provide an overall cost of capital commensurate with market expectations.

PIA Staff and Intervenor recommendations do not represent current market conditions and would not result in full recovery of the Company's cost of equity. (Tr. 3957, 4116, 4120-21, 4179.) As shown in Table 1 below, three of the parties who recommended ROE adjustments in this case who also made ROE recommendations in the Company's 2019 Rate Case, recommended *higher* adjustments in the 2022 Rate Case than they did in the 2019 Rate Case. (Tr. 1295, 1471, 2716, 3441, 3264.) Comparing these parties' prior ROE recommendations with current

recommendations inherently acknowledges that the cost of capital has increased in the last three years.

Table 1

Party	2019 Recommended ROE	2022 Recommended ROE
Georgia Power	10.9%	11.00%
Department of Defense	9.1%	9.47%
PIA Staff	9.2%	9.45%

Despite implicitly acknowledging that the cost of capital has increased since 2019, each party recommending an ROE setpoint proposed a value *lower* than the Company's current ROE. These parties provide no justification for recommending such severe reductions in the Company's cost of equity since the last base rate case. Mr. Ellis' 5.54% ROE recommendation is almost 500 basis points below Georgia Power's current ROE, nearly 400 basis points below the 9.53% average authorized ROE for vertically integrated electric utilities in 2021 (Tr. 4122, 4178), and 300 basis points below any return authorized for any electric utility in at least 40 years. (Tr. 4117, 4178.) In fact, Mr. Ellis' recommendation is so low as to be confiscatory and severely beyond the zone of reasonableness for a vertically integrated investor-owned utility.

For these reasons, Mr. Gorman, Ms. LaConte, Ms. Reno, and Mr. Ellis' recommendations are not only unsupported but also are unduly punitive in light of Georgia Power's record of strong performance. (Tr. 3957.) The ROE reductions proposed by PIA Staff and Intervenors are a dramatic departure from the Commission's constructive and supportive regulatory environment over the past several rate cases (Tr. 3957, 4025, 4108, 4122, 4178-79), and would surely be viewed negatively by the capital markets, as Mr. Fetter unequivocally testified. (Tr. 4184.)

3. PIA Staff's and Intervenors' proposed equity reductions would destroy the necessary balance agreed to following the Tax Reform Settlement and affirmed in the 2019 Rate Case and would threaten the Company's financial integrity.

Many of the same parties proposing drastic ROE cuts also propose to reduce the equity portion of the Company's capital structure, including PIA Staff's recommended 500 basis point reduction from the level deemed appropriate by this Commission just three years ago. Such unprecedented and severe changes would significantly impair the Company's financial integrity,

which is necessary to ensure its ability to raise capital at reasonable cost and upon reasonable terms for the benefit of customers.

Although Mr. Gorman acknowledges that the Company's authorized equity ratio was previously increased due to the negative effects of the 2017 TCJA, he completely ignores that these negative effects continue today. (Tr. 3538.) Instead, he proposes that the Company's equity ratio should be reduced to 51% once Vogtle Unit 4 is placed in service (Tr. 3515), wrongly assuming that the construction of Vogtle Units 3 and 4, rather than the TCJA, was the catalyst to increase the Company's equity ratio to 56%. (Tr. 3540, 3542, 3545.) As such, the placement of Vogtle Units 3 and 4 in service should not be an advance trigger for a reduction in the Company's equity ratio. The Commission should adhere to its prior policy findings and maintain the Company's equity ratio due to the continued risk and negative impacts from the TCJA.

The Settlement Agreement approved in the 2019 Rate Case left it to the Commission to determine the Company's appropriate capital structure. Based on the evidence presented in that case, the Commission found the appropriate capital structure to be 56% equity and 44% debt. (Tr. 3440-41.) As noted in the Commission's Short Order Adopting Settlement as Modified in the Company's 2019 Rate Case in Docket No. 42516, the Company's equity ratio was adjusted from 51% to 55% as a part of the TCJA Settlement in Docket No. 36989 ("Tax Reform Settlement") to address the negative implications of tax reform and provide support for maintaining the Company's credit profile. (Tr. 3537-38.) The Commission further determined that the "proposed capital structure of 56% common equity level is just and reasonable considering all of the evidence presented."[4] There have not been, nor are there anticipated to be, any changes to the TCJA or its negative impacts on the Company since the Commission approved the 56% equity, 44% debt capital structure in the Company's 2019 Rate Case that would justify lowering the Company's equity ratio. (Tr. 3956.)

GAM Witness LaConte recommends the Company's equity ratio should be more in line with the average equity ratio for the companies included in Witness Coyne's proxy group that have similar credit ratings as Georgia Power or should not exceed 53%. (*See* Tr. 2713.) Ms. LaConte's proposal of 53% equity is not based on a careful and accurate analysis of the credit rating

[4] *Short Order Adopting Settlement Agreement as Modified*, Georgia Public Service Commission, Docket No. 42516 (December 17, 2019) at 8.

implications of her recommendation. If a 53% equity level were adopted by the Commission, that decrease would cause over 200 basis points of deterioration in FFO to debt, harming the Company's financial integrity. (Tr. 3956-57.) Additionally, as mentioned earlier, the 56% equity level set in the 2019 rate case appropriately mitigates the negative credit impacts of the TCJA. (Tr. 3957.) The impacts of the TCJA still exist; therefore, the Company must maintain its 56% equity ratio as carefully reviewed and approved by the Commission in the 2019 rate case. None of the capital structure recommendations proposed by PIA Staff or Intervenors adequately reflect Georgia Power's need for continued access to capital on reasonable terms and the importance of maintaining its credit quality. (Tr. 4182.) Therefore, the Commission should reject the proposed capital structure changes proffered by PIA Staff and Intervenors.

4. Errors in PIA Staff Witness Gorman's FFO to debt calculations result in an incorrect conclusion that the Company's future cash flows are sufficient to yield an appropriate credit rating going forward.

The Company's request in this case carefully sought to ensure the Company could continue to access capital markets to meet the future needs of customers, continue to provide high levels of service and preserve the opportunity to earn a fair return on investments necessary to support a well-run and efficient utility. To evaluate how its recommendations would impact Georgia Power's credit ratings, the Company calculated its FFO to debt ratio, which is a financial metric used to assess risk based on the Company's ability to pay off debt using net operating income alone. (Tr. 799-800.) Mr. Gorman acknowledges the importance of maintaining the Company's FFO to debt (financial risk metrics) above the credit rating agencies' general benchmarks and tries to present his analysis with that in mind. (Tr. 3531-33.) However, due to an error in calculating the FFO to debt ratio, his resulting proposition would undermine the Company's ability to meet the rating agencies' expectations of restored credit metrics to levels supported by Witness Fetter.

Debt imputation is the act of adding debt-like fixed obligations to a utility's "traditional" debt balance when calculating FFO to debt. (Tr. 3953.) For many years, S&P has viewed certain components on the balance sheet, including pension obligations, lease liabilities and asset retirement obligations, as similar to debt and therefore adds them to the debt balance when calculating credit metrics. (Id.) S&P uses the information included on the Company's publicly available balance sheet and accompanying financial disclosures to obtain the necessary

information for the proper debt imputation calculation. (Id.) Georgia Power has no off-balance sheet debt, or any other off-balance sheet components, that the rating agencies use when calculating adjusted debt. (Tr. 3954.)

Mr. Gorman and the Company agree that these debt-like obligations are the type of debt imputations that are appropriate to include in estimating S&P's FFO to debt calculation. (Tr. 3669, 3954.) However, due to the confusion around where these debt-like components are identified, these components were omitted from Mr. Gorman's calculations. (Tr. 3671-72; 3678.) Mr. Gorman should have included the debt imputations related to these debt-like components in his estimated recalculation of S&P credit metrics, as he did in the 2019 rate case. (Tr. 3954.) By excluding more than $5.5 billion of debt imputations, Mr. Gorman's credit metric expectation is significantly overstated and fails to illustrate the harmful effects of his recommended ROE and equity ratio. (Tr. 3952.) The magnitude of this error casts substantial doubt on the reliability of Witness Gorman's statements supporting how his recommendations affect the Company's credit quality.

In his recalculation of one of S&P's most important credit metrics, FFO to debt, Mr. Gorman omitted the important debt imputation methodology S&P has directed in previously issued authoritative publications. (*See* Tr. 3678, 3952.) These debt imputations are essential adjustments that must be made to arrive at a properly recalculated S&P credit metric. (Tr. 3676-78, 3953.) Had Mr. Gorman's recalculation included the proper S&P debt imputations, it would have shown that the Company's metrics, assuming Staff's adjustments were accepted by the Commission, are insufficient to maintain sufficient access to capital at reasonable rates. Due to this error and the assumptions serving as the basis for Mr. Gorman's recommendations, the Commission should not adopt PIA Staff's proposed ROE and capital structure, which will be more deleterious to Georgia Power's financial integrity than even PIA Staff intended.

5. <u>The cumulative effect of PIA Staff's recommendations is extremely negative to the Company's financial integrity and the Commission should reject PIA Staff's ROE and capital structure recommendations</u>.

The cumulative negative impact of Mr. Gorman's recommended 9.45% ROE set point and capital structure of 51% equity, beginning in year 2024, coupled with the recommendations of Messrs. Smith and Trokey, would be dramatic and harmful to the Company's financial integrity.

(Tr. 3950.) As stated above, if one were to recalculate Georgia Power's FFO to debt assuming Mr. Gorman's recommended ROE of 9.45% and an equity ratio of 51% in 2024-2025, the results are extremely negative to the financial integrity of Georgia Power. (Tr. 3950.) Further, incorporating the detrimental effects of Messrs. Smith and Trokey's recommendations, the 2023-2025 average FFO to debt would deteriorate by roughly 500 basis points. (Tr. 3951.) The resulting Georgia Power credit profile, assuming the collective recommendations by PIA Staff, would place the Company's financial integrity at or below the lowest acceptable level recommended by Mr. Fetter. (Id.) A key component of this rate case is to maintain the credit quality Georgia Power has today, not diminish it.

Based on the latest Moody's Credit Opinion issued October 26, 2022, Moody's states:

> Georgia Power operates within a credit supportive Georgia regulatory framework which generally provides timely recovery of prudent costs and investments and allows for the company to maintain a typically stable financial profile.

Moody's goes on to state:

> Georgia Power is currently in a pending rate case and will look to address the deferred fuel costs in a filing next February. Depending on resolution of these regulatory filings, we expect Georgia Power's financial profile to improve including a ratio of CFO pre-W/C to debt of about 20% in 2023. Once the new nuclear units are in service and depending on the ultimate investment recovery allowed by regulators as result of the cost prudency review, the majority of which will be completed when Unit 4 is in service, we expect a substantial increase in Georgia Power's cash flow which should translate into considerable improvement in credit metrics.

(Tr. 3951-52.)

The punitive adjustments that Mr. Gorman and Messrs. Smith and Trokey recommend would limit the FFO to debt metric to approximately 20% for the foreseeable future without the opportunity for improvement. Such limitation runs counter to the rating agencies' expectation that, beginning in 2024, Georgia Power will remedy its credit profile such that it assumes a position of improved cash flow and adequate credit quality. (Tr. 118, 125, 132, 3952.) PIA Staff's unreasonable recommendations would harm the Company's credit profile, impair the Company's

ability to improve its credit metrics, disturb the constructive regulatory environment that has benefitted Georgia Power's customers, and harm customers by restricting the Company's access to debt capital at reasonable terms and costs. (Tr. 3951.)

6. The Company's ability to manage its business to meet investor expectations ensures that Georgia Power is in a financially healthy position to meet customer expectations as it delivers clean, safe, reliable, and affordable electric service.

The changes PIA Staff and many of the intervening parties propose are ill-advised and fail to consider the impact of their proposals on the Company's ability to access capital markets on reasonable terms to attract the substantial capital necessary to continue providing customers with the clean, safe, and reliable electric service they deserve and expect. (Tr. 4012.) Customers benefit when the Company balances the interests of all stakeholders because a financially healthy utility can access and attract the necessary capital (both debt and equity) to meet the needs of its customers and is more likely to achieve high levels of reliability and customer satisfaction. (Tr. 3950, 3977.) Customers also benefit from the Company's operating efficiencies in its efforts to meet investor expectations. (Tr. 3950.) The efficiencies gained and the corresponding cost reductions that result from those efforts are provided to customers through savings in rates. (Tr. 264-65, 575.)

In addition to accessing capital markets on a timely basis at reasonable rates, a utility with strong credit ratings shares the benefit of those attractive interest rate levels with customers since the cost of capital is factored into utility rates. (Tr. 797-98, 806.) Conversely, the lower a regulated utility's credit rating, the more that utility must pay to raise funds from debt and equity investors to carry out its capital-intensive operations. (Tr. 798.) In turn, the ratemaking process factors the cost of capital for both debt and equity into customer rates. (Tr.790-91.) This is especially true for a company like Georgia Power, which needs to attract significant levels of capital in the near term for continued transmission and distribution investments, environmental compliance, and the construction of new nuclear units, all while continuing to safely and reliably serve customers. (Tr. 794, 799, 806.) Therefore, the Commission should approve the rate adjustment and capital structure Georgia Power proposes in this case so that the Company remains positioned to continue meeting the energy needs of our customers and the communities we serve.

C. The Company Cannot Accept an ARP as Proposed by PIA Staff and Some Intervenors.

Under Georgia law, the Company's agreement is required to enter into an ARP. Without an agreement, this case must be resolved under traditional ratemaking standards, which involve a single test year analysis and would eliminate the positive attributes of a three-year predictable plan such as the institution of earnings ranges and earnings sharing mechanisms. O.C.G.A. §§ 46-2-25; 46-2-26.1. Without an ARP, more frequent, successive rate cases would be required over the next three years to accomplish what a three-year ARP can accomplish now. (Tr. 3958.) However, successive annual cases do not possess the positive attributes of rate certainty, rate stability, or the earnings sharing mechanism present in an ARP. (Id.) PIA Staff and several Intervenors have proposed radical and harmful modifications to the ARP that should be rejected. PIA Staff goes so far as to suggest that the Commission impose an earnings cap (*see* Tr. 1379), which is fundamentally inconsistent with the concept of the ARP sharing mechanism that benefits both customers and the Company. (Tr. 3945-46.) These proposed modifications undercut core aspects of the ARP, are unacceptable, and the Company would not agree to such an ARP.

1. Continuation of the Company's current earnings band will retain many of the positive structural features of the ARP for customers' benefit.

The Company requested to maintain the current approved earnings band of 9.50% to 12.00% within an ARP construct that provides for the Company to share 80% of any earnings above the band with customers. (Tr. 208.) Under this arrangement, all stakeholders win as demonstrated by the Company's consistent delivery of exceptional service while keeping rates low in relation to other utilities. Maintaining the earnings band in its current form affords the Company the opportunity to continue the innovation and efficiencies in operations that the Company was able to identify since the last rate case. Customers have benefitted under this structure and will continue to benefit under the Company's proposed ARP and earnings band if approved by the Commission.

2. PIA Staff and Intervenor-proposed changes to the earnings band fail to incentivize the Company to innovate and seek operational efficiencies that provide customer benefits.

a. The earnings sharing mechanism should not be modified and PIA Staff's proposed earnings cap should be rejected.

PIA Staff has proposed an earnings band ranging from 8.45% to 10.45% and recommended that 100% of earnings above the band be applied to deferred costs rather than split between customers and the Company. (Tr. 1379.) PIA Staff's proposal amounts to an earnings cap by eliminating any retained revenues earned above the earnings band. (Id.) If an earnings cap was approved in this manner, the Company would not be appropriately incentivized to innovate and seek operational efficiencies during the ARP period, which is not in the best interests of customers. In addition, the top end of the earnings band proposed by PIA Staff is set artificially low, below even the Company's cost of equity. PIA Staff's elimination of the sharing mechanism and imposition of the earnings cap is unreasonable and should be rejected.

b. The Company will not accept a narrowed earnings band as recommended by DOD Witness Blank.

It appears that Mr. Blank is only recommending an ROE earnings band of 100 basis points above the ROE if the Commission authorizes an ROE below the Company's requested 11%. (Tr. 3413.) This change would result in the top of the earnings band being lower than the 12% proposed by the Company. Otherwise, Mr. Blank reiterates his recommendation from the 2019 rate case that the earnings band be narrowed to +/- 50 basis points above and below the target ROE based on the assumption that it would reduce the risk to the Company. (Tr. 3412.) However, narrowing the earnings band may increase risks and uncertainty to customers, altering the fundamental nature of the ARPs that have been in place for the last 25 years. (Tr. 3962.) Georgia Power has rightly proposed to maintain the current approved earnings band of 9.50% to12.00%, consistent with the structure of the earnings bands previously approved by the Commission for the last several decades, and recommendations to the contrary should be rejected. (Tr. 208, 3962.)

c. The Commission should reject Commercial Group's recommendation to adjust the earnings band commensurate with any adjustment to the requested 11% ROE set point.

The Commission should reject the Commercial Group Witness Chriss' recommendation to adjust the earnings band commensurate with any adjustment to the requested 11% ROE set point. (Tr. 2453.) If the Commission were to authorize a set point ROE less than the Company's requested 11%, the bottom end of the earnings band should remain at 9.50% with the top end of the earnings band set at 12.00%, which is consistent with the structure of the earnings bands previously approved by the Commission.

3. Customers benefit from the Commission's adoption of an ARP.

As a result of the ARP currently in place, the Company returned approximately $297 million to customers through the earnings sharing arrangement approved by the Commission in the 2013 base rate case, without jeopardizing superior customer satisfaction or reliability. (Tr. 3203, 3961.) In the absence of an ARP, there would be no earnings sharing mechanism or incentive for the Company to share earnings with customers. (Tr. 3945.) In addition, under the ARP, the amount customers pay through rates does not change when the Company's earnings are within, or exceed, the band because rates are established at the ROE set point. (Tr. 3961.) As previously mentioned, the sharing mechanism is a critical component of the ARP and appropriately encourages the Company to look for efficiencies and process improvements. (Tr. 3961.) This incentive provides the opportunity for increased earnings that benefit both customers and the Company.

Three-year ARPs also avoid the potential for more frequent base rate cases, provide rate stability and predictability to customers, and signal the type of regulatory consistency viewed favorably by credit rating agencies. Further, because the Company surrenders its right to file a full rate case during the three-year term when the ROE is within the authorized earnings band, the Company assumes the risks of changing conditions during the term of the ARP. (Tr. 3958.) For example, the level of inflation may increase more than projected, the cost of debt or equity might increase, sales may be less than forecasted, or the Company's overall cost of service may be more than forecasted. (Id.) A three-year rate plan also holds the Company accountable for inefficiencies or cost overruns due to rates being set at a predetermined level for the duration of the three-year

period. (Id.) The Commission's history of adopting three-year ARPs benefits customers and the Company alike. As such, the Commission should adopt the structure of the Company's proposed ARP and reject proposals that would alter that structure.

4. The Commission should reject PIA Staff's recommended data revisions to the annual compliance filing process as an unnecessary erosion of the ARP process.

The data elements currently updated in the annual Compliance Filings established in the Settlement Agreement approved in the Company's 2019 Rate Case provide benefits to customers and equity to all parties. The additional elements that Staff proposes to incorporate into the annual Compliance Filings risk transforming this established, efficient, and effective process into a burdensome, mini rate case proceeding. (*See* Tr. 1373.) More importantly, as the number of data elements to be re-estimated and readdressed on an annual basis via the Compliance Filings increases, the more the benefits and value of the three-year ARP are undermined. (Tr. 3980; 4008.)

D. The Commission Should Reject Most of PIA Staff and Intervenors' Revenue Requirement Adjustments.

1. The Commission should reject PIA Staff's recommendation to use the test period revenue requirement to set rates in the first year of the three-year ARP.

The Company has included in its filing both the test period revenue requirement and the revenue requirements for each plan year 2023 through 2025. (Tr. 226.) However, the Company supports setting the rates in the first year of the proposed ARP based on the revenue requirement for 2023. The revenue deficiency calculated for the calendar year ending December 31, 2023, rather than the deficiency for the split test year, reflects a more accurate depiction of the costs the Company will incur in its first year under a new ARP when the new rates are effective. Determining the revenue deficiency using the calendar year reduces regulatory lag. In the Company's Errata Filing, the projected revenue deficiency based on the traditional test period and the 2023 calendar year is $459.8 million and $612.3 million, respectively, resulting in a difference of $152.5 million. This difference illustrates that basing the year one rate increase on the split test period's revenue deficiency would create a revenue shortfall of $152.5 million in the very first year of the three-year period. Setting rates based on the test period would not permit the Company to timely recover its prudently incurred costs in serving customers. Therefore, the Commission

should reject PIA Staff recommendations to use the test period revenue requirement to set first year rates in 2023.

2. The Commission should reject PIA Staff's recommendation to use any revenue sufficiency to accelerate recognition of deferred costs.

Georgia Power's proposed case does not have a projected revenue sufficiency in 2023 to apply to deferred costs as proposed by PIA Staff. (Tr. 3959.) As stated previously, the Company's revenue deficiency should be based on the calendar year 2023 revenue requirement rather than the test period, if the Company's ARP is adopted. As such, the Commission should reject PIA Staff's recommendations to apply any revenue sufficiency to accelerate recognition of deferred costs or to amortize a portion of CCR ARO compliance costs. Nevertheless, as stated in the Company's rebuttal testimony, the Company generally agrees with PIA Staff's concept of applying revenue sufficiency, if any, to certain regulatory assets to maintain rate stability for the customers. (Id.)

3. In the interests of greater rate stability, the Commission should adopt the Company's proposed levelized rate increase rather than the step increase proposed by PIA Staff.

As part of its recommended ARP, the Company proposed a levelized approach to balance the benefit to customers from three years of stable and predictable rates with the Company's need to timely recover its projected revenue deficiency. (Tr. 73.) Rate stability provides customers with a beneficial tool when budgeting for their utility costs and provides a predictable revenue stream for the Company. A levelized approach to rate increases shifts economic risks to the Company by insulating customers from the impacts of a possible downturn in the sales forecast or cost increases. (Id.) This approach makes practical sense as the Company is better equipped to manage negative economic factors that impact the cost of running the business, as opposed to asking customers to shoulder the impacts, which would occur with increased rates under step increases. In addition, customers are fairly compensated for the projected over-collection in the first two years of the levelization. For the projected advancement of revenues in 2023 and 2024, the Company proposes to defer the amount as a regulatory liability, reducing retail rate base and giving customers credit on the advanced amount based on the Company's full weighted average cost of capital. This

proposed deferral reduces the levelized revenue requirement requested by the Company and fully amortizes the advancement by the end of 2025. (Tr. 3960-61.)

In contrast, the step increase approach would increase customer rates by an increasing amount during each of the next three years. Although an annual increase would result in a lower than requested projected revenue requirement for years 2023 and 2024, the increase for 2025 would be greater than the levelized amount, and rates would increase more overall during the ARP. The levelized approach results in $43 million less being billed to customers than a step increase approach over the three-year ARP. (Tr. 3960, 4017.) The fluctuation in projected costs year-to-year under a step approach creates uncertainty for customers. (Id.) Although the Company shares PIA Staff's interest in rate stability, levelizing the proposed increases over the three-year ARP is the more appropriate approach for customers.

4. The Commission should reject PIA Staff's O&M reductions that are based solely on prior historical levels of O&M expense.

The Company's O&M expenses are complex and driven by many factors, such as timing and scope of outages, scheduled maintenance cycles, repair work, medical claims, the labor market, and contractor rates. The conditions in the historical period are not identical to the test period and the Company and its business units consider all these factors in the development of their respective budgets for the upcoming three-year period. (Tr. 3967.) In addition, the historical years used by PIA Staff Witness Mugrace includes years 2020 and 2021, which were greatly impacted by the COVID pandemic and are not representative of a "normal" year that should be relied upon as reflective of costs to be incurred in the forecasted periods. (Id.) Simply put, while historical expenses may be an input into the Company's budgeting process and considered in forecasting O&M expenses, it would be inappropriate to rely only on historical levels of O&M expense as the sole indicator of future expenses in the coming three years.

Annually, the Company utilizes input from all areas of the business to plan and budget the resources needed in support of expected workload for the upcoming five-year forecasted period. The Company considers planned outage schedules, expected maintenance activities, asset and vegetation management programs, customer service needs, technology, fleet, materials, staffing levels, contractor rates, and expected inflation when developing the budget. Budget assumptions are vetted and approved to ensure consistency across business units. During this process, Georgia

Power reviews expenses and adjusts budgeted amounts based on known increases or decreases, accordingly. (Id.) Even with known cost increases, budgets may fluctuate over a given period of time due to multiple factors, including unit outages, changes in workforce needs for both Company labor and contract labor, Company benefit costs, and Commission-approved items such as storm recovery and demand side management ("DSM") expenses. The Company does not create its budget by simply applying an inflation factor to all the actual or historic year expenses, in part because the Company's O&M costs are not static over time. (Id.)

Moreover, the Company is constantly focused on managing its O&M expenditures, emphasizing cost containment as part of its corporate culture, as reasonable and necessary cost containment is in the best interest of both the Company and its customers. (Tr. 3968.) The Company has identified efficiencies in nearly every part of its business while still providing superior customer satisfaction and reliable service to customers. If historical expenses alone were considered in setting the appropriate O&M expenses for the ARP period, they would not adequately capture these efficiencies and cost savings for customers. The Commission should reject each of PIA Staff's recommendations to replace the Company's carefully budgeted O&M expense estimates with simple historical averages.

5. The Commission should approve the Company's request to recover the costs associated with the innovation center in retail rates.

PIA Staff Witness Mugrace argues that the Company's costs incurred related to the Energy Innovation Center ("EIC") should be removed from retail rate base because such costs are "not known and measurable" and "may not achieve any objective with respect to reliability, affordability, sustainability or customer engagement." (Tr. 2027.) Mr. Mugrace likens these expenses to research and development costs and claims that there is no evidence of benefit to customers. (Id.) The Company disagrees with PIA Staff's characterization of the EIC and the allegations that it provides no known or measurable benefit to customers. The EIC is related to but distinct from Research and Development in that the EIC is focused on education and exchanging ideas and information with all customer segments and stakeholders. (Tr. 3969.) The Company engages directly with customers through the EIC platform to share with customers general educational materials on innovative technologies, discuss end-use applications that will be beneficial for customers, bring stakeholders together, and establish a foundation for future

partnerships between the utility and customers. Establishing a forum to circulate these ideas around technology innovation, and their market milestones, is fundamentally beneficial to Georgia Power's customers because it has led to project activities that deliver cost saving efficiency and sustainability outcomes, with the potential to deliver grid-level benefits that improve reliability. (Id.)

For example, as explained by Mr. Robinson in the Company's rebuttal hearing, the Company's transition to using unmanned aerial systems to inspect transmission lines was an idea brought forth through the EIC. (Tr. 4039.) These types of efforts lead to direct customer engagement and benefits that are tangible, known, and measurable. The EIC is a resource for customers and stakeholders to learn about new energy technologies and how they may participate in their deployment, where applicable and appropriate. The Commission has previously approved the recovery of these costs in retail rates and should do so again here.

6. The Commission should approve the Company's request to recover the costs associated with service awards and recreation costs in retail rates.

Contrary to the recommendations of Mr. Mugrace, the Company's costs incurred related to service awards and recreation costs are not premature and are known and measurable. The Company's service award program is a part of the overall compensation package offered to all full-time and part-time active employees, which helps motivate and retain the talent needed to efficiently operate the Company's business. It demonstrates recognition and appreciation to employees for Company service at specific service intervals, which are estimable and measurable. Further, recognizing valuable and dedicated employees is important to the Company and valuable in providing consistent and top-notch service to Georgia Power's customers. These costs are appropriately recovered in retail rates. The Commission has previously approved the recovery of these costs in retail rates and should do so again here.

7. The Commission should approve the Company's request to recover the costs associated with association dues, community service, and experimental costs in retail rates.

Witness Mugrace argues that costs associated with association dues, community service, and experimental costs do not benefit ratepayers in the provision of safe and adequate service. (Tr.

2038.) However, these costs are necessary to operating the business and our customers benefit from such activities. Through these efforts, the Company develops technology efficiencies that reduce O&M expenses and equipment improvements that improve the reliability of the grid. As a member of certain associations, the Company and its employees learn, grow, and contribute to the sustainability of the electric industry. For example, as members of the Institute of Electronic and Electronics Engineers, the Company has subject matter experts who sit on standards committees, which directly benefits the Company's customers. (Tr. 4042.) Costs associated with community organizations, community development, economic development, and other business issues also benefit the communities we serve. Investments in these areas help the Company engage with customers and communities, which allows for growth and sustainability across the state. Again, the Commission has previously approved the recovery of these costs in retail rates and should do so again here.

8. To appropriately account for the impact of rising inflation on the Company's cost of service, the Commission should approve the Company's calculation of incremental inflation in its revenue requirement.

The Commission should reject Mr. Mugrace's proposed inflation reductions as unnecessary and inappropriate. Mr. Mugrace argues that because inflation may not stay elevated during the three-year rate plan, the Company's inflation adjustment forecast is too high resulting in rates being set too high for utility service. (Tr. 2043.) As stated in the Company's rebuttal hearing, inflation has continued to increase since the Company's filing in June 2022 (Tr. 4014) and is likely already underestimated rather than overestimated in the Company's test year and each ARP year. Therefore, no reduction to the Company's estimated incremental inflation is justified.

In addition, Mr. Mugrace errs in calculating his inflation adjustment. As explained in the Company's rebuttal testimony, the Company began to see significant price increases across all aspects of its business consistent with the rising inflation factors found in the Employment Cost Index ("ECI") and Gross Domestic Product ("GDP") deflator. (Tr. 3971.) In response to these signals, the Company adjusted its projected O&M expenses to account for these cost increases in this filing by identifying labor and non-labor costs that typically would fluctuate based on inflation factors and applying the incremental increase in ECI and GDP inflation rates to the appropriate cost types. Although Mr. Mugrace states that the ECI is an appropriate source of inflation rates for

labor costs (Tr. 2042), he ultimately used only the lower GDP index to escalate total non-Production O&M expenses, including labor and non-labor costs, to calculate his incremental inflation adjustment. (Tr. 2042-43.) However, to appropriately calculate an inflation adjustment, the O&M expenses need to be separated into labor and non-labor charges and the ECI and GDP rates need to be applied to the respective costs, as the Company did in performing its calculation of the incremental inflation adjustment. (Tr. 3972.) Mr. Mugrace's adjustments underestimate and fail to capture the impact of inflation on the Company's revenue requirement. Based on the foregoing error and the lack of need to adjust the incremental inflation in the Company's proposal, the Commission should reject PIA Staff's inflation adjustment.

9. The Commission should reject PIA Staff's proposals that eliminate cost recovery for costs associated with the Company's employee compensation programs.

To provide its award-winning service to customers, Georgia Power must attract and retain a high level of skilled and professional employees, who are paid competitively and appropriately based on their role. Georgia Power's employee compensation program is designed to provide competitive compensation at levels targeting the 50th percentile of the appropriate markets. The Company's well-balanced and market competitive compensation program provides different types of compensation that are commonly known and recognized by compensation professionals to be market appropriate to retain and attract talent, which includes (i) fixed based compensation, (ii) variable short-term compensation, and (iii) long-term stock-based compensation. The goal of providing different types of compensation is to create a balanced incentive system to ensure that employees are providing the best service to customers at the least cost. Evaluating compensation as a whole allows Georgia Power to maximize the effective use of resources essential to efficiently serve its customers by linking a portion of the employees' compensation package to operational and financial performance, thus aligning the compensation programs with Georgia Power's need to attract, engage, retain, and motivate its highly skilled workforce.

a. The Commission should reject PIA Staff's proposed disallowances related to the structure of the Company's total compensation plan.

According to the testimony of PIA Staff Witnesses Smith, Trokey, and Mugrace, certain portions of the Company's total compensation program – the long-term incentive stock-based

compensation plan and the amounts of the PPP attributed to financial goals – do not benefit customers and should therefore be borne by shareholders instead of customers. (Tr. 1364-65, 2047-48.) The Company strongly disagrees with this opinion. The long-term incentive-based at-risk compensation program incentivizes employees to make decisions that are in the long-term best interests of customers and the Company. (Tr. 3977.) Customers benefit from a financially healthy company, which should be measured over the short- and long-term to ensure that the decisions made by the Company are optimized for both short- and long-term benefits. This is especially true in the utility industry, where decisions related to infrastructure and other major capital projects may have long-lasting financial consequences to all stakeholders, including customers. (Id.) Customers would be harmed if the Company were to drive its employees to sacrifice long-term financial health for short-term benefits. By designing the at-risk portion of the total compensation plan to include longer-term goals, the Company achieves an appropriate incentive balance that motivates employees to deliver safe, clean, and reliable electric service to our customers in a manner that is economically efficient both now and in the years that follow. (Id.)

The Company's existing compensation policy is necessary to attract, motivate, and retain a highly skilled, dedicated workforce. If "at-risk" components of the employee compensation program, which includes the long-term incentive stock-based compensation plan and the amounts of the PPP attributed to financial goals, were eliminated or significantly reduced, the Company would have to commensurately increase other components of its total compensation package – such as direct salary costs – to maintain its competitiveness as an employer within the industry and to continue to attract a skilled workforce. (Tr. 3975-76.) It would result in higher fixed costs and poor alignment of all stakeholders' interests, including customers. (Tr. 3976)

PIA Staff's proposed disallowance of these portions of the employee compensation program are not based upon any supporting data or market analysis that the Company's expenses are excessive or that the programs are not competitive with the external market. There is also no basis for Mr. Mugrace's assertion that, "[t]hese types of incentive costs benefit the Shareholders of the Company, and of SCS and SNC, and do not directly benefit the ratepayers in the area of safe and reliable utility service." (Tr. 2332.) In fact, the opposite is true. Georgia Power could not efficiently operate its business or provide customers with clean, safe, and reliable utility service without its dedicated workforce. The budgeted costs to attract, retain, and engage employees are

expenses that arise in the ordinary course of the Company's business and should be included in the Company's revenue requirements and recovered in retail rates. Moreover, the payroll tax expenses associated with stock-based compensation are a prudently incurred cost of doing business and, therefore, should also be recovered from customers. The Commission should reject PIA Staff's recommendations to remove the "at risk" portions and stock-based compensation from rates.

b. Georgia Power's SERP, non-SERP, and retention expenses are necessary to retain highly skilled professional employees and are appropriately recovered in retail rates.

The Company's costs related to Supplemental Executive Retirement Plan ("SERP") and non-SERP benefit costs as well as employee retention are necessary expenses to ensure the attraction and retention of our highly skilled management team of leaders. The SERP and non-SERP programs are used to attract and retain senior management level employees across the various business units of the Company who have key roles, experiences, and skills in managing employees to ensure Georgia Power continues to provide reliable customer service and maintain our standards of safety. (Tr. 3973.) These types of programs are common for other companies who provide qualified pension plan benefits and are regularly evaluated to ensure that the total compensation for our employees, including these pension benefit programs, is market competitive. (Tr. 3973-74.) Furthermore, these non-qualified pension programs are not funded and therefore, are not covered by corporate-owned life insurance benefits as stated by Mr. Mugrace in his testimony. (Tr. 2036.)

In addition, employee retention agreements are utilized as targeted, strategic compensation tools to retain high-performing employees in critical roles throughout the Company who offer deep experience, knowledge, and expertise that is highly sought after and crucial to retain. These agreements are entered into in direct response to specifically identified market pressures. Such pressures often include recruitment by Company competitors and peers, within and outside of the Company's industry, as well as within and outside of the Company's geographic footprint. Employee retention costs allow the Company to continue providing excellent service for our customer base and further maintain the resiliency of our infrastructure. (Tr. 3974.) Further, these costs offset the potential future expenses that would be incurred to recruit, develop, and train

substitute employees for these key roles. As noted above, the Company could not offer superior customer service and clean, safe, and reliable service in the absence of a strong internal team. Therefore, these costs are operating expenses of the business and appropriate for inclusion in retail rates.

c. Limiting the Company's Performance Pay Program ("PPP") compensation to just operational goals under incentivizes the Company's employees to innovate and find better ways to serve customers.

PIA Staff Witness Mugrace recommends disallowing two thirds of the Company's PPP from recovery in retail rates. (Tr. 2047-48.) This recommendation undermines the strength of the Company's compensation structure and will negatively impact every single employee of Georgia Power. Mr. Mugrace bases his recommendation on the assumption that compensation related to financial goals and earnings per share only benefit shareholders and exclude benefits for customers. (Id.) However, Mr. Mugrace offers no evidence or supporting testimony to validate such an assumption. In contrast, Company Witnesses clearly explained that without the long-term incentive stock-based compensation plan and the amounts of the PPP attributed to the Company's financial goals, the Company would have to commensurately increase other components of its compensation package, resulting in higher fixed costs. (Tr. 3950, 3977-78.) Goals based on financial metrics – when included in an incentive compensation plan designed to balance financial and operational goals – provide benefits to customers by reducing expenses, creating greater efficiencies in operations, ensuring a financially strong company, and allowing access to the capital markets at a low cost. (Tr. 3978.)

Georgia Power seeks to create a balanced incentive system to ensure that employees provide the best service to customers at the least cost. Evaluating compensation as a whole allows Georgia Power to maximize the effective use of resources essential to efficiently serving its customers by linking a portion of the employees' compensation package to operational and financial performance and allows for the alignment of the compensation programs with Georgia Power's need to attract, engage, retain, and motivate its highly skilled workforce. A well-designed total compensation program using sound compensation practices and principles provides a balance between operational focus and financial focus for both the short term and longer term to drive employee behavior in ways that balance the interests of customers and shareholders alike. A

compensation plan that contains only operational goals might inappropriately drive employees to use more financial resources than necessary to achieve operational success, while a plan that contains only financial goals might inappropriately drive employees to make decisions that adversely impact operational success. (Tr. 3978.) A balanced program of incentive compensation is a powerful tool that drives employees to put the customer at the center of all we do while sustaining the financial integrity of the Company.

Disallowing recovery of a financial component for a level of standard market pay forces a utility to consider modifying the entire incentive design to be based on operational measures alone (which are recoverable) and eliminate financial components of the incentive program design. However, making this change to an operational-based incentive program design would not be in the best interests of customers, as it would encourage focusing solely on operational performance without regard to or accountability for operational costs. (Id.) This imbalance is not in the best interests of customers, as the failure to appropriately consider operational cost impacts could lead to higher rate increases for customers in the future. As such, the Commission should reject PIA Staff's proposed disallowance and limitation of PPP compensation to only operational goals.

10. The Commission should approve the Company's proposed treatment of the remaining net book value for units retired in the 2022 IRP as well as Bowen Units 1-2 and Scherer Units 1-3.

The Company has proposed to amortize the regulatory assets for Plant Wansley Units 1-2, Plant Wansley Unit 5A, and Plant Boulevard Unit 1, which were retired by August 31, 2022 in accordance with the Company's 2022 IRP, over their remaining useful lives as approved in Docket No. 42516. These proposed amortization periods are consistent with similar regulatory assets and PIA Staff did not object to the Company's proposal. As such, the Commission should approve the Company's proposed recovery and regulatory treatment for these assets. In addition, the Commission should approve the Company's requested depreciation deferral and proposed nine-year amortization for Plant Bowen Units 1-2 and Plant Scherer Units 1-3 beginning January 1, 2023. Based on the depreciation study filed in this case, Plant Bowen Units 1-2 are scheduled to be depreciated through 2027 and Plant Scherer Units 1-3 are scheduled to be depreciated through 2028 in accordance with the retirement dates proposed in the 2022 IRP. For these units, the Company requests the Commission to defer the difference each year between the amount of

depreciation expense recommended under the rates provided in the Company's new depreciation study and the amount depreciation expense would be assuming a nine-year remaining life into a regulatory asset account beginning January 1, 2023. Once the generating units are retired, the deferred regulatory asset balance, including any remaining undepreciated balance at the retirement date, would be amortized over the remainder of the nine-year recovery period ending December 31, 2031. The Company's request is reasonable and was unchallenged in this case. The Commission should approve the deferral and amortization of Bowen Units 1-2 and Scherer Units 1-3 as requested by the Company without modification.

11. The Commission should reject GAM's proposal to prohibit the Company from earning an ROE on unrecovered CCR ARO compliance costs until securitization is authorized.

As Witness Pollock admitted upon cross examination, securitization is not currently an option in Georgia and would require a change in state law to implement. (Tr. 2606.) As such, denying the Company the opportunity to recover all of its financing costs on any unrecovered CCR ARO compliance costs based on an option that is currently unlawful amounts to a disallowance and inappropriately and prematurely assumes that such costs were not prudently incurred. It would be inappropriate to deny the Company recovery of currently incurred financing costs based solely on the potential for future securitization legislation, over which neither the Company nor the Commission have control, and which might never come to fruition. Securitization is not needed as this Commission already has all the tools necessary to appropriately balance the needs of our customers and the Company. (Tr. 2740.)

The Company's CCR ARO compliance costs are required to comply with federal and state environmental regulations and are appropriately included in rate base. The Commission has approved the Company's Environmental Compliance Strategy, which included the Company's ash pond closure plans and CCR strategy, as part of the 2022 IRP in Docket No. 44160. (Tr. 1285.) No party in this case filed testimony or presented evidence challenging the appropriateness of the Company's CCR ARO compliance costs sought to be recovered in this case. Further, there have been no changes in the CCR permits issued to Georgia Power or in federal or state CCR regulations

since the 2022 IRP that change the Company's compliance strategy.[5] As such, the Company should be able to timely recover these prudently incurred compliance costs and have the opportunity to recover all of its financing costs, including equity. Witness Pollock's recommendation prevents the Company's ability to recover its actual costs of financing these required expenditures. In addition, Witness Pollock's proposed ratemaking treatment contradicts past treatment of ARO compliance costs and such departure from past precedent is unjustified. The Commission should not unduly restrict the Company's ability to timely recover its prudently incurred CCR ARO compliance costs pursuant to the current and unchallenged recovery methodology and reject Witness Pollock's deferral for securitization proposal.

12. The Commission should reject PIA Staff's alternative revenue forecast.

PIA Staff Witnesses Baron and Wellborn offered testimony proposing nothing more than a higher, alternative revenue forecast for the Commission's consideration to lower the Company's revenue requirement in this case. While the Company appreciates that differences of opinion may exist in the intricacies of forecast modeling, the Company believes the projected revenue forecast included in its filing continues to be the most reasonable and appropriate method to determine the Company's revenue requirement at present rates. Further, PIA Staff agreed that the Company's method was reasonable and did not identify any errors or corrections in the Company's filing. (Tr. 1535.) With no shortcomings in the Company's revenue forecast, there is no action for the Commission to take and no weight should be placed on the recommendations of Witnesses Baron and Wellborn.

13. Other than the proposed extension of the depreciable life of Plant Hatch, the Commission should reject PIA Staff's depreciation recommendations.

PIA Staff Witness Kaufman removes contingency from plant dismantlement cost estimates for coal and gas production facilities, concluding that contingency represents "unexpected

[5] While intervenors questioned Company witnesses during Rebuttal Hearings on an Environmental Protection Agency ("EPA") determination for Plant Gavin in Ohio finalized on November 18, 2022, the EPA determination does not apply to Georgia Power CCR units. Further, the deficiencies noted by EPA in the Plant Gavin determination are specific to Plant Gavin. Georgia Power's compliance plans include designs that address in detail the performance standards required by the regulations.

outcomes" and therefore, should be removed from the depreciation expense calculations for the Company's coal and gas plants. However, when developing cost estimates, contingency is a fundamental element of a comprehensive and transparent estimate. Contingency is necessary to acknowledge and mitigate the risk of inherent cost uncertainties that accompany capital-intensive projects such as dismantlement of a coal or gas fired electric generation facility.

Mr. Kaufman's depreciation adjustments fail to consider factors that may influence current and future plant dismantlements that have not impacted historic plant dismantlements. For example, prior to the retirement of Plant Hammond in 2019, historic retired facilities did not have air environmental controls (e.g., baghouses, scrubbers, Selective Catalytic Reduction Systems). These environmental controls significantly increase the footprint and dismantlement cost of the remaining coal facilities. The Company's historic dismantlement cost estimates, including contingency, have been included in retail rates and the Commission should continue to approve such cost recovery here.

In addition, PIA Staff Witness Kaufman presented depreciation rates that included calculation errors for Production, Transmission, Distribution, and General functions. When adjusting the lives for these functions, Mr. Kaufman simply extended the useful lives. He failed to consider the impact to other fundamental inputs such as interim retirements and theoretical reserves. By omitting the full impact of the proposed life extensions, Mr. Kauffman proposed depreciation rates that do not properly allocate the capital cost of the Company's assets over their average service lives.

Further, when applying Mr. Kauffman's proposed adjustments to easements, PIA Staff failed to apply the proposed rates to the proper plant in service balances. Rather than applying the proposed rate for easements to the plant in service balance for easements, PIA Staff applied the functional composite rate, which includes easements, to the functional plant in service balance that does not include easements. The combination of these errors, along with the omission of contingency as described above, resulted in understated depreciation expense. Therefore, the Commission should reject all of Mr. Kaufman's depreciation adjustments apart from extending the assumed life of Plant Hatch, with which the Company agrees.

E. Electric Vehicle ("EV") Charging Facilities Benefit Georgia Power Customers and the State and the Commission Should Reject PIA Staff's Recommendation to Remove Georgia Power's Electric Transportation Initiatives from Retail Rates.

1. The Company plays a critical role in supporting the growth of the electric transportation ecosystem in Georgia and its investment provides benefits to Georgia Power's customers.

The Company's continued investments in a statewide EV charging infrastructure have enhanced Georgia's electric transportation capabilities, realized economic savings, and provided environmental benefits while fostering the growth of statewide EV usage. As customer demand for EVs and access to fast charging continues to grow, Georgia Power proposes corresponding expansion of its investments in its customers. (Tr. 462, 464.)

Georgia Power seeks to expand its investment following the successes of those approved in the previous rate case. The 2019 Rate Case approved an $18 million capital investment in the Make Ready program, allowing the Company to partner with communities to deploy EV chargers to a variety of customers, ranging from local businesses to schools and churches. (Tr. 425-26.) The program has since been fully subscribed and now has a waiting list for future participants. (Tr. 426.) Similarly, multimillion dollar investments in the Community Charging program have allowed the Company to expand statewide access to EVs. The Company seeks to transition the program to offer and serve charging stations of last resort in underserved communities that lack a competitive charging market. (Tr. 370, 429, 3964.)

With two major EV manufacturing announcements this year alone, the demand for EVs continues to increase, requiring further expansion of the state's charging infrastructure to meet the energy needs of Georgia Power's customers. (Tr. 78, 461-62; 3964.) The Company's proposed investments will continue to benefit all Georgians through environmental impacts and downward pressure on energy rates. (Tr. 377.)

2. The Commission should approve the Company's requested investment in Make Ready infrastructure, which appropriately fosters greater adoption of EV charging infrastructure by commercial and industrial customers.

In light of the Make Ready program's benefits and the success of the program since its approval in the 2019 Rate Case, the Commission should approve the Company's request to continue investing in Georgia's EV infrastructure by expanding the Make Ready program. (Tr.

141.) To satisfy its obligation of meeting the growing energy needs of its customers, the Company proposes investments of approximately $27 million in each of 2023, 2024, and 2025 in the Make Ready program. (Tr. 386, 3965.) Through the program, the Company will work with customers to build out the infrastructure behind the meter for qualifying commercial and industrial customers to facilitate the installation of EV charging stations. (Tr. 140, 373, 3964-65.)

All ratepayers will experience benefits from the expansion of the Make Ready program. (Tr. 462-63.) EV owners and commercial partners will experience the firsthand benefits of electric transportation infrastructure upgrades. In addition, the Company's Rate Impact Measure ("RIM") positive analyses evidence downward pressure on rates for all ratepayers. (Tr. 369-70, 377, 388; 3966.)

3. The Commission should approve the Company's requested Community Charging funding in support of Georgia Power's service as a provider of last resort in rural and underserved communities.

The Commission should also approve the Company's requested Community Charging funding because it supports expansion of the state's EV charging infrastructure, helping make EV ownership and usage more accessible to Georgians. With only approximately 3,000 EV charging plugs across Georgia, large swaths of the state's rural and economically challenged communities do not have sufficient access to EV charging infrastructure, leaving countless Georgians without the ability to adopt EVs as a primary means of transportation. (Tr. 950.) The Company's proposed Community Charging investment will allow it to reach underserved communities by installing chargers of last resort along statewide travel corridors without impacting existing competitive charging markets. (Tr. 370, 428-29, 460; 3965.) Presently, Georgia Power owns 59 EV charging locations through the Community Charging program, representing only 3% of Georgia's EV charging infrastructure. (Tr. 951.) The Company's proposed investments in the Community

Charging program will support areas of the state without sufficient access to EV chargers by deploying an additional 33 locations over the next three years. (Tr. 967; 4088.)

F. The Commission Should Reject PIA Staff's Proposal to Gut the Grid Investment Plan by Removing Capital Dollars for the Transmission Plan and Removing 85% of the Investments for the Distribution Plan.

Georgia Power's Grid Investment Plan, approved by the Commission in the 2019 base rate case, is a 12-year program that focuses on improving distribution reliability and replacing aging transmission assets. (Tr. 244.) The Commission previously approved the Company's request to invest $1.3 billion for the 2020-2022 period. (Tr. 244.) In the current case, the Company requested approval of dollars associated with the next three-year period of the Grid Investment Plan. (Id.) The Grid Investment Plan continues to focus on distribution investments that will improve reliability for customers and transmission investments to replace aging system assets. (Tr. 245.) Ignoring the need for the critical investments addressed by the Grid Investment Plan, PIA Staff asks that this Commission reverse course and (1) reject all transmission investments planned for the next three years, and (2) remove 85% of the planned distribution investments. (Tr. 1558, 1582, 1584.) The Commission should reject this extreme recommendation, which is unreasonable, unsupported by the record in this case, and contrary to the best interests of customers.

1. The Commission should reject PIA Staff's recommendations concerning the transmission portion of Georgia Power's Grid Investment Plan.

As outlined in the 2019 Rate Case and again in the current docket, the transmission portion of the Grid Investment Plan focuses on replacing aging assets that have or will exceed their Company expected life by the end of the Grid Investment Plan period. (Tr. 337, 3983.) Company Witness Robinson provided robust testimony explaining that Georgia Power's transmission equipment installed during the 1950s, 1960s, and 1970s, is now approaching 50, 60, and 70 year lives. (Tr. 342-43, 4069-70.) Due to the large percentage of transmission equipment that is beyond or nearing its Company expected life, Georgia Power carefully designed the Grid Investment Plan to target the replacement of these assets to prevent transmission system reliability deterioration across the electric system. (Tr. 3983.) Based on the Company's extensive operational experience, the likelihood of failure for the transmission assets included in the plan will exponentially increase

as the assets age beyond their expected life. (Id.) If Georgia Power does not continue making these necessary investments in its transmission system, the reliability of the electric system will be negatively impacted due to increased failures related to aged transmission equipment. (Id.) Such failures can be catastrophic and simultaneous in nature. (Id.) Replacing these aged assets will (1) reduce the number of emergency failures, (2) mitigate system operation reliability concerns, and (3) avoid higher maintenance and replacement costs. Further, these investments will help ensure the safety of the general public and the Company's employees. (Tr. 3983.)

a. The Company is not "prematurely replacing" transmission equipment in the Grid Investment Plan.

PIA Staff Witnesses Alvarez and Stephens mischaracterize the Company's Grid Investment Plan strategy for the replacement of aged transmission assets as "premature equipment replacement." (Tr. 1558.) Importantly, the Company relied on its extensive operational and maintenance experience, outage and failure history, and ability to extend the expected life of its transmission assets to determine the age at which it should replace the transmission assets within the Grid Investment Plan. (Tr. 3986.) The Company also reviewed, analyzed, and compared its replacement assumptions against industry expected life ages for the transmission equipment identified for replacement in the Grid Investment Plan. (Id.)

As the Company testified during direct hearings, the Company used the bathtub curve to explain equipment failure rate variation over time. (Tr. 333-34.) Witness Alvarez and Stephens' testimony presented a bathtub curve based only upon the *estimated useful life* of a hypothetical piece of equipment. (Tr. 1572.) In contrast, Georgia Power based its bathtub curve on the *Company's expected life* for specific Georgia Power transmission assets. (Tr. 3982.) The life expectancy of Company equipment is supported by internal maintenance procedures, past experiences, equipment specifications, and equipment monitoring. (Tr. 3986.) Importantly, estimated useful life and expected life are two very different terms. (Id.)

Witnesses Alvarez and Stephens misrepresent the point at which the Company is replacing transmission equipment as part of the Grid Investment Plan. (Tr. 3987.) They assume the Company is replacing equipment in the middle of its estimated useful life bathtub curve, whereas the Company is actually replacing equipment in the "end-of-life period" where failures occur at an exponential rate due to age-related degradation of equipment. (Id.) To be clear, the Company is

strategically targeting transmission projects within this "end-of-life period" to prevent customer outages, avoid unplanned and catastrophic equipment failure, and better manage replacement costs for the benefit of customers. (Id.) The result, from both a reliability and cost perspective, would be worse if the Company waited until this aging equipment failed to replace it. Replacing transmission equipment after catastrophic failure costs 2 to 13 times more than strategically replacing this equipment through the Company's Grid Investment Plan. (Tr. 338, 3987.) The Company has presented the next three years of transmission projects within the Grid Investment Plan to strategically replace equipment that will have exceeded its Company expected life by the end of 2031 in the most coordinated and cost-effective manner, which is in the best interests of customers. (Tr. 3983.) Therefore, the Commission should reject PIA Staff's mischaracterization of the transmission portion of the Grid Investment Plan and approve the Company's plan as presented.

b. The Company employed objective approaches for identifying aging transmission assets that warrant replacement as part of the Grid Investment Plan as recommended by PIA Staff Witnesses Alvarez, Stephens, and Rana.

PIA Staff Witnesses Alvarez and Stephens assert that the transmission portion of the Grid Investment Plan should be based on objective approaches and diagnostic testing rather than simply on asset age. (Tr. 1558.) However, they ignore that the Company used objective measures and relied on its long history of robust maintenance practices, internal experience, and extensive operational knowledge to identify which transmission equipment to replace as part of the Grid Investment Plan, including preventive and diagnostic testing. (Tr. 3982.) To that end, Georgia Power incorporated this experience into its recommendation to replace transmission equipment that will be beyond the Company expected life by the end of the Grid Investment Plan period. (Id.) Notably, through its comprehensive maintenance practices, the Company has already extended the life of this transmission equipment beyond its industry expected life. (Id.) For example, while the industry expected life for transformers and breakers is 35 years and 25 years, respectively, the Company's expected life for transformers and breakers is 50 years and 35 years. (Id.) Accordingly, the Company has already adopted and implemented the objective approaches that PIA Staff recommends in identifying the proposed transmission investments in the Grid Investment Plan.

Further, the Commission should ignore Witness Stephens' isolated example of a single 99-

year-old transformer on Georgia Power's system. (Tr. 1735, 3984.) This isolated example should not be used as a basis for assuming that the Company's entire transformer fleet can or should operate that far beyond Company expected life. As shown in the Company's rebuttal testimony, the percentage of transmission and distribution substation equipment within 10 years of the oldest vintages for such equipment on Georgia Power's system represents only approximately 2% of each equipment category, with power transformers being less than 0.2%. (Tr. 3985.) Georgia Power acknowledges that a small portion of substation equipment can operate well past Company expected life. (Id.) However, this is the exception to the rule and the overwhelming majority of Georgia Power's transmission and distribution assets should not be expected to operate safely and reliably for this long. Over the last 10 years, Georgia Power substation transformers have failed at an average age of 43 years, which is already past the industry expected life of 35 years, but earlier than the age of 50 years at which this equipment will be replaced within the Grid Investment Plan. (Tr. 3983.) Given the large number of transmission assets that will exceed their Company expected life in the near future, replacement of these assets through the Grid Investment Plan is the appropriate solution, and better for customers and the transmission system than simply operating these aged assets for an unknown period of time until they fail. (Tr. 3985-86.)

Finally, contrary to Staff Witnesses Alvarez, Stephens, and Rana's overreliance on inspection and performance testing for determining when equipment should be replaced, routine diagnostic testing and inspections cannot always accurately predict when equipment will fail. (Tr. 3982-83.) As Witness Robinson testified, of the 196 substation transformers that failed in-service over the last ten years, 108 (55% of these transformers) failed after passing such diagnostic tests and inspections. (Tr. 3983, 4058, 4060.) The Company's extensive operational experience informed its recommendation to replace transmission assets that have or will exceed their Company expected life by 2031 through the Grid Investment Plan rather than solely relying on the results of the Company's routine diagnostic tests and inspections. Therefore, the Commission should give little weight to the arguments of PIA Staff Witnesses Alvarez and Stephens in their attempt to discredit the Company's strategic and thoughtful plan for transmission asset replacement.

c. A cost benefit analysis for the transmission portion of the Grid Investment Plan is not practical or necessary for the Commission to approve the Company's request in this case.

Witnesses Alvarez and Stephens also argue that the Commission should not approve any transmission Grid Investment Plan funding in the absence of a cost benefit analysis. (Tr. 1587, 1746.) As explained repeatedly by the Company in this case (and in the 2019 Rate Case), it is impractical to perform a cost-benefit analysis for transmission investments included in the Grid Investment Plan due to the dynamic and networked nature of the transmission system. (Tr. 3984, 4067-68.) Several factors impact transmission system operation and could change suddenly in any such cost benefit study, including system loading and flows, facility and generation outages, and weather. (Tr. 3984.) The ability to conduct a meaningful and accurate cost-benefit analysis of transmission investments in the Grid Investment Plan is further complicated by the type of failure that could occur (controlled or catastrophic), impacts to other capital projects, lead times for replacement equipment, and the cost of generation redispatch due to loss of transmission elements. (Id.) The constant change in these variables would produce a cost-benefit analysis with unreliable conclusions that could be rendered obsolete or invalid at any given time. The results of such analysis would be questionable, at best. (Id.) For these reasons, the Company used asset age to determine capital investment in each transmission facility to mitigate the risk of outages associated with a significant and growing number of assets that are approaching or have exceeded their Company expected lives. (Id.) Thus, even if the Company were to prepare a cost benefit analysis, it would not provide the Commission meaningful information on which to rely. Therefore, yet again, the Commission should dismiss PIA Staff's attempt to undermine the Company's Transmission Grid Investment Plan request.

2. <u>The Commission should reject PIA Staff's recommendation to gut the distribution portion of the Grid Investment Plan by removing the undergrounding and basic insulation level investment packages</u>.

The Company's proposed undergrounding and Basic Insulation Level ("BIL") investment packages should not be removed from the Grid Investment Plan. If it were to eliminate these investment packages, the Commission would eliminate 85% of the planned distribution investments included in the Grid Investment Plan—essentially forestalling the purpose of the

distribution portion of the Grid Investment Plan, which focuses on ensuring lasting reliability improvements while minimizing the total cost to customers. (Tr. 3989.) In addition, the Company disagrees with PIA Staff Witnesses Alvarez and Stephens' assertion that "there is no pending reliability emergency." (Tr. 1565, 1567, 3989.) Georgia Power's system reliability will continue to worsen every year that investments are not made. Between 2013 and 2021, the Company's system average interruption duration index ("SAIDI") worsened by approximately 44% and system average interruption frequency index ("SAIFI") worsened by approximately 10%. (Tr. 3989.) For a subset of feeders (also referred to as circuits) in the system, and the customers on those feeders, the decline in reliability is even more pronounced. This worsening reliability has significant negative impacts on customer experience due to more frequent and longer outages, as well as increases in the economic cost incurred by customers. (Tr. 3989-90.)

Removing the undergrounding and BIL investment packages from the Grid Investment Plan would result in significantly longer and more frequent outages across the system, as these two packages are the most effective way to permanently address the root causes of outages on the nearly 400 feeders selected for these investment packages. (Tr. 3990.) Without these investments, the Company would achieve an end-state SAIDI of approximately 127 by 2031, essentially equal to the program starting point SAIDI in 2019, compared to the Grid Investment Plan's current projected end-state of approximately 80. (Id.) The results of PIA Staff's recommendations would maintain the system-level SAIDI at third quartile levels and stall reliability improvement opportunities. (Id.) As such, the Commission should reject PIA Staff's proposal to remove the undergrounding and BIL packages from the Company's Distribution Grid Investment Plan.

a. The Grid Investment Plan is a dynamic multiyear effort that the Company should appropriately revise as lessons are learned, not abandon simply because circumstances change and early results reveal more efficient future options.

Witnesses Alvarez and Stephens criticize the Company's revised SAIDI target from 65 as filed in the 2019 Rate Case to 80 in the 2022 Rate Case. (Tr. 1563.) They claim that 23.1% deterioration in target system SAIDI after only three years "calls into question the Company's projection of the actual performance improvement customers will receive for very large capital investment made by Georgia Power." (Id.) In reality, the revision to the end-state SAIDI targeted in the Company's Distribution portion of the Grid Investment Plan is a result of lessons learned

from the first three years of implementation and not a reflection of changed reliability expectations. (Tr. 3990.) In fact, the Company has seen better than expected reliability improvements from the set of investments that have completed construction. (Id.) Initial results indicate an improvement of approximately 65% in both SAIDI and SAIFI for Grid Investment Plan projects that have been completed for over a year and cycled through both a winter and summer peak since completion. (Tr. 3990-91.) The investments are working as intended and are delivering improved reliability for Georgia Power's customers. (Tr. 3991.)

Based on insights and lessons learned in the first three years of the program, Georgia Power confirmed the following: (i) that the overall strategy and economic rationale supporting the Grid Investment Plan is optimal for customers; (ii) the total cost required to deliver individual investments is higher than originally projected because of increases in scope and cost of work (e.g., inflation, COVID shortages); and (iii) while undergrounding remains the most effective solution for improving customer reliability, the use of undergrounding should be carefully evaluated to ensure it is used only where it is the most cost efficient solution. (Tr. 3991.) With these learnings, the Company appropriately reassessed and refreshed the distribution portion of the Grid Investment Plan, employing the same methodology used in the 2019 Rate Case, to ensure that the investments being made continue to result in the lowest total cost to customers. (Id.) As a result of this evaluation, the Company determined that the set of distribution investments in the best interests of customers are projected to deliver an 80 end-state SAIDI as compared to the 65 end-state SAIDI included in the 2019 Rate Case plan, which are still first quartile results compared to industry peers. (Id.) The Company considers this intermittent refinement of the 10-year Grid Investment Plan essential for ensuring that customer capital is managed responsibly. (Id.) The outcome of these refinements is a distribution plan that continues to deliver, where it is economically beneficial, strong reliability benefits for customers.

b. The distribution portion of the Grid Investment Plan appropriately addresses feeder level issues through system level optimization.

The Company's distribution portion of the Grid Investment Plan optimizes benefits at the system level rather than the feeder level because the cost of system reliability is borne by all customers served by Georgia Power. (Tr. 3992.) In other words, the cost for capital investment and ongoing O&M expense for the grid is paid for by all customers, regardless of each customer's

reliability experience and regardless of whether the customer's individual feeder is included within the Grid Investment Plan. (Id.) The Company intentionally chose to optimize benefits across the system to ensure the investments made were in the best interest of all customers instead of just the subset of customers served by an individual feeder. (Id.)

Staff Witnesses Alvarez and Stephens recommend that the Company conduct a root cause analysis for every feeder on the Company's system (Tr. 1608), which implies that the Company has not done such analysis. That is a misconception. Each and every distribution investment within the Grid Investment Plan is evaluated on a feeder-by-feeder basis with a root cause analysis. (Tr. 3992.) The Company does exactly the level of analysis suggested by Staff Witnesses Alvarez and Stephens. The initial 'hurdle' for any feeder to qualify for investment is that the feeder has had sustained poor performance over the past five years. (Tr. 3993.) The Company then undertakes a second evaluation to determine the root causes of outages on each feeder to determine if the outages were a result of vegetation, vehicles, animals, or weather and how that compares to the rest of the system. (Id.) An evaluated feeder qualifies for a distribution investment package that would permanently resolve the outage cause(s) only if it experiences a higher percentage of outages driven by the particular cause(s) than the system average. (Id.) In this way, the Company deploys standard, repeatable criteria systematically across all feeders to identify outliers in each category of outage cause.

Therefore, prior to optimizing the plan, the Company has completed a feeder-by-feeder, root cause analysis on the entire distribution system. (Tr. 3993.) Through this analysis, the Company determines whether a feeder should be considered for any investment and, if so, which of the six possible investment options specifically would address the root causes of reliability issues on that feeder. (Id.) For each of the possible investment packages identified during the root cause analysis, the Company projects the costs and the reliability benefits specific to deploying qualified investment package(s) on each feeder. (Id.) The Company then evaluates the impact of all possible combinations of feeder level investments to determine the final investment plan that provides the best reliability and the lowest total cost to customers. (Tr. 3994.) As a result, the Company considers the direct cost of investments compared to the costs customers bear from increased outages if no investment was made. (Id.) Contrary to the allegations raised by PIA Staff, the Company appropriately considers feeder level costs and benefits prior to optimizing its

proposed distribution investments.

c. The Company's undergrounding and BIL investment packages offer cost effective and permanent solutions to systemic feeder level problems that cannot be addressed by greater vegetation management as proposed by PIA Staff.

PIA Staff Witnesses Alvarez and Stephens wrongly claim that increased vegetation management is an effective alternative to the undergrounding and BIL Grid Investment Plan packages. (Tr. 1602.) PIA Staff offered no independent analysis to validate their assertion. (Tr. 3995.) Though vegetation management has an important place in managing overall system reliability, it is a temporary solution that cannot address a variety of other outage drivers, such as vehicles, wildlife, and lightning. (Id.)

PIA Staff could not explain how vegetation management could generate the same expected level of reliability improvement as the dedicated investment packages included in the Distribution Grid Investment Plan. (Tr. 3995.) During cross examination, Mr. Stephens confirmed that no analysis had been done to determine how much it would cost to actually improve reliability through vegetation management. (Tr. 1874.) Mr. Stephens himself also acknowledged that he had merely made an assumption about vegetation management as a cost-effective alternative. (Tr. 1872-73.) Many activities fall within the category of 'vegetation management,' and Mr. Stephens did not complete any analysis to determine which activities specifically would need to be added or increased to obtain reliability improvements through vegetation management. (Tr. 1875.) Finally, Witnesses Alvarez and Stephens proposed a legislated expansion of utility rights of way as a potential approach to improving reliability. (Tr. 1605, 1877.) Mr. Alvarez confirmed at the hearing that he had not undertaken any analysis of how long it would take or how much it would cost to pass such legislation. (Tr. 1877-78.) As such, PIA Staff failed to demonstrate how its proposed alternatives to the Grid Investment Plan were either less costly or more beneficial than the Company's proposal.

In addition, Staff's assertions that the undergrounding and BIL packages are not cost-effective are unfounded. PIA Staff systematically underestimated investment benefits by not accurately representing the cost to customers of foregoing undergrounding and BIL. (Tr. 3994.) First, PIA Staff Witnesses Alvarez and Stephens did not account for the continued reliability degradation that customers would experience if feeders selected for undergrounding or BIL are

denied investment, underestimating the economic cost to customers of the increased outages. (Id.) Second, PIA Staff did not quantify the outage repair-related and vegetation-related O&M expenses that will be incurred if these feeders are removed from the Grid Investment Plan. (Id.) In contrast, the Company has taken extreme care to account for all costs and benefits that will be experienced by customers during the formulation of the Grid Investment Plan. The Company is confident that the distribution investments that are part of the Grid Investment Plan are in the best interests of customers, resulting in the greatest reliability benefits for the lowest total cost to customers.

d. The Company's Grid Investment Plan already encompasses the qualities of a Worst Performing Feeder Program as recommended by PIA Staff.

In searching for an alternative to the Company's Distribution Grid Investment Plan, PIA Staff proposes that the Company simply invest in a more robust "Worst Performing Feeder" Program. (Tr. 1620.) Such a program would include (1) clear and repeatable criteria to identify poor-performing feeders, (2) a dedicated budget and associated personnel to administer the program, and (3) standard tracking and reporting on the program's progress. (*See* Tr. 1608.) To be clear, the distribution portion of the Company's Grid Investment Plan already encompasses the key qualities that Staff recommends as part of its proposed 'Worst Performing Feeder' program.

First, as is presented in the Customer Benefit Analysis, the Company has clear and specific criteria for each distribution investment package in the Grid Investment Plan. (Tr. 3997.) This includes reliability-specific criteria (e.g., SAIDI, SAIFI), physical attribute-related criteria (e.g., overhead vs. underground), and criteria that identify the root causes of outages (e.g., outages due to vegetation or vehicles, feeder load). Where the root cause is unclear, not addressable, or cost prohibitive, an investment is not made. (Id.)

Second, the distribution portion of the Grid Investment Plan has a designated budget and designated personnel similar to what PIA Staff recommends. (Tr. 3998.) In the 2019 Rate Case, the budget for the first three years of the distribution portion of the Grid Investment Plan was approved by the Commission. Moreover, since 2019, the Company has established a team solely devoted to the Grid Investment Plan – from program and project managers, to engineers, supply chain personnel, and construction workers on the ground.

Third, Staff Witnesses Alvarez and Stephens recommend "standards for tracking spending, projects, and results." (Tr. 1608.) The Company rigorously tracks all spending for the Grid

Investment Plan (at both the project and program level), as well as the reliability performance of each Distribution feeder – before, during, and after investment. (Tr. 3998.) This fact is evidenced by the adjustments made by the Company in the overall plan and optimal range for investment. The Company also reports on the Grid Investment Plan performance during the Company's rate case and makes itself available to respond to any data requests on the Grid Investment Plan. (Id.)

Finally, Staff failed to conduct the analysis required to validate its recommendation that the Company should focus only on feeders that are performing 2.5 times worse than average as part of its 'Worst Performing Feeder' program. (Tr. 3996.) This lack of analysis is inconsistent with Witnesses Alvarez and Stephens' own assertions that grid investments should only be made if they are cost effective at the feeder level. PIA Staff did not consider the type of investment that would be required to address the root cause of outages on feeders that are performing 2.5 times worse than average. (Id.) For many of these feeders, undergrounding and BIL would be the best solution to address root causes – yet both are investment packages within the Grid Investment Plan that Staff recommends removing. The distribution portion of the Grid Investment Plan encompasses the very qualities that PIA Staff recommends should be part of the Company's 'Worst Performing Feeder' program and will provide key reliability benefits in a cost-effective manner for the benefit of customers. Therefore, the Commission should approve the distribution portion of the Grid Investment Plan as proposed by the Company, without modification.

G. To Appropriately Integrate Additional Distributed Energy Resources ("DER") to the System, the Commission Should Approve the Company's Requests for DERMS and Improved Communication and Visibility Requirements.

1. The Company must invest in DERMS to optimize the benefits from increased DER penetration on the system.

PIA Staff proposes to reject DERMS spending until the level of DER on the grid increases and claims that existing systems and processes can manage DER. (Tr. 1625-26.) While current software systems allow for the monitoring of power flows and equipment status, they lack the enhanced monitoring and operational capabilities of DERMS that are necessary to allow for the optimization of an electric system that takes full advantage of the proliferation of DER. (Tr. 212, 259-60, 3999.) The systems currently in place cannot manage the substantial number of DER expected to connect to the electric grid in the coming years. As more DER are added to the system,

it is essential that the Company have visibility, predictability, and control (where applicable) of these resources. Failure to do so could compromise the Company's ability to accurately forecast and optimize the full array of generation resources and could negatively impact power quality and reliability. (Tr. 3999.) Further, current software systems do not allow a system operator to process the significant amount of data coming in from DER or make informed decisions quickly enough to optimize grid operation. (Id.)

In contrast, a DERMS that is fully integrated with the Company's other grid control systems will allow the Company to continually optimize larger portions of the grid and address a variety of constraints, such as economic dispatch, Volt/VAR optimization, and reliability. (Id.) Additionally, DERMS will allow the Company to consider demand side resources alongside supply side resources in future IRPs, as ordered by the Commission in the 2022 IRP. The Company's implementation of DERMS at this point will also allow for maturation of the DERMS solution as thousands or tens of thousands of additional DER are connected to the grid. If DER growth continues unrestricted without the installation of DERMS, the Company risks a loss of grid control, which would compromise grid reliability and stability. (Id.) A DERMS solution is a natural, logical, and necessary step for the Company to prepare for the growth and integration of variable and distributed energy resources.

To reiterate, there are significant risks to grid stability if the Company were to delay implementing DERMS. (Tr. 4000.) Beginning implementation of a DERMS solution now allows for the full DERMS capabilities to be developed in parallel with increasing DER penetration across the electric grid. Further, the complexity of integrating DERMS with the Company's existing critical software systems will require a significant amount of time. Undertaking DERMS over the next three years reduces the risk of restricting DER interconnections in the future because of a lack of DER forecasting, control, and optimization capability. (Id.) The Commission should approve the Company's requested funding for DERMS in this case to optimize the integration of DER on the Georgia Power system.

2. Improved communications interfaces with customer generation systems will enable the Company to safely and reliably integrate DER operating in parallel with the system.

Contrary to the arguments posed by PIA Staff Witnesses Barber, Deitchman, and Watkins

(Tr. 2195), the Company did not propose edits to Section G of its Rules and Regulations to require unconditional access and control of customer generators. Rather, the Company proposed requiring that the customer generation facilities interconnecting to the Company's electric system include a communications interface, installed and maintained by the customer, that supports information exchange with, and control by, Georgia Power so that the Company may continue to operate the electric system in a safe, reliable, and efficient manner. (Tr. 4000.)

The proposed requirement to allow for communication and increased DER visibility is critical to maintaining the system's safety and reliability. Without visibility, it is impossible for a utility to ascertain the status, availability, real time actual output, and forecast availability of a resource. Without control, it is impossible for a utility to update functional settings such as active power setpoint, frequency response, and reactive power modes in response to real time grid conditions. (Tr. 4001.) These functions enable real time economic optimization of the electric grid. The Company is requesting that all existing and future customer generation facilities be equipped with a local communications interface so that these facilities will be available to the Company's eventual DERMS solution. Without visibility and control capability on existing customer generation facilities, the Company cannot be fully aware of the interaction of those facilities with other generation facilities and the rest of the electric grid. (Id.) As the number of distributed generators grows, the ability to communicate and potentially interact with customer generation will allow for additional growth that might not otherwise be possible. Therefore, the Commission should approve the Company's proposed modifications to Section G of its rules and regulations.

H. The Company's Residential Rate Design Recommendations are in the Best Interests of Customers and Should be Approved by the Commission.

1. PIA Staff's proposal to eliminate the declining winter rate structure is unnecessary.

The Company originally designed the residential rate to reflect the seasonality of costs to serve residential customers. (Tr. 4236.) The increasing price blocks in June through September reflect the fact that the Company's costs are higher in the summer months. (Id.) The increasing price structure provides incentives for energy efficiency and conservation. The Company is projected to remain a summer peaking utility and the inclining rate in the summer months and the declining block structure in the non-summer months supports that. (Id.) Further, the declining

block structure in the non-summer months recognizes that off-peak costs are lower and provides price signals to reflect this reality. (Id.) The declining block structure provides an economical option for customers choosing to use electric-based heating. The prices are set to more than cover the Company's marginal costs and resulting revenues place downward pressure on rates for all customers. (Id.) The Commission should continue to reject requests to change the declining block rate structure as it has in the last two rate cases.

2. Closing the 'R' Rate to new residential premises is an appropriate and gradual first step toward modernizing the Company's rate offerings.

The Company's proposal to close the R rate for new residential premises effective January 1, 2023, should be approved. This proposal is a logical step in the transition to more modern rate structures with price signals that more accurately reflect the cost of electric service for customers. (Tr. 4237.) To be clear, if the R rate is closed to new premises, customers will still be able to choose from among any of the Company's residential rate options for which they qualify, including Time of Use – Residential Demand ("TOU-RD"); Time of Use – Plug-in Electric Vehicle ("TOU-PEV"); or PrePay. (Tr. Id.) After the initial year of service at those new premises, customers will be eligible for two additional rates, FlatBill and Pay by Day. (Id.)

3. TOU-RD is an appropriate default rate for new premises.

a. Customers can understand the TOU-RD rate.

PIA Staff wrongly asserts that customers cannot understand the TOU-RD rate. (*See* Tr. 2179.) Customers can understand that if pricing is higher during certain hours, they can shift their energy usage to hours during which prices are lower to save money. (Tr. 2893.) Customers are also fully capable of understanding that under a demand rate they can save money by not running major appliances at the same time. As analogized by GIPL Witness Barnes, rooftop solar customers can understand that to save money they can run their higher demand appliances during daylight hours when their behind the meter ("BTM") systems are generating power in order to offset their own usage demand rather than purchasing that energy from the Company at a higher price. (Tr. 4647.) Similarly, rooftop solar and non-rooftop solar customers alike can understand the savings recognized by shifting their energy use to times of the day when energy costs less and

avoiding running major appliances at the same time.

Additionally, customers who have enrolled on the TOU-RD rate have remained on the rate for several years, which indicates that they understand and are satisfied with the rate. In fact, customer surveys reflect that TOU-RD customers are more satisfied and feel more knowledgeable about behavioral changes they can make to reduce their energy bills than customers on the R rate. (Tr. 4237-38.) Further, if customers have questions about the Company's rates, Georgia Power's team at the customer care center is available to help them understand how each rate option works, and the Company provides information directly to TOU-RD customers, in addition to making available helpful videos on the Company's website. (Tr. 4261-62.)

b. The TOU-RD Rate is not more costly for customers than the R rate.

The TOU-RD rate is not designed to cost customers more than the R rate; rather, the TOU-RD rate is designed to be revenue neutral for the average customer – meaning that the average customer would pay approximately the same annual bill amount on the TOU-RD rate as they would on the R rate. (Tr. 4238.) In fact, because TOU-RD provides better price signals to customers, they can make more informed decisions about their energy use and save on their electric bills by shifting usage to off peak periods and staggering the use of key appliances. (Id.) As a result, customers receive more efficient economic signals regarding their usage and energy choices. (Id.)

As new premises are added to Georgia Power's electric system, it can take anywhere from one to two years for the premises' monthly usage to normalize. (Id.) This ramp-up period could be due to numerous factors, including the timing of home construction, installation of appliances, or occupancy. At least one intervening witness commented during their direct testimony that the TOU-RD rate is an effective rate for customers that demonstrate a "good load factor." (Tr. 4788.) By allowing new premises to mature towards a normal usage level, customers at these new premises will greatly improve their load factors and have a better bill experience when comparing TOU-RD to the R rate. Because the bill comparisons that PIA Staff highlights in testimony represent premises that are new to our system, the average monthly usage for those premises is far below the level at which the usage will ultimately mature. (Tr. 4238.) Therefore, the bill comparisons used by PIA Staff are heavily skewed by extremely low usage and fail to tell a

complete story.

c. TOU-RD is less volatile than the TOU-REO rate.

As a default rate for residential customers, the Company recommends using the comparatively less volatile rate, TOU-RD. The TOU-RD rate is much more stable than either TOU-REO or the 'R' Rate when comparing the difference between minimum and maximum bills over a given year, as shown in Figure 2 of the rebuttal testimony of Lee Evans and Larry Legg. (Tr. 4240.) Recognizing customer interest in bill stability, the Commission should adopt the Company's recommendation to use TOU-RD as the new default residential rate if closing the 'R' Rate to new premises is adopted.

d. TOU-RD is more cost reflective than the R rate.

TOU-RD is a modern, three-part rate that sends price signals that more accurately and appropriately reflect the cost of electric service. Costs to serve customers are divided into three components: (1) customer-related costs; (2) demand-related costs; and (3) energy-related costs. To ensure our rates most accurately reflect the cost to serve our customers, all three cost components should be accounted for within the design of a rate. (Tr. 4239.) As such, three-part rates, which include customer, demand, and energy-related components, are the most cost-reflective rates because they appropriately account for each of the three cost categories. (Id.) Conversely, when a rate, such as the R rate, lacks a demand component, the demand-related costs of electric service must be recovered through the rate's energy component, which does not appropriately match the collection of revenues with how the Company incurs costs. The result is a less efficient price signal that leads to less efficient use of the electric system by customers and higher prices overall. (Tr. 4240.) Based on this reasoning, the Company supports customer movement to three-part rates such as TOU-RD. Because the TOU-RD rate provides better price signals than the R rate, customers can make more informed decisions about their energy use and save on their electric bills by shifting usage or staggering the use of key appliances. (Tr. 4233.)

I. The Company's Commercial Rate Design Recommendations are in the Best Interests of Customers and Should be Approved by the Commission.

The Company's commercial and industrial rates continue to be appropriately structured,

and the Company does not agree with PIA Staff and Intervenor proposed changes to these rates.

1. The Commission should deny PIA Staff's recommendation that customers on marginal rates be assessed the fully embedded cost of the ECCR tariff because such a change is contrary with how marginal rates like RTP are designed to operate.

Fully embedded costs are recovered from the Customer Baseline Load ("CBL") portion of the marginally priced rates, while marginal costs are recovered from the marginal portion of the rates. (Tr. 4233.) To include embedded costs such as ECCR in the marginal portion of rates like RTP, as suggested by PIA Staff (Tr. 2148), would undermine the rate structure and significantly decrease the appeal of the rate to current and future customers.

PIA Staff's recommendation is fundamentally inconsistent with how marginal rates like RTP are designed to operate. (Tr. 4241.) For RTP as designed, the Company's fully embedded costs are recovered from the CBL portion of the rate, while marginal costs are recovered from the marginal portion of the rate. (Id.) To include fully embedded costs such as ECCR in the marginal portion of the RTP rate would not only corrupt the rate structure, but also prevent these rates from functioning as marginal rates because the hourly prices would no longer reflect marginal costs or real-time prices. (Tr. 4241-42.) Moreover, the ECCR costs include coal combustion residual asset retirement obligations ("CCR ARO"), which are fully embedded costs incurred by the Company independent of a customer's kWh usage. (Tr. 4241.) As such, counter to recommendations by GIPL Witness Barnes (Tr. 2976) and PIA Staff (Tr. 2148), ECCR costs are appropriately recovered through the CBL portion of the rate.

If ECCR costs, or other fully embedded costs, were allocated to the marginal portion of RTP rates, RTP costs would increase by approximately $150 million overall. (Tr. 4242.) A cost shift of this magnitude would significantly decrease the appeal of the rate to current and future customers. The RTP rate is a critical rate for large, economic development customers that are considering locating, relocating, or expanding operations in Georgia. (Id.) PIA Staff's proposal undermines the principles of marginal rate design by dramatically altering the allocation of ECCR costs within the RTP rate and would have a significant negative impact on the Company's ability to help attract economic development opportunities to the state. (Id.) PIA Staff acknowledges the drastic nature of its proposal and offers to mitigate its own proposal by only shifting 50% of embedded costs to the marginal portion of the RTP rate. (Tr. 2148.) However, even an incremental

move of 50% would have a dramatic and negative impact on RTP customers by fundamentally changing the rate and undermining the core principles of a marginal rate structure.

2. The Commission should deny DOD Witness Blank's recommendation to modify the Company's criteria for the reduction of CBLs for customers who install behind the meter generation.

The Commission should reject DOD Witness Blank's recommendation to modify the Company's criteria for the reduction of CBLs for customers who install BTM generation because customer generation does not permanently remove the customer's load and does not justify the reduction of a customer's CBL. CBLs may be reduced when load originally represented in the CBL has been permanently removed. (Tr. 4242.) Generation does not permanently remove load, and therefore does not justify a reduction of the customer's CBL. (Tr. 4242-43.) Further, Mr. Blank misunderstands how the Company's back up service rate and RTP rates work. He incorrectly assumes that an RTP customer can also take service under the Company's Back Up Service rate simply because it has BTM generation on site. (Tr. 3404.) They cannot. (Tr. 4243.) This misunderstanding should not be used as a basis to make changes to how CBL reductions for RTP customers are calculated. The Commission should reject this recommendation.

Second, Mr. Blank criticizes the Company's requirement that a CBL reduction assessment based on historical load is not permitted unless the customer stops taking service under the RTP tariff for two years. (Tr. 3404-5.) The Company supports the requirement that a customer remain off the RTP rate for two years before returning or requesting a CBL reduction, because short term changes to a customer's usage should not result in the permanent conversion of embedded load into marginal load on the RTP rate. (Tr. 4243.) The RTP tariffs include provisions to revise the CBL as the result of actions like permanent equipment removal and energy efficiency improvements, but the tariffs specifically prohibit CBL revisions due to temporary factors such as economic downturns. (Id.) Requiring customers who have not removed load to stay off RTP for 24 months in order to set a new CBL preserves the integrity of the RTP program and protects other customers from potential cost shifts that might result from premature revision of the CBL. (Id.)

RTP customers can still benefit from installing onsite generation even in the absence of Witness Blank's recommendations. RTP customers that install and use generation receive the benefit of the Company's marginal price for that hour. (Tr. 4243.) This is true when the customer

avoids paying the marginal price while operating above their CBL level, or when the customer receives a credit at the marginal price when operating below their CBL level. (Id.)

3. The Commission should reject PIA Staff's recommendation to modify the terms and conditions of the Fixed Price Alternative ("FPA") and Price Protection Product ("PPP") offerings to remove Company discretion over when to offer these rates.

The Company considers multiple factors when deciding whether to offer the FPA rate and PPP offerings to customers. These factors include, but are not limited to, uncertainty around environmental regulation, fuel markets, and other potential factors that could impact the pricing of these offerings. Additionally, it is important for the Company to maintain flexibility to act quickly and update PPP offerings to best reflect market conditions, especially during times of fuel market volatility as have been experienced for the last year. As a result, removing the Company's discretion regarding when to offer these products adds unnecessary risk that could be borne by other customers, since delays in acting during volatile markets could result in the development of product offerings that do not properly reflect pricing impacts.

J. The Commission Should Approve the Company's Requested Block Prices for the Community Solar Program.

The Community Solar tariff offers qualifying customers the opportunity to support renewable energy and the development of solar power in Georgia by subscribing to a portion of the output from local solar facilities. (Tr. 888, 2184.) Every month, participating customers pay a fee for a subscription block of the energy produced by Community Solar facilities, and in return receive energy credits on their monthly bill that are based on the production from those facilities. (Id.) Additionally, the equivalent renewable energy credits ("RECs") are retired on the customer's behalf. (Tr. 888, 2184-85.)

The Company proposes to update the pricing for the existing residential Community Solar Charge from $24.99 to $27.99 per one kilowatt block to ensure that participants are not subsidized by non-participants. (Tr. 888, 928-29, 2185, 2299.) In addition, following the Commission's approval to expand the opportunity to participate in Community Solar to customers on the General Service ("GS") tariff, the Company has proposed that the pricing for GS Community Solar participants be set at $29.99 per one kilowatt block. (Tr. 888, 929.) The Community Solar

subscription price is designed to ensure that participating customers do not shift costs to other customers when kilowatt hours reduce the monthly bills of participating customers. (Tr. 939.) As such, the Company has requested an increase in its subscription rates for residential and commercial customers participating in Community Solar. (Tr. 914, 929.) Based on the approved structure of the Community Solar program, a reduction in the price per kW block of energy as proposed by several parties would leave costs unrecovered and, therefore, shift cost recovery to non-participants. (Tr. 914.)

PIA Staff's recommendation regarding the appropriate pricing for the Community Solar Program offers two alternatives and is premised on a Commission policy determination as to the purpose of the program: (i) if the purpose of the program is to support clean energy and realize bill savings, Staff recommends its $20 and $22 pricing for residential and commercial customers, or (ii) if the purpose of the program is to support clean energy but not the opportunity for bill savings, Staff supports the Company's proposed $27.99 and 29.99 pricing for residential and commercial customers, respectively. (Tr.2449-50.) PIA Staff's recommendations assume that this decision has not yet been determined. However, in the Commission's June 7, 2017 Order approving the Community Solar Program tariff, the Commission clearly stated that the Community Solar Program "is not designed to produce credits in excess of a customer's usage and a customer should anticipate the [Community Solar] program charges will exceed the value of any bill credits received."[6] Although PIA Staff may believe the purpose of the program is an open policy decision for the Commission, the Commission has already determined that the purpose of the program is not for bill savings. Rather, the Community Solar Program is targeted toward customers who are interested in supporting solar but either do not want or are unable to install solar panels at their premises. As such, the Commission should approve the Company's requested block price increase for the Community Solar program.

K. The Charge It Electric Vehicle ("CIEV") Rider is an Appropriately Structured, Time Limited Offering that Will Encourage EV Adoption and Should be Approved by the Commission Without Modification.

Georgia Power is supporting the rapidly expanding EV market with a rider that is tailored

[6] *Order approving Community Solar Program and CS-1 Tariff*, Georgia Public Service Commission, Docket Nos. 40161 and 16573 (June 7, 2017) at 2.

to provide affordably priced electric service and to encourage the growth of EVs in our state. (Tr. 407, 462, 2418.) The CIEV rider will modify how the Power & Light tariffs price commercial EV charging loads. (Tr. 886.) Specifically, the new CIEV rider will modify the monthly billing demands by using Billing Demand Adjustment Factors as specified in the tariff. CIEV is a temporary rider that will expire either at the end of 48 months or when the rolling 12-month load factor for the account reaches 15% or greater – whichever comes first. Participation is available to new, separately metered charging loads that are served on Georgia Power's system after January 1, 2023. (Tr. 930.)

The Commission should not open the CIEV rider to existing locations as recommended by AACE, ChargePoint, and EVgo. (Tr. 2310-11; Tr. 2418-19; Tr. 2521-22.) First, the CIEV rider was designed to incentivize the installation of new EV charging stations and opening this rate to existing customers would defeat the purpose of incentivizing new installations. Second, by limiting this tariff to new, separately metered premises, the Company designed the CIEV rider to avoid a cost shift among existing customers. If existing customers were permitted to participate on the CIEV rider, the reduced billing demand allocation in each year would necessarily shift demand costs to other customers. The Company does not support this cost shift and advocates that the CIEV rider should be limited to new, separately metered premises in order to appropriately incentivize new EV charging installations without doing harm to existing customers.

L. The Company's Cost of Service Study Reasonably Allocates the Company's Revenue Requirement Across Retail Rates Based on Principles of Cost Causation and Should be Approved Without Modification.

1. The 12-CP method is the most appropriate way to allocate the Company's production costs.

A 12-CP demand is defined as the sum of the highest kW load for the Company in each month of the 12-month period divided by twelve. (Tr. 892.) At the jurisdictional, class, or rate group level, 12-CP is the respective coincident demands at the time of the monthly system peaks. (Id.) Using this allocator ensures that the coincident load burden placed on the system by a jurisdiction, class, or rate group is allocated an appropriate share of the costs of the system. (Id.)

The Company's adoption of seasonal planning reinforces the appropriateness of the 12-CP approach. (Id.) The Company must plan to have sufficient generation to serve its customers in all

twelve months of the year and the 12-CP method appropriately captures the summer and winter peaks targeted through seasonal planning. (Id.) The summer and winter reliability planning of the Company further underscores that no one month or season is adequate at representing the coincident impact of customers on system capacity. (Id.) Georgia Power forecasts to remain a summer peaking utility. (Tr. 1061.) While the IRP identified winter reliability concerns, the Company's rate designs remain appropriate to address the forecasted peak loads and higher marginal costs that occur in summer months. (Id.)

In addition, as stated in Mr. Evans' Direct Testimony, the 12-CP allocation methodology has been used in every COSS study filed by the Company with this Commission since 1989. (Tr. 893.) The 12-CP method has been one of FERC's preferred allocation techniques for determining wholesale jurisdictional obligations, and it has been used by the Company in its filings before FERC. (Id.) It has proven to be a common and popular allocation technique employed in numerous retail filings before many state commissions throughout the United States. (Id.) It is a straightforward methodology, has a strong cost causative relationship, and has a history of providing stable and sound results. (Id.) The Commission should approve the Company's use of the 12-CP methodology for allocating production costs.

2. The Commission should reject PIA Staff and Intervenor proposals to adopt alternative production cost allocators.

PIA Staff argues that the shortcoming of the 12-CP method is that accurate load data is required by class throughout the year. (Tr 2109.) PIA Staff Witness Watkins admitted at the hearing, however, that the Company has an abundance of necessary data. (Tr. 2248.) Thus, the only shortcoming identified by PIA Staff to the Company's method does not hold true for Georgia Power.

In lieu of the 12-CP methodology, PIA Staff proposes to use the Base Intermediate Peak and Probability of Dispatch methodologies. (Tr. 2243.) However, adoption of these methodologies not only impacts the allocation of costs in base rate cases, but also may impact the allocation of fuel costs in the Fuel Cost Recovery docket. The trade-off between the level of Production fixed investment and the variable cost of producing a unit of output is one primarily made between base capital costs and fuel costs. Altering the allocation of Production capital costs with such a complex calculation would necessitate a similar alteration to the allocation in the Fuel Cost Recovery

docket. Recognizing the current, approved allocation of fuel costs in the Fuel Cost Recovery docket, the Company continues to support the 12-CP methodology as the most appropriate Production allocator. It has been employed by Georgia Power for allocating production capacity-related costs since 1989, and as such, has therefore influenced present rates. (Tr. 893.)

GSEIA, SEIA, and Vote Solar and GAM propose the Company use either a 4-CP or 6-CP production cost allocation methodology, arguing that as a summer peaking utility, the four summer months June through September drive the Company's peak demand and should be the basis for allocating the Company's production costs. (Tr. 3215; Tr. 3217; Tr. 3230.) In reality, the generation planning for Georgia Power's system is driven and influenced by non-summer periods in addition to summer peaks. Georgia Power utilizes Expected Unserved Energy ("EUE") in its determination of the optimal reserve margin for both summer *and* winter seasons. A pure summer peak or 4-CP allocator is an oversimplification of the Company's generation planning process. Using a pure summer peak allocator could create unstable, unbalanced, and inequitable cost allocation in which some rate groups receive little if any Production demand cost allocation whatsoever. An example of this could be if the pure summer peak allocator for that year occurred in daytime hours such that there was no subsequent cost allocation to outdoor lighting. The ongoing capacity needs of Georgia Power are heavily driven by winter needs and to not recognize or allocate costs based on winter loads would, therefore, be inappropriate. As such, the Commission should reject Intervenor proposals to modify the production cost allocation methodology and approve the Company's continued use of a 12-CP methodology.

M. The Commission Should Not Expand the Monthly Netting Pilot and Should Revise the RNR Tariff to Address the Negative Impacts to Non-Participating Customers.

The Commission should reject Intervenor arguments in favor of expanding the monthly netting pilot, even as a short-term interim measure to increase BTM solar penetration rates. As explained by Company Witnesses Evans and Legg, the Company's analysis identifies that the monthly netting pilot results in a substantial *additional* cost shift to non-participating customers above the baseline cost shift incurred by instantaneous netting under the RNR tariff. (Tr. 3719.) This additional cost-shift—while currently contained to only a subset of 5,000 pilot customers—will increase in both scope and severity were the Commission to adopt Intervenor recommendations to expand the monthly netting pilot. Further, PIA Staff and Intervenor proposals

for valuing excess energy "pushed back" onto the grid by BTM resources significantly exceed the value established by the Commission in the Renewable Cost Benefit ("RCB") Framework, which is appropriately based upon the Company's avoided cost.

In considering whether to expand the monthly netting pilot, the Commission should note that many other legislatures and commissions have found monthly netting to be a deeply flawed accounting construct that excessively compensates BTM solar resources. This excess compensation—while a boon to the solar industry—results in real and quantifiable harm to other customers. This harm increases exponentially at scale because as the amount of monthly netting customers grow, all other customers must shoulder an ever-increasing burden of the costs avoided by monthly netting customers. Conversely, instantaneous netting coupled with appropriate rate structures, such as three-part rates, will ensure that RNR customers receive appropriate price signals and compensation levels that encourage BTM solar development, while also preventing an inevitable and progressively significant cost shift that occurs under monthly netting.

While the Company's data suggests that the monthly netting pilot increased the rate of BTM solar adoption on the Company's system, this increase in BTM adoption resulted from an excessive subsidy that creates considerable additional expense for non-participating customers. Furthermore, since the closure of the monthly netting pilot to new customers, the Company has continued to receive new BTM applications at a rate close to that under the monthly netting pilot. With this trajectory in mind, and given the boost to the BTM solar market provided by the recently-enacted federal Inflation Reduction Act ("IRA") and other market trends decreasing the costs to install BTM resources, further subsidization of the BTM market through expansion of the monthly netting pilot is unnecessary and inappropriate.

1. <u>The Company's analysis confirms that monthly netting creates a disproportionate cost shift that increases rates for non-participating customers</u>.

Monthly netting does not adhere to fundamental rate design and cost-causation principles and presents two substantial flaws: (1) it compensates BTM customers at the Company's retail rate – which is much higher than the price the Company otherwise would pay for energy; and (2) it enables BTM customers to avoid paying their share of the costs to construct, operate and maintain the Company's electric system. This excess payment structure results in significant cross-subsidies that shift costs to non-participating customers.

As demonstrated by Company Witnesses Evans and Legg, a customer participating in the monthly netting pilot shifts an additional $287 of costs onto non-participating customers on an annual basis. (Tr. 5031.) When limited to the current subset of 5,000 pilot customers, the incremental aggregated cost shift associated with monthly netting equals approximately $1.4 million annually. If expanded to between 30,000-75,000 customers, as recommended by Intervenors, this cost shift would increase to approximately $8.6 million to $21.5 million per year. Moreover, including the $826 annual cost shift that already results from RNR customers receiving service under the Company's volumetric-based R tariff, this aggregate cost shift increases even further to approximately $24.8 million to $61.9 million per year. As the number of monthly netting customers grow, the costs that non-participating customers must pay to subsidize them will also grow. This increase compounds over time and has caused many states with aggressive monthly netting policies to reconsider and rebalance the interests of participating and non-participating customers in the interests of fairness underlying fundamental rate design and cost causation principles.

a. *Monthly netting customers rely upon and utilize the Company's system while avoiding cost responsibility.*

By netting an RNR customer's consumption of energy against the excess energy they export to the grid, monthly netting enables an RNR customer to receive a zero kilowatt-hour ("kWh") bill during a billing period. On a simple volumetric rate such as the Company's R rate, an RNR customer with a net zero kWh bill pays only the Company's basic service charge and applicable riders. This is notwithstanding that a substantial portion of an RNR customer's energy was supplied and delivered exclusively by the Company's system during the billing period. In this way, monthly netting allows RNR customers to fully use and rely upon the Company's electric system while avoiding contributing to the costs of the system.

As conceded by PIA Staff Witness Watkins during the hearing, RNR customers do not actually reduce their electricity consumption. (Tr. 4413.) RNR customers merely supplement Company-supplied energy with their own self-supplied generation during certain times of the day. An RNR customer's peak demand remains the same, with or without the BTM solar generation. Because the Company is obligated to serve the peak demand of all of its customers, including RNR

customers, the Company must plan for and be prepared to serve the RNR customer at all times, including when their BTM generation is intermittent.

Despite PIA Staff and Intervenor attempts to downplay this issue, the prevalence of net zero bills for RNR customers is material. Indeed, PIA Staff's Supplemental Direct Testimony Table 3 reveals that nearly 11% of monthly netting bills in 2021 resulted in net zero bills. (Tr. 4362, 4419.) Likewise, Table 4 of PIA Staff's Supplemental Direct Testimony similarly demonstrates that nearly 40% of RNR customers experience at least one month with a net zero bill. (Tr. 4363, 4419-20.) PIA Staff Witness Watkins counters that the excess energy contributed by the BTM solar generation fully compensates for the energy consumed by the RNR customer during the billing period. (Tr. 4415.) PIA Staff's argument, however, relies upon the assumption that the value of the customer's excess energy and the value of energy delivered by the Company's system are equal, which they are not. As testified by Company Witnesses Evans, Legg and Gattie (Tr. 3727-28, 3845), these values are not equal, and this false equivalence between imported and exported energy under monthly netting creates the cost shift revealed in the Company's analysis and acknowledged in other jurisdictions.

b. The Company's retail rate includes components that are not related to the cost of energy.

By netting their consumption against excess generation, RNR customers receive compensation for their excess energy at the full volumetric portion of the Company's retail rate. The Company's Commission-approved retail rate, however, recovers costs in addition to energy costs, including costs for transmission, distribution and other services included in the Company's cost of service. (Tr. 3726.) As evidenced by the multiple witnesses testifying on all of the cost of service issues in this proceeding, the Company's retail rates are inclusive of its total cost of service. This includes costs associated with the Company's other reasonable and cost-eligible expenses and investments required to provide safe and reliable electric service.

By contrast, the excess energy pushed back by RNR customers does not provide all these services, yet under monthly netting these customers receive compensation at the full volumetric portion of the retail rate. Unlike the Company's electric service, which provides all the services required to generate, transmit, and distribute energy to customers, BTM solar generators provide only marginal energy, which is why under the Commission-approved RCB Framework, this

energy is appropriately valued at the utility's avoided costs—the monetary value the Company saves by not having to generate this energy. Monthly netting is not part of the Company's revenue requirement calculation but is rather part of cost allocation and rate design. As such, it must be evaluated in accordance with cost causation and rate design principles, which inform how the Company's full revenue requirement should be recovered from customers. Multi-part rate designs are intended to ensure that RNR customers take service on a rate that is more reflective of their actual cost of service, thereby mitigating the cost shift to non-participants. Further, although PIA Staff argues that the Commission should ignore any cost shift because current rate design is not at parity, this does not provide a reasonable basis for further subsidizing BTM customers at the expense of all other customers. (Tr. 4358.) The goal of rate design should always be to reflect actual cost causation as closely as possible.

In lieu of recommending expanding the monthly netting pilot, PIA Staff lays out a range of possible compensation rates to be applied to the Company's current instantaneous netting customers. This range varies from approximately 6.99 cents to over 13 cents. Compensating BTM solar resources at such high levels, which are well beyond the Company's avoided costs, will further increase the cost shift to non-participating customers under the RNR tariff. As far as the Company is aware, these values provided by PIA Staff are not credibly tied to any quantification of actual benefit provided by the BTM resource, but rather represent a range of figures adopted from policy decisions made in other jurisdictions. This range of compensation rates is too arbitrary a set of variables to appropriately inform the level of compensation for BTM resources. The Company, PIA Staff, and several Intervenors have already undergone this analysis, in integrating BTM resources into the Company's RCB Framework. Rather than selecting an arbitrary compensation rate with the primary goal of incentivizing BTM resources, the Commission should adopt a default RNR tariff rate design structure which better reflects the cost to serve customers, such as the Company's TOU-RD rate. This rate is justifiable, cost-based, and is an appropriate step toward addressing the disproportionate cost shift associated with net metering and adopting a BTM solar program that fairly compensates BTM customers while protecting non-participating customers.

2. The Commission should not deviate from its deliberative and measured approach towards incentivizing renewable energy resources.

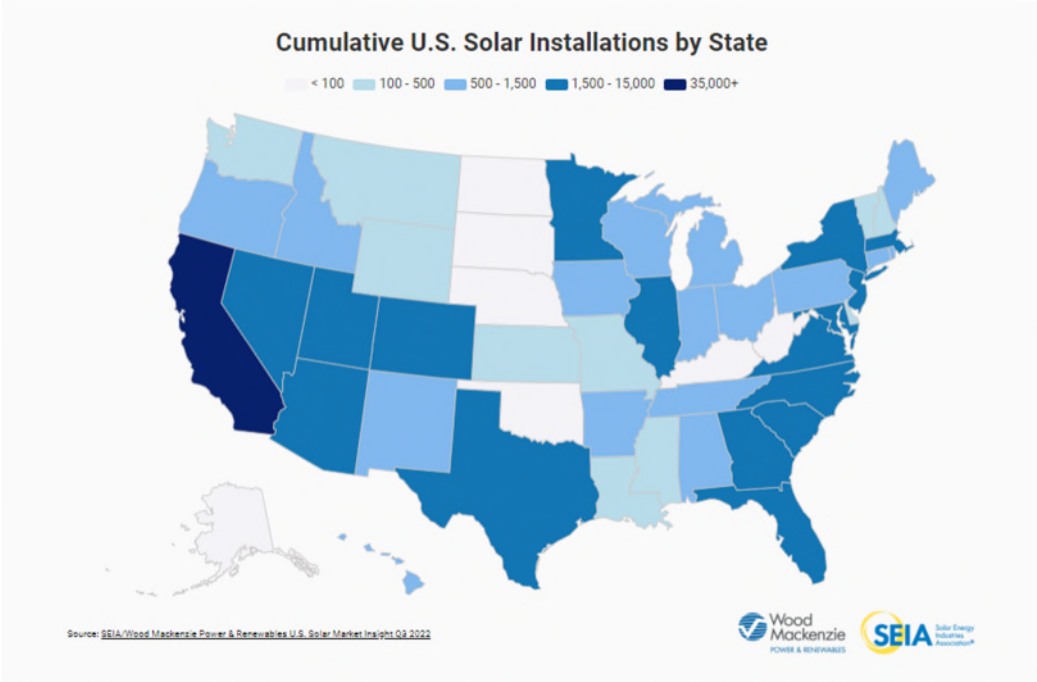
PIA Staff and Intervenors point narrowly to Georgia's BTM solar penetration rate as an indictment of Georgia's renewable energy policy, asserting that Georgia's BTM solar penetration ranking alone infers a need for this Commission to act and expand the monthly netting pilot. (Tr. 3876-3877, 4349-4350, 4383.) Relying on BTM penetration rates as the primary measure of success, however, discounts Georgia's considerable achievement in cost-effectively expanding renewable energy within Georgia without jeopardizing affordability for customers. As testified by Company Witness Gattie, this Commission's deliberate and measured renewable energy policy has enabled the state to deploy considerable amounts of solar generation while simultaneously retaining residential rates below the national average. (Tr. 3836-3839, 3847.) Through its thoughtful energy policy, this Commission has produced meaningful results for customers. The Commission should consider this record of accomplishment and continue the successful path it has created here in Georgia.

By holding BTM penetration rates as the sole measure of success, PIA Staff and Intervenors fail to consider that many states with higher BTM solar penetration rates have prioritized the development of BTM resources to the detriment of important considerations such as customer cost and system reliability. As explained by Company Witness Gattie, many states with high penetration rates of BTM solar have experienced significant negative impacts such as reduced system reliability, increased cost, and ratepayer fairness issues. Likewise, as noted previously, given overall market trends, Georgia is likely to see expanded BTM solar penetration, without additional subsidies or Commission action.

First, notwithstanding that the monthly netting pilot reaching its full 5,000 customer limit, the Company continues to receive only slightly fewer BTM solar applications each month in 2022 than received each month in 2020 before the pilot was launched. (Tr. 3716.) This level of growth post-pilot, without expanded monthly netting incentives, supports the Company's recommendations that this Commission need not introduce an additional subsidy for BTM resources. PIA Staff and Interveners have not provided credible evidence that the lack of monthly netting will significantly hamper growth rates. Such arguments also falsely cite to the existence of monthly netting as the sole variable limiting prior growth in BTM solar under the Company's

instantaneous netting program. These arguments ignore the significant reduction in the availability and cost for BTM solar facilities in the last few years and the growth of a robust solar installation industry—all of which have increased the availability and cost-competitiveness of BTM solar.

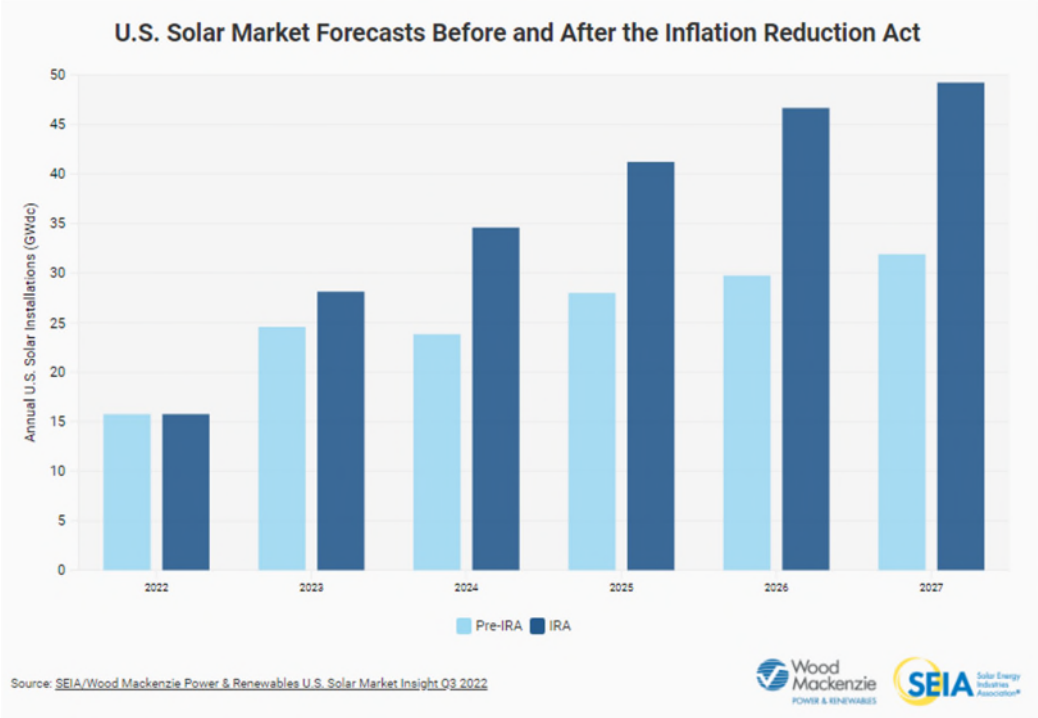
According to public information made available by SEIA, "[t]he cost to install solar has dropped by more than 60% over the last decade . . . [and] . . . has experienced an average annual growth rate of 33% . . .[t]hanks to strong federal policies like the solar Investment Tax Credit, rapidly declining costs, and increasing demand across the private and public sector for clean electricity . . ."[7] Also according to SEIA, and as noted in the below chart that identifies solar penetrations by state, Georgia's level of solar deployment is on pace with other states such as New York, Florida and Arizona:



Second, the recently passed federal IRA will significantly increase development in Georgia's BTM solar marketplace. GSEIA, SEIA, and Vote Solar go to great lengths to purposely downplay the benefits of the IRA. (Tr. 4403-4404, 4848-4853.) Despite characterizing as speculative and negligible Company Witness Gattie's conclusions regarding the wide-ranging

[7] Solar Energy Industry Association, Solar Industry Research Data, available at: https://www.seia.org/solar-industry-research-data.

benefits of the IRA and the IRA's likely impact on the solar market, GSEIA, SEIA, and Vote Solar have called the IRA "the most transformational clean energy policy in history" and have stated that "[t]he passage of this historic legislation has had an immediate impact [on the] long-term outlook for the U.S. solar industry." (Georgia Power Company Exhibit No. 44.) According to GSEIA "[t]he passage of the Inflation Reduction Act has drastically improved baseline projections for the solar industry over the next five years."[8] As projected on SEIA's publicly available webpage, the growth from the IRA will only build over time:



Notably, GSEIA, SEIA, and Vote Solar conditioned none of these statements on the availability of monthly netting. Instead, outside of their advocacy in this proceeding, these Intervenors have trumpeted the "transformative" impact on the installation of new solar capacity resulting from the IRA. Their attempts to downplay these same impacts on new solar capacity in this proceeding can only be described as self-serving.

By GSEIA, SEIA, and Vote Solar's own account, the IRA will have a monumental impact on the growth of solar in the United States and indeed in Georgia. GSEIA, SEIA, and Vote Solar's

[8] *Id.*

arguments that the IRA will not be enough incentive for Georgia's BTM solar market to grow is speculative and inconsistent with what they've said about the IRA elsewhere. All indications suggest that the IRA will significantly increase BTM solar development in Georgia. Expansion of the monthly netting pilot risks providing a too generous and unneeded subsidy to BTM solar at the expense of non-participating customers. Therefore, especially when considering the significant federal incentives that will come to Georgia from the IRA, the Commission should reject calls to expand the monthly netting pilot which provides an unnecessary subsidy for the BTM lobby at the expense of other customers.

Finally, SACE Witness Hill proposed the strawman argument that Georgia could miss out on IRA tax benefits if the Commission did not expand monthly netting. (Tr. 4448, 4484-85.) This is a baseless claim and is merely a transparent attempt to divert attention from the benefits already provided under the IRA. Nothing in the IRA requires that rooftop solar customers have access to monthly netting before availing themselves of the tax breaks under the IRA, and SACE has provided no evidence supporting this statement. Not a single Georgia customer will miss out on any tax credits under the IRA if they choose to install BTM solar. Georgia will have the same access to funds under the IRA as every other state. The IRA exists to provide financial incentives to private investment to achieve a specific policy goal and exists without regard to the availability of monthly netting.

3. The Commission should reject PIA Staff and Intervenor recommendations to recognize benefits not included in the Company's Renewable Cost Benefit Framework.

The Company has provided an exhaustive cost of service study in this case that includes the costs to serve all existing customers, including customers receiving service on the RNR tariff. Contrary to PIA Staff and Intervenor assertions, the Company considered all relevant, credible and quantifiable benefits provided by BTM solar in its analysis.

The Company has determined that approximately $21 in system benefits per customer accrue per year because of a customer's BTM solar generating facility. Despite the Company's quantification of these benefits, PIA Staff and Intervenors recommend the Commission recognize and include additional benefits not included in the Company's analysis, such as economic development, environmental and other externalities that are not included in the Company's cost of

service. For instance, SACE Witness Brown testifies that the Company should compensate RNR customers not only for excess energy, but for things such as lowering reliance on fossil fuels and expanded employment opportunities. (Tr. 4892.) As this Commission has recognized many times before, compensation for export energy should not include externalities that are not otherwise included in the Company's costs of service.

From as early as 1923 with the Bluefield decision, the United States Supreme Court defined the guidelines by which a regulator sets rates for a private utility. *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923). At its most basic, rates must be set to recover the utility's reasonable costs and earn a reasonable return. In other words, establishing rates relies on the utility's quantifiable amount of prudent investment and reasonable costs. Consistent with 100 years of law governing cost of service ratemaking, the Commission sets rates based on quantifiable costs associated with electric service and not indirect externalities.

Lawmakers and regulators can and do make policy decisions based on potential public benefits. But these policy decisions should not undermine the fundamental cost of service framework underpinning the way rates are established. Nor should these policy decisions create negative impacts for the Company's other customers. If the Commission chooses to further incentivize the penetration of BTM solar because of its intangible environmental and economic benefits, that decision must be grounded in a knowledge of the costs such a choice imposes on the Company and on the non-participating customers that will ultimately bear those costs.

4. <u>Other states are rejecting monthly netting due to significant cost shifts and non-participating customer impacts</u>.

Many legislatures and commissions that have recognized the negative externalities associated with monthly netting are now returning to avoided cost based methodologies as a replacement for monthly netting. As detailed by Company Witness Gattie, over the past several years, many states have reconsidered their net metering policies, primarily because monthly retail net metering overcompensates BTM solar resources at the expense of non-participating customers. (Tr. 3822-46.) Whether on the legislative or regulatory level, these states have targeted the very cost shift that the Company has highlighted in this case and changed their policies to mitigate the negative impacts caused by monthly netting. During the hearing, PIA Staff Witness Watkins

acknowledged this point, agreeing that the ". . . cost shift was certainly an element in each of those discussions . . ." (Tr. 4407.) While these states have employed different ways of describing this cost shift, they generally agree that it arises directly from compensating monthly netting customers at a rate equal to the retail rate for electricity, which overstates the actual value these resources provide to the grid and pushes fixed cost recovery onto other customers.

A poignant recent example can be found in California, where the California Public Service Commission ("CPUC") is reconsidering its existing net metering tariff in Docket No. R.20-08-020 ("NEM 3.0 Proceeding").[9] Much like the monthly netting pilot in Georgia, California's existing net metering policy provides customer-generators full retail rate credits for energy exported to the grid and requires them to pay a few charges that align NEM customer costs more closely with non-NEM customer costs. On November 10, 2022, the presiding administrative law judge issued a proposed decision recommending a move away from retail net metering. (Georgia Power Exhibit 43.) In doing so, the decision relies heavily on evidence that full retail net metering imposes a markedly unjust cost shift that requires remediation. As the CPUC notes, "[t]his cost shift is created by the ability of distributed generation customers to avoid fixed costs, including grid costs and public purpose program costs, which then become the responsibility of non-participating ratepayers, including low-income customers." (Id. at 4.) Moreover, the decision notes that this cost shift ultimately undermines the clean energy goals, including electrification: "[b]ut a cost shift exists, and continuation of the cost shift feeds into higher electricity rates, which discourage electrification." (Id. at 90.) It thus concludes, "[a]ccordingly, the successor tariff should address the cost shift not only to ensure equity but also to encourage electrification to ensure California can meet its climate and clean energy objectives." (Id.)

In its decision, the CPUC was especially concerned with the effect that such cost shifts had on low-income non-participating customers:

> The Commission agrees that the look-back study indicates that NEM 2.0 disproportionately harms low-income customers not participating in the net energy metering tariff. Findings in the look-back study show that NEM 2.0 and, thus, NEM 1.0 disproportionally benefited non-CARE residential net energy metering customers while all customers, including those with lower incomes, must bear the

[9] *See* California Public Utilities Commission, Net Energy Metering, NEM Overview, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/net-energy-metering

> addition of the 82 to 91 percent of the cost of service bypass by net energy metering customers. The Commission finds the look-back study indicates that NEM 2.0 disproportionately harms low-income customers not for participating in the net energy meeting tariff.

Indeed, when presented with this evidence from California during his November 29, 2022 hearing testimony, Intervenor Georgia Coalition for Local Governments Witness Hill, while distinguishing the level of solar penetration in California from Georgia, conceded that cost-shifting was an issue which Georgia would eventually have to address concerning its net metering program. (Tr. 4508.) ("This -- the level of cost shifting and dealing with monthly net metering at some point, I don't dispute that that's a good idea."). Moreover, he sensibly admitted that Georgia could and should draw lessons from the policy decisions of other jurisdictions, such as California:

> Q And I assume, Dr. Hill, that you don't oppose learning from lessons learned in some other jurisdictions; correct?
>
> A No. Absolutely.
>
> (Tr. 4511.)

While California is perhaps the most notable and recent state to reverse course on monthly netting, California is not the only state coming to this conclusion about the cost shifts inherent in retail net metering. In January 2017, in Decision No. 75859, the Arizona Corporation Commission ("ACC") eliminated retail net metering within the state.[10] In so doing, it similarly relied on demonstrable evidence that retail net metering inflicted costs on non-participating customers. The Commission noted, "[w]hile we refrain from commenting on the appropriateness of any particular rate design as part of this proceeding, the Commission is committed to modifying residential rate design in a manner that mitigates the recognized cost shift caused by rooftop solar customers' self-consumption."[11] Similarly, the Louisiana Public Service Commission, in its Order dispensing with retail net metering, endorsed its staff's analysis that, "[t]o the extent that the solar customers are

[10] Opinion and Order, *In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation,* Arizona Corporation Commission, Docket No. E-00000J-14-0023 (Jan. 3, 2017).

[11] Id. at 175.

paid any more than avoided costs for the energy they produce and sell to the utility, all of the non-solar customers must make up the difference."[12]

To remedy this cost shift, many of these states have elected to replace net metering with a compensation regime based on avoided-cost methodologies. In Indiana, Gov. Eric Holcomb signed a bill (SA309) in 2017 that put the state on a path to phasing out retail net metering by 2047.13 Before that deadline, the bill allowed utilities to pay solar customers a new, lower rate – known as the "excess distribution generation" ("EDG") rate – when solar penetration reached 1.5% of their summer peak load, or by July 2022.

CenterPoint (previously known as Vectren), one of Indiana's utilities, was the first to reach this 1.5% benchmark and in 2021 filed a request to institute the EDG rate. CenterPoint also proposed switching from monthly net metering to instantaneous netting, in which customers pay the full retail rate for all power used from the grid, and all solar power sent back to the grid is paid at the much lower EDG rate. The Indiana Utility Regulatory Commission ("IURC") approved CenterPoint's full request in the spring of 2021. Indiana's other predominant utilities, including NIPSCO, AES, Indiana Michigan ("I&M") Power, and Duke Energy, have followed suit in requesting the same instantaneous netting arrangement, and the IURC has approved their requests.

In the 2020 South Carolina Public Service Commission ("South Carolina PSC") proceeding in which Duke Energy Carolinas proposed a successor tariff to its monthly netting program, Duke estimated a cost shift of $35-$40 per month per monthly netting solar customer. The customer participation rate for monthly netting in South Carolina was 1.4% in 2021 when the South Carolina PSC approved a settlement agreement (to which Vote Solar was a signatory) to reform the NEM tariff and to greatly reduce the cost shift.[14]

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[12] *See also* I*n Re: Review of Policies Related to Customer-Owned Solar Generation and Possible Modification of the Commission's Current Net Metering Rules*, Louisiana Public Service Commission, Docket No. R-33929 (Sept. 11, 2019).

[13] *See* Ind. Code §§ 8-1-40-1 et. seq. (2022).

[14] Order Approving Stipulations, Approving Interim Riders and Establishing Solar Choice Tariffs, In Re: Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Establishment of Solar Choice Metering Tariffs Pursuant to S.C. Code Ann. Section 58-40-20, Docket Nos. 2020-264-E and 2020-265-E (May 30, 2021) (transitioning to permanent net metering tariffs using strategic time of use rates, a monthly grid access fee, a $30 minimum monthly bill, and monthly netting with payments at the avoided cost rate); *See also*, N.C. Gen. Stat. § 62-126.4(b) (2022) (requiring the North Carolina Utilities Commission to establish net metering rates under all tariff designs that ensures that the net metering retail customers pays its full fixed cost of service, which may include fixed monthly energy and demand charges).

Arizona has adopted a similar path. Since the aforementioned ACC decision eliminating the state's retail net metering program, the state has implemented net billing, under which utilities purchase excess solar at an "excess generation credit rate" that is worth less than the retail value of electricity. As with Indiana, this program employs instantaneous netting as well. Further, the ACC determined that rooftop solar customers are partial requirements customers who export power to the grid and may be separated into their own rate class for the purposes of assessing additional customer charges for net metering.

Intervenors have offered testimony noting that many states have not eliminated retail net metering, or they have adopted a variety of export compensation structures that retain elements of monthly netting. (Tr. 4350-4351, 4383-4384, 4397-4398.) But this testimony misses the point. Other states may have other programs, but all have acknowledged monthly netting is an inappropriate structure and the least-optimal option. Monthly netting was primarily enacted decades ago as a crude and easily administrable accounting method to compensate distributed solar resources. Notably, monthly netting was not based on any economic foundation as to how these resources should be fairly compensated. This has resulted in many states re-evaluating long standing net metering policies and attempting to quantify the "value" such resources provide. In considering whether to expand monthly netting, the Commission should take the lessons learned in other states and prevent similar problems from occurring here in Georgia.

5. <u>The Cogen Act prohibits a compensation rate for BTM resources in excess of avoided cost</u>.

Notwithstanding the cost shift and customer fairness issues associated with monthly netting described above, Georgia law prohibits the Commission from adopting a compensation rate for RNR customers that exceeds the Company's avoided cost. Unlike other jurisdictions referenced above, Georgia has not legislatively mandated or approved monthly netting. The Georgia Cogeneration and Distributed Generation Act of 2001 ("Cogen Act"), which governs the rates and structure to be adopted under the RNR tariff, plainly states that the Company is not required to purchase BTM generation at a rate that exceeds the Company's avoided cost. Indeed, while the Cogen Act clearly establishes an avoided cost cap to BTM compensation, the Cogen Act does not mandate or require the Company to credit BTM generation at the Company's retail rate for electricity.

The Cogen Act requires that the Company purchase excess energy from customers with BTM generation, like those served under the RNR tariff, until the aggregate demand of customer-owned generation exceeds 0.2 percent of the Company's annual peak demand. The Cogen Act provides that—for instances where a customer's generation exceeds the customer's demand—the Company must pay for excess kilowatt-hours at an "agreed to rate" and may levy certain fixed customer charges to recover costs associated with serving BTM generation. As stated in the Cogen Act:

> (1)(C) When electricity generated by the customer's distributed generation system exceeds the electricity supplied by the electric service provider, the customer generator:
>
> (i) Shall be billed for the appropriate customer charges for that billing period; and
>
> (ii) Shall be credited for the excess kilowatt-hours generated during the billing period *at an agreed to rate as filed with the commission*, with this kilowatt-hour credit appearing on the bill for the billing period; or
>
> O.C.G.A. § 46-3-55(1)(C) (emphasis added.)

First, the Cogen Act's reference to an "agreed to rate approved by the Commission" makes clear the legislature intended for the Commission to establish an RNR-specific rate different from the Company's retail rate. Had the Cogen Act simply intended for the Company to compensate BTM generation at the retail rate, the Cogen Act would not refer to this additional "agreed to rate" for BTM resources. Second, the Cogen Act further states that the "agreed to rate" the Company must pay to BTM generation shall not exceed the avoided cost rate, unless such generation is subscribed under a renewable energy program. Even in this limited exception, however, the Cogen Act only requires the Company to pay a rate equal to the cost of energy:

> (a) An electric service provider will only be required to purchase energy as specified in Code Section 46-3-55 from an eligible customer generator on a first-come, first-served basis until the cumulative generating capacity of all renewable energy sources equals 0.2 percent of the utility's annual peak demand in the previous year; provided, however, that *no electric service provider will be required to purchase such energy at a price above avoided*

> *energy cost unless that amount of energy has been subscribed under any renewable energy program.*
>
> (b) Once the capacity is subscribed, an electric service provider may purchase energy from an eligible customer generator *at a cost of energy* as defined for a utility by the commission, in the case of an electric utility, or by the appropriate governing body, in the case of any other electric service provider or electric supplier.
>
> O.C.G.A. § 46-3-56 (emphasis added.)

The Company's "cost of energy" for BTM solar is equal to the Company's Solar Avoided Energy Cost rate—the rate currently provided to BTM instantaneous netting customers under the RNR tariff.[15] Neither the Cogen Act, nor Georgia public utility law generally, define a "renewable energy program" nor do they lay out the necessary steps for such energy to be "subscribed." A reasonable interpretation is that the phrase "unless that amount of energy has been subscribed under any renewable energy program" means that the Commission can establish a program whereby one or more customers who desire to purchase BTM-generated energy at a higher rate can do so—"subscribe"—with the purpose of increasing compensation to BTM generators. Such a program, properly designed, would further comport with the text of the Cogen Act because it would not shift the costs of the higher compensation rate to non-participating customers. But even with this generous interpretation, the Company still would not be required under the Cogen Act to purchase such energy from BTM sources at a rate that exceeds the cost of energy.

The Cogen Act's deliberate use of the term "energy" makes clear an intent to capture only the energy portion of the customer's electric bill and exclude compensation for transmission and distribution and other services—all of which are components of the Company's retail electric rate.

As the testimony of Company Witnesses Legg and Evans demonstrates, the Company's limited implementation of monthly netting results in significant cost shifts between monthly netting customers and non-participants. Rather than expanding monthly netting, the Cogen Act requires the Company to compensate customer generation at the avoided cost rate (absent Company agreement or a subscription program). To be clear, this is precisely the Company's existing

[15] Per the BTM Joint Recommendation filed at and approved by the Commission in June 2017, the Renewable Cost Benefit Framework is applied to the Solar Avoided Energy Cost value.

instantaneous netting structure under the RNR tariff, first established by the Commission shortly after the legislature first enacted the Cogen Act over twenty years ago, which should remain the structure moving forward.

6. The Commission should adopt the Company's RNR tariff recommendations to address the cost shift and consumer protection concerns.

a. The Commission should implement a default three part rate for RNR customers to mitigate the ongoing cost shift and incorrect price signals.

Due to the disproportionate cost shift presented under the Company's current RNR tariff, the Company proposes requiring all customers who enroll in RNR on or after January 1, 2023 to take service under a three-part rate, such as TOU-RD. Three part rates, connect cost drivers with cost recovery and ensure that RNR customers take service on a rate that is closer to their actual cost of service, thereby lowering the disproportionate cost shift to non-participating customers. Adopting a rate design structure that better reflects the cost to serve RNR customers is the first step on the path toward addressing the cost shift and adopting a BTM solar program protective of non-participating customers.

Notably, monthly netting undermines fundamental principles of cost causation and rate design by artificially elevating the value of excess energy to the level of the Company's total cost of service to generate electricity, deliver electricity across its system, and provide the infrastructure for a safe and reliable system. These are sunk costs, which are recovered over time and reflect substantial investments that provide a real value to customers. The Company cannot simply reduce its distribution and transmission costs that are necessary to serve its customers and they are appropriately recovered in rates as a component of the cost of electric service. If a rate structure requires the Company to over-compensate RNR customers for their excess energy, this subsidy necessarily shifts the responsibility for paying these customers' share of system costs to non-participating customers. In summary, the current RNR tariff's cost shift, which all parties agree exists, , is caused by RNR customers' ability to bypass virtually all volumetric rates. This cost shift is mitigated with a three-part rate that is more reflective of the Company's actual cost to serve RNR customers.

PIA Staff and Intervenors primary concerns with the TOU-RD rate is that the rate lowers compensation for BTM solar. PIA Staff and Intervenors concerns are related to what compensation

levels BTM solar customers receive and not whether the rate is fair, cost-based and non-harmful to non-participating customers. As pointed out during the hearing, Commissioner Shaw identified that without a time varying or demand-based rate structure, a monthly netting customer is under no incentive to consume self-generated power at peak times, or to install energy storage or modify behavior to maximize the alleged benefits of self-generated power. (Tr. 4854.) Under the Company's proposal to adopt the TOU-RD rate for RNR customers, this issue would be addressed, as the TOU-RD rate sends the appropriate price signals to customers. With monthly netting, this price signal is not sent, because excess energy if fully compensated at the retail rate.

b. Continued growth in the solar BTM market requires additional consumer protections.

Another unfortunate externality of expanding BTM solar resources has been an increasing number of unethical business practices employed by some solar marketers, lead generators, solar installers, and solar loan providers offering services to Georgia Power's BTM customers. Increasing the incentives for BTM resources without additional oversight of BTM service providers invites potentially more unqualified actors and additional customer complaints. Therefore, in addition to its recommendations that the Commission reject expansion of the monthly netting pilot, the Company proposes the development of a formal framework for the Commission's referral of consumer complaints to the Consumer Protection Division of the Georgia Attorney General's Office to help protect customers from dishonest and misleading business practices in the marketplace for BTM generation resources.

V. CONCLUSION

For all the above reasons, the Commission should approve Georgia Power Company's 2022 Rate Case as filed by the Company.

Respectfully submitted, this 8th day of December 2022.

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Docket No. 44280

In Re: Georgia Power Company's 2022 Rate Case

PROPOSED ORDER OF GEORGIA POWER COMPANY

Record Submitted: December 8, 2022 Decided: December __, 2022

APPEARANCES

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BY THE COMMISSION:

I. GEORGIA POWER COMPANY'S 2022 RATE CASE

On June 24, 2022, Georgia Power Company (the "Company" or "Georgia Power") filed this rate case pursuant to the terms and conditions of the Georgia Public Service Commission's (the "Commission") February 6, 2020 Order Adopting Settlement Agreement in Georgia Power's 2019 Rate Case in Docket No. 42516 ("2019 Rate Case Final Order"). In the 2019 Rate Case Final

Order, the Commission provided Georgia Power with specific instructions for its next filing as follows:

> The Commission finds that a three-year term for the Settlement Agreement as Modified ending December 31, 2022 is reasonable. By July 1, 2022, the Company shall file testimony and exhibits required in a general rate case along with supporting schedules required by the Commission to support a "traditional" rate case. The test period utilized by the Company in its rate case filing shall be from August 1, 2022 to July 31, 2023. The Company may propose to continue, modify or discontinue this Alternate Rate Plan. The Company shall also file projected revenue requirements for calendar years 2023, 2024, and 2025.

Docket No. 42516, Order Adopting Settlement Agreement.

The Commission has general ratemaking jurisdiction over Georgia Power Company under O.C.G.A. Ch. 2, T. 46. The Georgia Public Service Commission has general supervision over electric light and power companies. O.C.G.A. §§ 46-2-20(a) and 46-2-21. The Commission has "exclusive power to determine what are just and reasonable rates and charges to be made by any person, firm, or corporation subject to its jurisdiction." O.C.G.A. § 26-2-23; see also O.C.G.A. §§ 46-1-1(5), 46-2-24, 46-2-25, 46-2-26.1, and 46-2-26.2.

The Company's 2022 Rate Case filing was made in compliance with the April 7, 2022 Procedural and Scheduling Order, as subsequently amended by the Commission's July 26, 2022 Amended PSO, August 5, 2022 Second Amended PSO, and November 8, 2022 Third Amended PSO (collectively as amended, the "PSO"). The PSO for the Company's 2022 Rate Case identified the procedures to be followed in this docket along with corresponding dates on which designated events were set to occur with respect to the Company's filing. In the body of the PSO, the Commission, pursuant to O.C.G.A. § 46-2-25, suspended the subject matter of Georgia Power's filing for a period of five months ending January 1, 2023. In addition, the Commission determined that the proceedings on the Company's filing constituted complex litigation, as that term is defined in O.C.G.A. § 9-11-33. The Company's 2022 Rate Case filing included information responsive to the Commission's rule regarding Minimum Filing Requirements ("MFRs"); exhibits reflecting Georgia Power's cost of service study, sales and revenue forecast, depreciation rates, and cash working capital; and the testimony and exhibits of Christopher C. Womack, the panel of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, James M. Coyne, Lee Evans, Steven M. Fetter, and Larry T. Legg. On August 22, 2022, Georgia Power filed a supplemental filing to reflect the revenue requirement impacts from various items included in the Final Order approved by the Commission in the Company's 2022 Integrated Resource Plan ("IRP") and demand side management ("DSM") Certification proceedings in Docket Nos. 44160 and 44161 ("Supplemental Filing"). On September 28, 2022, Georgia Power filed an errata to its filing correcting the projected test period revenues for the Fixed Price Alternative ("FPA") rate, and on November 21, 2022, Georgia Power filed an errata to its supplemental direct testimony correcting a formulaic error in its analysis of the cost shift associated with monthly netting (together, the "Errata").

Georgia Power's 2022 Rate Case filing, as amended by the Supplemental Filing and the Errata, requests approval to continue the three-year alternate rate plan ("ARP") structure and requests rate increases of $852, $107 and $453 million to be effective January 1, 2023, 2024 and 2025, respectively. These proposed rate adjustment increases include a levelized adjustment for traditional base rates, a levelized decrease of $1 million for the traditional costs of the ECCR tariff, and annual increases to recover compliance costs associated with coal ash pond closure requirements as well as the DSM costs approved in Docket No. 44161 and municipal franchise fee ("MFF") tariffs. Hearings on Georgia Power's direct case in support of its filing were held September 37, 2022, through September 29, 2022.

In addition to the Commission's Public Interest Advocacy ("PIA") Staff, which has a statutory right to participate in this proceeding, interventions were filed by a number of interested parties. These interested parties included the Americans for Affordable Clean Energy ("AACE"); ChargePoint, Inc.; the Commercial Group; Concerned Ratepayers of Georgia; Cypress Creek Renewables, LLC; EVgo Services, LLC; Georgia Association of Manufacturers ("GAM"); Georgia Coalition of Local Governments (the "Coalition"); Georgia Conservation Voters; Georgia Interfaith Power & Light, Inc. ("GIPL"), the Georgia Solar Energy Association, Inc. ("GA Solar"); Georgia Solar Energy Industries Association ("GSEIA"), Solar Energy Industries Association ("SEIA"), and Vote Solar; Georgia Watch; Interstate Gas Supply, Inc.; The Kroger Company ("Kroger"); Metropolitan Atlanta Rapid Transit Authority ("MARTA"); Resource Supply Management ("RSM"); the Sierra Club; Southern Alliance for Clean Energy ("SACE") and Southface Energy Institute, Inc. ("Southface"); Southern Renewable Energy Association ("SREA"); the U.S. Department of Defense (on behalf of all Other Federal Executive Agencies) ("DOD"); and Utility Management Services.

Thereafter, on October 20, 2022, PIA Staff and Intervenors filed testimony and exhibits presenting their respective direct cases. With the exception of Concerned Ratepayers of Georgia, Cypress Creek Renewables, LLC, Georgia Conservation Voters, GA Solar, Georgia Watch, Interstate Gas Supply, Inc., Kroger, RSM, Sierra Club, and SREA, all other parties to this case filed direct testimony in this proceeding. Also on October 20, 2022, and in accordance with the PSO, Georgia Power filed the supplemental direct testimony and exhibits of Dr. David Gattie and the panel of Lee Evans and Larry Legg. Hearings on PIA Staff and Intervenors' direct cases were held November 8, 2022 through November 10, 2022, and hearings regarding the Company's supplemental direct testimony were held on November 10, 2022.

On November 18, 2022, the Company filed the rebuttal testimony of the panel of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, James M. Coyne, Steven M. Fetter, and the panel of Lee Evans and Larry T. Legg in response to the positions advocated by PIA Staff and various Intervenors. Also on November 18, 2022, PIA Staff filed the supplemental direct testimony and exhibits of the panel of Jamie Barber, Timothy Cook, and Glenn A. Watkins; the Coalition filed the direct testimony David G. Hill, Ph.D.; GIPL filed supplemental direct testimony of Justin Barnes; GA Solar filed the supplemental direct testimony of Kenneth Sercy; GSEIA, SEIA, and Vote Solar filed supplemental direct testimony and exhibits of the panel of Kevin Lucas, Thatcher Young, and Will Giese; and SACE and Southface filed the direct testimony and exhibits of Dr. Marilyn A. Brown and Alden M. Hathaway. On November 23, 2022, Georgia Power filed the supplemental rebuttal testimony of Lee Evans and Larry Legg. Hearings regarding the Company's rebuttal testimony, PIA Staff and Intervenor supplemental direct, and

the Company's supplemental rebuttal testimony were held November 29, 2022 through November 30, 2022.

At each phase of the evidentiary hearings in this case, the Commission also heard from numerous public witnesses who expressed their views on the Company's application, either individually or on behalf of specific groups.

II. FINDINGS OF FACT AND CONCLUSIONS OF LAW

A. ROE, Capital Structure, Cost of Debt, and Financial Integrity

To ensure that the competing interests of all parties were properly considered, the Commission has carefully analyzed all evidence of record including the testimony given and the various exhibits entered by all the parties. As set forth hereinafter, the Commission makes findings of fact and conclusions of law based on the evidentiary record created.

1. Commission Determination Regarding Return on Equity ("ROE").

The difference between the respective ROE recommendations of Georgia Power and PIA Staff were significant. Georgia Power requested an ROE of 11.0%; whereas PIA Staff recommended an ROE of 9.45%, GAM recommended an ROE of no higher than 9.83%, GIPL recommended an ROE of 5.54%, and DOD recommended an ROE of 9.47%.

Georgia Power Witness Coyne relies on the following widely accepted models to develop his ROE determination: the Discounted Cash Flow ("DCF") model, Capital Asset Pricing Model ("CAPM"), Bond Yield Risk Premium model, and the Expected Earnings models for a comparable utility group. Witness Coyne also considers the general economic and capital market environments, and the influence that capital market conditions exert over the results of the DCF, CAPM, and Risk Premium models in arriving at his recommended ROE. Based on that analysis. Witness Coyne estimates the cost of equity to run from 8.99% to 13.55%, with a four-model average of 10.92%. After including an adjustment for flotation costs, Witness Coyne arrives at his recommended allowed ROE of 11.00% in this proceeding.

DOD Witness Reno recommends an ROE of 9.47% with a rate of return of 6.85%, an embedded cost of long-term debt of 3.53%, and an assumed capital structure comprised of 44.18% long-term debt and 53.00% common equity. Ms. Reno bases her ROE recommendation on the higher end of an 8.81-9.47% range derived from her mean estimates of market-based cost of equity methodologies using a proxy group of comparable risk utilities. Witness Reno develops her ROE recommendation using the variants of the Constant-Growth DCF model, the CAPM and Empirical CAPM, and the Comparable Earnings Model ("CEM").

PIA Staff Witness Gorman uses the DCF Model with constant growth, sustainable growth, and multi-stage growth rate estimates, the Risk-Premium Model, and the CAPM to estimate the Company's recommended ROE at 9.45%. Witness Gorman recommends that the Commission reject Witness Coyne's recommended ROE of 11.0% as excessive.

GAM Witness LaConte recommends a ROE of 9.83%. Witness LaConte bases her recommendation on Witness Coyne's analysis, adjusted to remove flotation costs, include the 180-day DCF analysis, and to consider historical market risk premiums in CAPM.

GIPL Witness Ellis recommends a ROE of 5.54%. Witness Ellis uses the DCF and CAPM models, however, he uses drastically different input models that have not been adopted by this Commission and to do so now would be unprecedented.

As in every rate case, the Commission understands its obligation to provide a fair rate of return to the regulated utility. A fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and have an opportunity to earn comparable returns to those of similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts. In determining a fair rate of return in the present case, the Commission is mindful of the standards established by the United States Supreme Court in Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923), and Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942).

Consistent with the Bluefield and Hope decisions, the Commission has considered comparable earnings, financial integrity, and capital attraction in reaching the decision that the 11.0% ROE recommended by Witness Coyne is just and reasonable. An 11.0 % ROE is a fair, forward looking rate of return on equity that provides the Company with an opportunity to earn a return on its investment over the period in which rates are in effect commensurate with returns that investors expect to earn on other investments of similar risk. Accordingly, the Commission finds and concludes that the ROE proposed by Witness Coyne's recommendation will allow the Company to continue accessing capital markets at competitive rates and on reasonable terms.

Witness Coyne's testimony in this case supported his quantification and application of equity flotation costs and a financial risk adjustment. PIA Staff Witness Gorman, DOD Witness Reno, and GAM Witness LaConte presented no credible contrary analysis. Notwithstanding arguments against including flotation costs, Witness Coyne calculates flotation costs based upon economic evidence.

Witness Coyne's use of market capital structure adjusted to correct for financial risk differences between the proxy group's market capital structure and the book regulatory capital structure proposed for Georgia Power is appropriate. Witness Coyne's adjustment is correct and necessary to provide an overall cost of capital commensurate with market expectations. Neither Witness Gorman nor Witness Reno contested his testimony that his financial risk adjustment reflected universally accepted financial economic theory underlying estimations of the of the cost of capital.

The recommendations of Witnesses Reno, Ellis, LaConte, and Gorman are unreasonably low under the governing Hope and Bluefield standards, as was shown by the prospective comparable earnings analysis presented by Witness Reno and Witness Coyne. Although every methodology for estimating the cost of equity has its limitations, no witness presented a sufficient justification for the Commission to depart from its long history of affording due weight to a prospective comparable earnings assessment using the expected performance of a reasonable and representative proxy group

of utilities. The Commission considered the fact that PIA Staff Witness Gorman ignored the comparable earnings analysis, which has been one of the traditional cost of equity analyses employed by prior PIA Staff witnesses and accepted by this Commission. Although Witness Reno conducted a comparable earnings analysis, she provided no justification for ignoring the results.

After careful consideration of the evidence presented by the parties, this Commission concludes that a 9.45% or 9.83% ROE is unjustifiably low and could impede the Company's ability to attract and access capital at reasonable rates and on reasonable terms. The corrected calculation of the cash flows available to the Company after debt service further confirm that a ROE below 9.83% on the existing capital structure is unreasonably low and likely would result in financial harm detrimental to the interests of customers and the public. Through the ROE it awards, the Commission has historically acknowledged the Company's long-standing history of excellent performance and customer service as being above industry average. Witnesses Gorman, Ellis, LaConte, and Reno disregard this Commission's well-established precedent and policy without explanation. In light of the increased risk the Company assumes by agreeing to be bound by an ARP, this Commission has included additional basis points in its awarded ROE. PIA Staff's recommendations would result in at least a 105 basis point reduction in ROE from the Company's current authorized ROE, which ignores and contradicts this Commission's policy of gradualism. Therefore, the Commission approves a 11.0% ROE, as supported by Company Witness Coyne.

2. Commission Determination Regarding Capital Structure.

Georgia Power proposed that a capital structure containing approximately 56% common equity and 44% debt be used for ratemaking purposes in this proceeding. The Company maintains that the proposed 11.0% ROE and 56% equity ratio will ensure that Georgia Power has access to capital whenever necessary, provides the opportunity to earn a fair return for its investors, and does so at rates favorable to customers. Witness Reno accepted the Company's proposed capital structure.

Staff Witness Gorman agrees with the request 56% common equity structure for 2023. Witness Gorman recommends that the Commission lower the Company's equity ratio to 51% common equity for 2024 and 2025 after Vogtle Units 3 and 4 are placed in-service, consistent with the ratio approved in the 2013 Rate Case. According to Witness Gorman, his recommendations are consistent with ratemaking capital structures for other similarly situated regulated utility companies and are adequate to support the Company's bond rating, financial integrity, and credit standing, but at much lower cost to customers. Witness Gorman contends that Witness Coyne's 56% common equity ratio is excessive for a low-risk electric regulated utility and compared to the electric utility industry average.

GAM Witness LaConte testifies that the Company's 56% common equity ratio is excessive and unnecessary to maintain financial integrity. Witness LaConte testified that the average book common equity ratio of Witness Coyne's proxy group, adjusted to remove utilities credit ratings lower than the Company's, is 53% and recommends the Company's common equity ratio be authorized at a level no greater 53% to be more in line with the average of other vertically integrated electric investor-owned utilities.

GIPL Witness Ellis recommends an increase in the Company's proposed common equity ratio to 61.7%, which he justifies due to his drastically low recommended ROE of 5.54%. Witness Ellis does not provide any examples of investor-owned utilities operating under a similar recommended ROE and common-equity ratio structures.

The Commission finds and concludes that adoption of PIA Staff and Intervenors' capital structure positions would contradict this Commission's history of consistent and predictable regulation and harm the Company's financial integrity. The Commission understands that its constructive regulation is a component of the credit rating agencies' assessment of Georgia Power's credit profile because it determines the Company's rate levels necessary to recover expenses such as depreciation, O&M, storm damage cost recovery, and return on investment as well as the terms and conditions of electric service. This Commission reviewed the Company's equity ratio in light of the Tax Cuts and Jobs Act ("TCJA") less than five years ago and determined that an increase in equity capitalization was necessary to counterbalance the negative effects of tax reform on the Company's cash flows. The impacts of the TCJA still exist; therefore, the Company argues it must maintain its 56% equity ratio as carefully reviewed and approved by the Commission in the 2019 Rate Case. None of the capital structure recommendations proposed by PIA Staff or Intervenors adequately reflect Georgia Power's need for continued access to capital on reasonable terms and the importance of maintaining its credit quality. Based on the evidence presented, the Commission finds and concludes that the recommended capital structure of 56% common equity level is just and reasonable to all parties considering all the evidence presented and is necessary to avoid a credit rating downgrade.

3. Commission Determination Regarding Cost of Debt.

Georgia Power recommended a 3.53% cost of debt be used for ratemaking purposes in this proceeding. Only DOD Witness Reno challenges the Company's proposed cost of long-term debt. Witness Reno testifies that market and economic indicators do not support the increasing cost of debt in the ARP. Instead, Witness Reno recommends that for purposes of the ARP, the Commission require that the Company use the cost of long-term debt for the test year (3.53 %).

The Commission finds that the Company's proposed cost of debt is a fair and reasonable approximation of the cost of debt during the three-year ARP period and should be approved.

4. Commission Determination Regarding Georgia Power Financial Integrity.

In addition to setting rates that permit the Company to continue to provide clean, safe, reliable and affordable electric service, the Commission is tasked with ensuring the financial integrity of the Company in order for it to access capital at reasonable rates and on reasonable terms. The Company presented testimony on the impacts of its proposed cost of capital and capital structure as well as the impacts of PIA Staff's proposals on the Company's financial risk metrics used by the credit rating agencies to determine credit quality. Although PIA Staff Witness Gorman calculated the FFO to Debt for S&P, he erred in his calculations and underestimated the effect of his recommendations on the Company's financial health. When corrected, these errors reveal that PIA Staff's proposals would reduce the Company's credit metrics to levels well below the very clearly communicated expectations of the credit rating agencies, and that would likely trigger negative ratings actions (Tr. 3950, 4184.) This degradation in financial health and credit quality would harm the

Company's customers. Notably, PIA Staff counsel did not question the Company's calculations or resulting impact of Witness Gorman's errors during the hearings on the Company's rebuttal testimony.

To evaluate how its recommendations would impact Georgia Power's credit ratings, the Company calculated its FFO to debt ratio, which is a financial metric used to assess risk based on the Company's ability to pay off debt using net operating income alone. (Tr. 799-800.) Mr. Gorman acknowledges the importance of maintaining the Company's FFO to debt (financial risk metrics) above the credit rating agencies' general benchmarks, and attempted to present his analysis with that in mind. (Tr. 3531-33.) However, as the Company pointed out on rebuttal, Mr. Gorman's FFO to debt calculation did not impute debt in accordance with S&P's credit metric methodology. This error stemmed from confusion between the PIA Staff and the Company as to whether Georgia Power had debt-like obligations including pension obligations, lease liabilities, and asset retirement obligations and where such obligations are recorded. By excluding more than $5.5 billion of debt imputations, Mr. Gorman's credit metric expectation is overstated and fails to illustrate the harmful effects of his recommended ROE and equity ratio. Had Mr. Gorman's recalculation included the proper S&P debt imputations, it would have shown that the Company's metrics, assuming Staff's adjustments were accepted by the Commission, are insufficient to maintain sufficient access to capital at reasonable rates. Due to this error and the assumptions serving as the basis for Mr. Gorman's recommendations, the Commission does not adopt PIA Staff's proposed ROE and capital structure. The cumulative adjustments recommended by PIA Staff would limit the FFO to debt metric to approximately 20% for the foreseeable future without the opportunity for improvement.

The Commission's action in this proceeding should not impair or worsen the Company's credit quality or restrict the Company's access to capital at reasonable terms and costs. The Commission agrees with the Company that by setting rates based on a 11.0% ROE, 56% common equity ratio, and 3.53% cost of debt is fair and reasonable and will not threaten the Company with a credit rating downgrade.

B. Alternate Rate Plan and Alternate Rate Plan Earnings Band

Under Georgia law, the Commission may not "order" the Company to enter into an ARP unless Georgia Power agrees to such an ARP. Without an agreement, the Commission must resolve this case under traditional ratemaking standards, which involve a single test year analysis and would eliminate the positive attributes of a three-year predictable plan such as the institution of earnings ranges and earnings sharing mechanisms. O.C.G.A. §§ 46-2-25; 46-2-26.1. However, for several rate case cycles, this Commission has approved, and the Company has agreed to, three-year ARPs in lieu of traditional test year ratemaking. The Company recommends continuing the current ARP structure approved by the Commission in the 2019 Rate Case. This would continue the earnings sharing mechanism for earnings above the band and maintain the Interim Cost Recovery mechanism for earnings projected to fall below the band. The Company proposed to keep the current earnings band of 9.50% to 12.00% with the approved ROE as an approximate midpoint.

PIA Staff proposed an earnings band ranging from 8.45-10.45% with the 9.45% ROE set point centered in the middle of the 200-point band. PIA Staff also proposed modifications to the

Company's ARP to apply all earnings above the band to deferred costs rather than shared between customers and the Company.

Regarding the earnings band, DOD Witness Larry Blank recommends an ROE earnings band of 100 basis points above the ROE if the Commission authorizes an ROE below the Company's requested 11%. In the alternative, Witness Blank reiterates his recommendation from the 2019 Rate Case that the earnings band be narrowed to +/- 50 basis points above and below the target ROE based on the assumption that it would reduce the risk to the Company. GSEIA Witnesses Lucas and Young recommended the Commission reduce the approved band to a 100-point band (+/- 50 basis points), with the ROE at the center, but testify that at minimum it should be set at a 200-point band. Commercial Group Witness Chriss supports the Company's band and recommends that the Commission maintain the basis point spread around the band of the final approved ROE.

The Commission has resolved prior Georgia Power rate case proceedings through three-year accounting orders as opposed to traditional rate case proceedings. Under this arrangement, all stakeholders win as demonstrated by the Company's consistent delivery of exceptional service while keeping rates low in relation to other utilities. Maintaining the earnings band incentivizes the Company to continue to innovate and find efficiencies in operations beyond those the Company was able to identify since the last rate case. Customers have benefitted under this structure and the Commission approves the continuation of these benefits for customers under the Company's proposed ARP. PIA Staff's recommendation is effectively an earnings cap with the top end of the band set artificially low at a level below even the Company's cost of equity.

Witness Blank's recommendation to narrow the ROE earnings band to +/- 50 basis points fails to recognize that narrowing the earnings band necessarily increases risk to customers. Increasing the risk to customers alters the fundamental nature of the ARPs that have been in place for the last 25 years. Georgia Power has proposed an earnings band around the proposed ROE that is consistent with the structure of the earnings band previously approved by the Commission.

Therefore, the Commission finds and concludes that since customers benefit under this ARP structure, the Company's three-year proposed ARP is fair and reasonable in light of all the evidence presented. The Commission finds that it is reasonable to adopt the Company's proposed ARP and approve the current earnings band of 9.50% to 12.00%.

C. Commission Determination on Recovery of CCR ARO Compliance Costs

The Company and PIA Staff both agree there should be a continuation of the CCR ARO cost recovery methodology approved in the 2019 Rate Case. GAM Witness Pollock recommends the Company not be allowed to earn a return on the CCR ARO regulatory asset balance until securitization is authorized.

The Company's CCR ARO compliance costs are required to comply with federal and state environmental regulations and are appropriately included in rate base. Further, this Commission approved the Company's Environmental Compliance Strategy, which included the Company's ash pond closure plans and CCR strategy, as part of the 2022 IRP in Docket No. 44160. No party in this case filed testimony or presented evidence challenging the appropriateness of the Company's

CCR ARO compliance costs sought to be recovered in this case. Witness Pollock's recommendation is not currently possible and would require a change in state law to implement. It would be inappropriate for this Commission to deny the Company recovery of its currently incurred financing costs based solely on the potential for future securitization legislation.

This Commission has carefully considered the evidence and testimony presented on these issues and finds that it is just and reasonable for Georgia Power to continue to recover CCR ARO compliance costs over a three-year period in base rates as proposed by the Company because this provides the best balance between the impact on customer's rates and the total cost. No Commission action on securitization of CCR ARO compliance costs is warranted at this time. GAM Witness Pollock's recommendation is denied.

D. Revenue Requirement Adjustments

1. Commission Determination Regarding Levelized or Step Rate Adjustment.

Within its recommended ARP, the Company proposed to levelized its requested rate increase to balance the benefit to customers from three years of stable and predictable rates with the Company's need to timely recover its projected revenue deficiency. The Company argues that customers are fairly compensated for the projected over-collection in the first two years of the levelization. For the projected advancement of revenues in 2023 and 2024, the Company would defer the amount as a regulatory liability, reducing retail rate base and giving customers credit on the advanced amount based on the Company's full weighted average cost of capital. This proposed deferral reduces the levelized revenue requirement requested by the Company and fully amortizes the advancement by the end of 2025. The Company argues a levelized approach to rate increases shifts economic risks to the Company by insulating customers from the impacts of a possible downturn in the sales forecast or cost increases. The Company states that it is better equipped to manage negative economic factors that impact the cost of running the business, as opposed to asking customers to shoulder the impacts, which would occur with increased rates under step increases. The Company claims a levelized approach results in $43 million less being billed to customers than a step increase approach over the three-year ARP.

In contrast, PIA Staff advocates for a step increase approach, which would increase customer rates by an increasing amount during each of the next three years and better align with the Company's demonstrated revenue deficiencies in 2024 and 2025. Under PIA Staff's approach, current rates would be maintained through 2023 and no rate increase would take place until 2024. This results in lower than projected revenue requirements for years 2023 and 2024.

The Commission finds and concludes that in light of all the facts of the case that levelizing the proposed increases over the three-year ARP is the more appropriate approach for customers. All parties support rate stability and the Commission holds that the fluctuation in projected costs year-to-year under a step approach creates greater uncertainty for customers than under a levelized approach. Therefore, PIA Staff's recommended rate adjustment structure with a step increase across the three-year ARP is denied.

2. Commission Determination Regarding Electric Vehicle Charging Facilities.

Since 2014, the Company has deployed electric vehicle ("EV") charging infrastructure throughout the state to bring greater awareness to the benefits of driving electric vehicles, including both economic savings and environmental impact, as well as enabling the growth of EVs in Georgia. The EV chargers were installed to help the Company respond to the evolving needs and expectations of its customers, including expanded access points for customers to charge electric vehicles. Georgia Power's 2022 Rate Case filing reflects (i) $27 million per year for each year of the ARP for infrastructure upgrades to implement the Make Ready program and (ii) $3 million per year to maintain the development and deployment of the Community Charging program, both of which connect communities across the state through corridor chargers and serves the infrastructure needs of existing drivers in high-adoption regions. The Company proposed to use the Community Charging program to expand critical charging infrastructure to alleviate charging deserts that are found in rural and underserved communities and would not impact existing competitive charging markets.

The Company argued that because the Commission has previously approved the recovery of certain EV-related costs from both the Make Ready and Community Charging programs and because of their proven success, the Commission can and should approve the Company's full EV-related request in this proceeding. Nevertheless, Georgia Power acknowledged that the actual amount to be recovered is a policy decision by the Commission.

PIA Staff Witnesses Trokey and Smith excluded in full both Make Ready and Community Charing program EV costs and revenues from rate base in their recommended adjustments to the Company's 2022 Rate Case filing. According to PIA Staff, Make Ready program costs should not be included in the Company's base rates because the program obligates all customers to subsidize an unregulated service, from which they will not directly benefit. Staff argues that the Company's implementation of Make Ready to date has exceeded the scope of uses specified in the 2019 rate case stipulation. Staff further argues that the Make Ready Program creates an uneven playing field for EV Charging Service providers. Regarding the Community Charging program, Staff argues the program does not generate enough revenue to cover its costs and that it is inappropriate to allow the Company to expand its market share of retail chargers at the expense of customers in light of market competition and increased state and federal fundings.

The AACE Witness panel of Witnesses Akers, Nelson, and Selvidge support the concept of the Make Ready program but recommend that it include targeted goals, objectives, guardrails, and be subject to Commission review. The panel argued that the Company's current community chargers are not serving charging deserts. The AACE panel recommended the Community Charging program be limited to only provide level 2 charging, and proposed that the Company be directed to develop public guidelines through which the need for community charger investment can be identified.

EVgo Witness Murchie recommended the Commission approve the Company's proposed expansion of the Make Ready program. Witness Murchie recommended the Commission direct the Company to develop and publish its program rules and requirements and expand eligibility to include third-party charging station owner-operators. Witness Murchie also recommended the Commission approve the Community Charging program with additional specifications. He

recommended the Company use objective and publicly available siting criteria to determine the location of its Community Charging stations and that it file a pricing proposal with the Commission based on a market analysis to allow stakeholder and additional Commission review.

ChargePoint Witness Wilson testified in support of both the Make Ready and Community Charging programs, and Coalition Witnesses Deffley and Nifong provided testimony in support of the Make Ready program and recommended its eligibility expand to include sites with less than five charging stations.

The Commission finds and concludes that the $30 million annual capital investment for projected capital and O&M costs associated with the Company's two electric transportation programs should be included in the Company's retail rates. As previously stated by this Commission, whether EV charging facility costs warrant inclusion in the Company's cost of service is a matter of Commission policy. This Commission finds that EV charging facility costs must not be examined in isolation: EV charging stations serve as much more than an additional source of revenue for the Company or any other business for that matter. Electric transportation investments also help attract economic growth, as evidenced by the major EV manufacturing announcements, and EV charging stations provide public benefits above and beyond dollars and cents. For example, the overall grid benefits from EV drivers who routinely shift their load and place a positive benefit onto the grid. In addition, evidence presented by the Company indicates that the Make Ready program has positive Rate Impact Measure values, which benefits all customers by putting downward pressure on rates. Accordingly, the Commission finds that allowing EV charging station costs into rate base strikes the right balance for the monetary and non-monetary benefits associated with EV infrastructure deployment.

3. Commission Determination Regarding the Company's Grid Investment Plan

Georgia Power's Grid Investment Plan is a 12-year strategic effort that focuses on (1) improving distribution reliability and (2) replacing aging transmission assets. The Commission approved the first three years of projected capital expenditures for this program in the 2019 Rate Case. As part of its current filing, the Company requests that the Commission approve dollars associated with the next three-year period of the Grid Investment Plan (2022-2025). Company Witness Robinson testified regarding the Company's Grid Investment Plan request in this docket. He explained that while the Grid Investment Plan objectives remain unchanged, the Company refined certain program components and assumptions based on the positive insights, learnings, and data gathered during the initial three-year implementation period of the Grid Investment Plan. The Company has requested $2.2 billion for the transmission and distribution portions of the Grid Investment Plan for projects to be initiated during the three year ARP window from 2022 through 2025.

PIA Staff witnesses Alvarez, Stephens, and Rana oppose the Grid Investment Plan and recommend that the Commission: (1) reject all transmission investments planned for the next three years, and (2) remove 85% of the planned distribution investments. Through these recommendations, Witnesses Alvarez and Stephens ask that the Commission reverse course and disregard the evidentiary record from the 2019 Rate Case and the present docket supporting the Company's investment in the Grid Investment Plan. Regarding the transmission portion of the Grid Investment Plan, PIA Staff contends that the Company is prematurely replacing equipment

based solely on asset age and recommends that Georgia Power be required to employ more objective testing and inspection practices for identifying appropriate transmission investments. Regarding the distribution portion of the Grid Investment Plan, PIA Staff recommends that this Commission eliminate 85% of the planned distribution investments included in the Grid Investment Plan through denial of the undergrounding and Basic Insulation Level investments. In addition, Witnesses Alvarez and Stephens recommend that all Grid Investment Plan costs be accompanied by corresponding reliability improvements outweighing such cost. Given that the Company's revised program components based on learnings from initial implementation, Witnesses Alvarez and Stephens question all estimate and benefit projections underpinning the Grid Investment Plan. PIA Staff suggests that no pending "reliability emergency" that justifies dramatic increases transmission and distribution expenditures as proposed in the Grid Investment Plan.

The Company filed rebuttal testimony responding to the issues raised by Witnesses Alvarez, Stephens, and Rana. The Company fundamentally disagrees with Staff's Grid Investment Plan-related recommendations and overall characterization of the rationale and justification for these investments. The Company rebutted the notion that the Grid Investment Plan involves the "premature replacement" of aging transmission assets. The Company explained in the 2019 Rate Case and in the current docket that asset age drives the transmission portion of the Grid Investment Plan. According to the Company, Georgia Power employed objective approaches to determine which equipment should be replaced as part of the Grid Investment Plan as proposed by PIA Staff. Witness Robinson pointed out that the Company relied on its long history of robust maintenance practices, internal experience, and historical operational knowledge to determine which transmission equipment will be replaced as part of the Grid Investment Plan. The Company incorporated this experience into its recommendation to replace transmission equipment that will be greater than the Company expected life by the end of the Grid Investment Plan period. Georgia Power explained that transmission equipment installed during the 1950s, 1960s, and 1970s, is now approaching 50, 60, and 70 year lives. The transmission portion of the Grid Investment Plan reasonably targets the replacement of aging assets to preserve and improve system reliability and help ensure the safety of the general public and Company employees.

The Company also responded to arguments that the Commission should require cost-benefit analyses for each transmission investment included in the Grid investment Plan. The Company maintains that such analyses are impractical and not useful given the dynamic and networked nature of the transmission system. Witness Robinson identifies several factors that complicate the development a meaningful and accurate cost-benefit analysis of these investments, including failure type (controlled or catastrophic), impacts on other capital projects, lead times for replacement equipment, and redispatch generation-related costs.

Georgia Power also countered PIA Staff's distribution-related recommendations. Witness Robinson explained that eliminating 85% of the planned distribution investments as proposed by Witness Alvarez and Stephens, eliminates the overarching purpose and rationale supporting the Grid Investment Plan. The Company disagreed with PIA Staff regarding the existence of a pending reliability emergency and maintains that Georgia Power's system reliability will continue worsening each year that the Company does not make these grid investments. The Company presented data showing that from 2013—2016, its system average interruption duration index ("SAIDI") worsened by approximately 44% and system average interruption frequency index

("SAIFI") worsened by approximately 10%. The Company highlights that it carefully and strategically developed the distribution portion of the Grid Investment Plan to ensure lasting reliability improvements while minimizing the total cost to the customer. Witness Robinson also rebutted arguments that it reduced reliability expectations by revising the end-state SAIDI for the distribution portion of the Grid Investment Plan. Witness Robinson highlights that Georgia Power appropriately acted in the best interest of customers by reassessing and refreshing the distribution portion of the Grid Investment Plan—these efforts helped ensure that the investments will continue producing positive results in the lowest total cost to customers. The Company explains that is intermittent refinement a multi-year investment plan is essential to ensure that customer capital is managed responsibly. The Company maintains that the Grid Investment Plan encompasses the qualities of the alternative programs recommended by PIA Staff—it accomplishes these goals strategically and appropriately addresses feeder level issues through system level optimization.

Considering all the evidence, the Commission finds and concludes that it is reasonable and appropriate for the Company to continue pursuing investments in the Grid Investment Plan as proposed. Specifically, the Commission approves dollars associated with the next three-year period of the Grid Investment Plan: $2.2B for the 2023-2025 period.[1] The Commission notes that Company witness Robinson presented detailed and persuasive testimony in support of the Grid Investment Plan. In light of the Commission's assessment of the credibility of witnesses opining on the facts and legal considerations at issue with the Grid Investment Plan, the Commission relies heavily on Witness Robinson's testimony.[2] Witnesses Alvarez, Stephens, and Rana did not present sufficient evidence challenging the reasonableness and justification for the Grid Investment Plan-related work. The recommendations and testimony presented by these Staff witnesses ignored the potential risks and cost increases that could result from rejecting the Grid Investment Plan and delaying T&D investments.

Based on the foregoing, the Commission finds and concludes that as in the 2019 Rate Case, Georgia Power has demonstrated the need for the investments outlined in the Grid Investment Plan and the Grid Investment Plan is in the public interest. The Commission finds that the Company's approach represents a reasonable and cost-effective approach to managing grid-related risks during a period of transformation.

4. Commission Determination Regarding DERMS / Section G Proposals

The Company requested $100 million to invest in a Distributed Energy Resource Management System (DERMS) to integrate Distributed Energy Resources (DER) with greater visibility, predictability and control. PIA Staff proposes to reject DERMS spending until the penetration level of DER on the grid increases. PIA Staff claims that existing systems and processes can manage DER. The Company persuasively argued that DERMS will allow the Company to consider demand side resources alongside supply side resources in future IRPs, as ordered by the Commission in the 2022 IRP. Further, the Commission supports the Company's implementation of DERMS at this point will also allow for maturation of the DERMS solution as thousands or tens of thousands of additional DER are connected to the grid in the coming years.

[1]Exhibit ___(APA/SPA/ADH/MBR-7) contains the distribution packages for the 2023-2025 period and Exhibit___(APA/SPA/ADH/MBR-8) contains the transmission packages for the 2023-2025 period.

As such, the Commission finds and concludes that the Company's investment and requested funding for DERMS is reasonable and should be approved in order to optimize the integration of DER on the Georgia Power system.

5. Commission Determination Regarding Stock-Based Compensation and Payroll Taxes.

The Company included expenses related to stock-based compensation in its 2022 Rate Case filing. The Company explained that the total compensation plan, including stock-based at-risk compensation is market competitive and appropriately balances operational with financial focus for both short-term and longer term to drive employee behavior in ways that balance the interests of customers and shareholders alike. According to the Company, moving at-risk pay to base pay would not be in the best interest of customers because it would encourage employees to focus solely on short-term operational performance with no balance or accountability to long-term operational costs and efficiencies. Therefore, the Company believes that stock-based compensation should be included in the Company's revenue requirements and recovered in retail rates.

The Company testified that its budgeted costs to attract, retain and engage employees are expenses that arise in the ordinary course of the Company's business and appropriately should be included in the Company's revenue requirements and recovered in retail rates. The Company maintains that customers benefit from a healthy company, which should be measured over the short- and long-term to ensure that the decisions made by the Company are optimized for both short- and long-term benefits. In addition, the Company proposed to include the payroll tax expenses associated with stock-based incentive compensation, which the Company also contends represent prudently incurred costs.

PIA Staff proposed disallowances for the Company's stock-based compensation program expenses. Specifically, Staff removed the Performance Unit Shares ("PSU") and the Restricted Stock Units ("RSU") expense from retail jurisdictional operating expenses establishing the Company's revenue requirement. PIA Staff also recommended reducing the Company's Performance Pay Program ("PPP") expenses by two-thirds to only allow recovery from customers for operational goals that benefit Georgia Power customers.

According to PIA Staff, the stock-based incentive compensation and two-thirds of the PPP expenses for these programs should not be included in the revenue requirement as these costs are 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 addition, PIA Staff recommended that the Commission exclude the payroll tax expenses associated with the stock-based compensation.

In its rebuttal testimony, Georgia Power argued that these proposed disallowances are inappropriate and should be rejected by the Commission. Company witnesses testified that PIA Staff did not base these recommendations on supporting data or market analysis that the Company's expenses are excessive or that the programs are not competitive with the external market. Georgia Power also argued its position is consistent with the 2019 Rate Case Order.

The Commission finds and concludes that it is reasonable and appropriate for the Company to include stock-based compensation and the associated payroll taxes in its revenue requirement. The Company's long-term at-risk compensation program is comparable to and competitive with the utility industry. The Company's long-term at-risk compensation program is comparable to and competitive with the utility industry. The Company's budgeted costs for stock-based compensation to attract, retain and engage employees are expenses that arise in the ordinary course of the Company's business and appropriately should be included in the Company's revenue requirements and recovered in retail rates.

6. Commission Determination regarding Amortization of Retired Unit Remaining Net Book Values.

The Company has proposed to amortize the regulatory assets for Plant Wansley Units 1-2, Plant Wansley Unit 5A, and Plant Boulevard Unit 1, which were retired by August 31, 2022 in accordance with the Company's 2022 IRP, over their remaining useful lives as approved in Docket No. 42516. These proposed amortization periods are consistent with similar regulatory assets and PIA Staff did not object to the Company's proposal.

In addition, the Company requested to defer depreciation and proposed to amortize the regulatory assets for Plant Bowen Units 1-2 and Plant Scherer Units 1-3 over a nine-year period beginning January 1, 2023. Based on the depreciation study filed in this case, Plant Bowen Units 1-2 are scheduled to be depreciated through 2027 and Plant Scherer Units 1-3 are scheduled to be depreciated through 2028 in accordance with the retirement dates proposed in the 2022 IRP. More specifically, the Company requests to defer the difference each year between the amount of depreciation expense recommended under the rates provided in the Company's new depreciation study and the amount depreciation expense would be assuming a nine-year remaining life into a regulatory asset account beginning January 1, 2023. Once the generating units are ultimately retired, the deferred regulatory asset balance, including any remaining undepreciated balance at the retirement date, would be amortized over the remainder of the nine-year recovery period ending December 31, 2031. The Company's request was unchallenged in this case. The Commission should approve the deferral and amortization of Bowen Units 1-2 and Scherer Units 1-3 as requested by the Company without modification.

The Commission finds and concludes that the Company's proposed amortization of the remaining net book value of units retired in the 2022 IRP, which is consistent with the Company's treatment of other regulatory assets and liabilities is reasonable and appropriate. The Commission also finds and concludes that it is reasonable to approve the depreciation deferral and nine-year amortization for the associated regulatory assets for Bowen Units 1-2 and Scherer Units 1-3 as requested by the Company.

E. Cost Allocation

1. Commission Determination Regarding Cost-of-Service Study Methodology.

The Company filed its 2022 Cost of Service Study ("COSS") consistent with the methodology used in prior Georgia Power rate cases. Georgia Power advocated for the continued use of the 12 Coincident Peak ("12-CP") methodology for allocating costs. Further, the Company

states that its COSS accurately reflects cost causation and can be used to judge the adequacy of rates with respect to the costs to serve and be used for rate design purposes.

Instead of the 12-CP production cost methodology, PIA Staff proposes to use the Base Intermediate Peak and Probability of Dispatch methodologies. PIA Staff argues that the shortcoming of the 12-CP method is that accurate load data is required by class throughout the year and that once a system to record such data is in place, the administration and maintenance of such a system is not cumbersome. PIA Staff Witness Watkins stated at hearing that the Company had an abundance of more than adequate data. Thus, the only shortcoming of the 12-CP method identified by PIA Staff does not hold true for Georgia Power.

GSEIA, SEIA, and Vote Solar and GAM propose the Company use either a 4-CP or 6-CP production cost allocation methodology arguing that as a summer peaking utility, the four summer months June through September drive the Company's peak demand and should be the basis for allocating the Company's production costs. However, in rebuttal the Company identified that its system is driven and influenced by non- summer periods in addition to summer peaks, and it utilizes Expected Unserved Energy in its determination of the optimal reserve margin for both summer and winter seasons. The Company argues that this renders a pure summer peak or 4-CP allocator is an oversimplification of the Company's generation planning process.

Based on the evidence presented, the Commission finds and concludes that the Company's cost of service study is reflective of cost causation and is objective, fair, and equitable to the different groups of Georgia Power customers. The Company's cost of service study methodology provides a reasonable basis to functionalize, classify and allocate costs to customer classes, is reflective of the Company's system needs, and is consistent with the methodology employed and approved it its previous rate cases before the Commission. The Commission approves the Company's COSS as filed by Company Witness Evans.

2. Commission Determination on Basic Service Charge.

Georgia Power proposes to increase the Basic Service Charge ("BSC") for the Domestic Group by approximately $2.27 per month. The Company explained that it is proposing to increase all traditional base rates on an equal percentage basis, including rate elements, which therefore includes the basic service charge.

PIA Staff Witness Watkins disagrees with the Company's recommendation to increase the basic service charge on an equal percentage basis. Witness Watkins testifies that the basic service charge should only reflect those direct costs required to connect and maintain a customer's account. Therefore, PIA Staff recommends this Commission deny the Company's requested increase in the basic service charge. PIA Staff recommends in the event that this Commission grants the Company's requested increase, that the income qualified senior discount be increased by an amount equal to the increase in the basic service charge.

GIPL Witness Barnes also recommends the Commission deny the Company's requested basic service charge increase and leave the current residential basic service charge in place. Witness Barnes testifies that that the cost-of-service study erroneously classifies a portion of the

costs associated with the shared distribution system as customer-related based on its Minimum Distribution System ("MDS") analysis.

In rebuttal, the Company proposed to increase the income qualified senior discount by the amount the basic service charge is ultimately increased.

After considering the parties' testimony and all of the evidence presented, the Commission finds and concludes that the Company's proposed BSC increase is just and reasonable and strikes an appropriate balance to provide rates that more clearly reflect actual cost causation, minimize subsidization, and provide proper price signals to customers in the rate class, while also moderating the impact of such increase on low-usage customers. As in prior rate cases, the parties in the present case filed testimony advocating various methodologies for cost allocation and various rate designs favorable to each party's interests. In light of the reasonable allocation of costs and rate design contemplated, the Commission finds that the allocation of costs and rate design contemplated and specified by Georgia Power are reasonable and in the best interests of all customer groups.

F. Rate Design

Company Witness Larry Legg provided testimony regarding the Company's existing tariffs and its proposed changes to rate design. The Company testified that its portfolio of rates proposed in the 2022 Rate Case filing offer optionality for customers while supporting a gradual move toward more modern rates. PIA Staff and several Intervenors provided testimony on various rate design issues in this proceeding, as discussed below. Having considered the testimony and exhibits of each witness and the entire record in this proceeding, the Commission makes its findings and conclusions on each of the issues set forth below.

1. Residential Rate Design.

The Company proposes several modifications to its residential rate design offerings. Consistent with its request in the 2019 base rate case, the Company proposes to close the Residential Service (R) tariff ("the R Rate") to new residential customers on January 1, 2023. The default residential rate for new premises would continue to be Time of Use – Residential Demand ("TOU-RD"), and the Company proposes closing Time of Use – Residential Energy Only ("TOU-REO") to new residential customers.

a. Modifications to the R Rate.

PIA Staff proposed several modifications to the 'R' Rate. Staff contends that the Company's retention of a declining winter block rate on the 'R' rate incents wintertime usage in conflict with the Company's winter seasonal planning posture and winter system cost structure. PIA Staff recommend the elimination of the declining-block rates during the non-summer months to a flat rate for all kWh usage due to increasingly higher winter peaks.

The Company responds in rebuttal that the R Rate is antiquated and sends poor price signals to customers regarding their energy usage. The Company argues that it makes little sense to fundamentally alter the R Rate's design in light of its other more modern offerings. The Company recommends closing the R Rate to new residential premises.

b. Closing the Residential Service (R) Rate to New Premises.

Georgia Power requests to begin transitioning from the more antiquated, volumetric option of the R Rate to move toward more modern rates by first closing the R Rate to new residential premises. The Company argues this will allow it to establish new residential accounts that better align with the cost to serve customers. If approved, customers establishing service at new premises will continue to be enrolled in the TOU-RD rate as a default rate, as established in the 2019 Rate Case Order. Customers will still have the ability to select from four of the most modern rate options. After the initial year of service at those new premises, customers will be eligible for two additional rates. The R Rate would remain available to existing residential premises on the Georgia Power system that established service prior to January 2023.

PIA Staff opposed the Company's recommendation to close the R Rate to new premises. PIA Staff argued that while it supports marketing and education to grow customer adoption of modern rates, Staff does not support the Company eliminating customer choice in rates. GIPL Witness Barnes also opposed the Company's proposal to close the R Rate. Based on concerns with time of use rates in general and specifically the default TOU-RD, both PIA Staff and Witness Barnes recommend the Company re-designate the R Rate as the default residential rate.

c. Time of Use – Residential Demand ("TOU-RD")

To transition to more modern rate designs and to provide customers with price signals that more accurately reflect the cost of service, the Company proposes maintaining TOU-RD as the default rate for new residential premises. The Company argues that this a logical step in modernizing its rate design offerings.

PIA Staff and Certain Intervenors object to the Company's TOU-RD proposal. PIA Staff assert that the TOU-RD rate would be a poor default rate for residential customers because customers lack sufficient information or knowledge on these issues to appropriately minimize their bills on such a rate. PIA Staff, the Coalition, and GIPL Witness Barnes further argued that from analysis of Company data, TOU-RD has been significantly more expensive than the R Rate or TOU-REO.

The Company testified in rebuttal that TOU-RD is designed to be revenue neutral for the average residential customer and to provide customers with better price signals to enable them to make more informed decisions to reduce their energy use and electric bills. The Company stated that the bill comparisons that PIA Staff highlight in testimony are heavily skewed by extremely low usage and fail to tell a complete story because they represent premises that are new to the Company's system. The Company testifies that the average monthly usage for those premises is far below the level at which the usage will ultimately mature.

The Company testifies that customer surveys reflect TOU-RD customers are more satisfied with their rate and feel more knowledgeable regarding the behaviors that can help them capitalize on their rate plan and reduce their energy bills.

d. Time of Use – Residential Energy Only (TOU-REO)

The Company requests closing TOU-REO to new customers to avoid confusion associated with multiple residential TOU rates. PIA Staff and certain Intervenors recommend that TOU-REO continue to be offered to all residential customers because this rate provides a viable option for customers to shift their load and usage patterns from on-peak hours to off-peak hours. PIA Staff recommends if the Commission close the R Rate to new premises, TOU-REO is a more appropriate default time of use rate for customers than TOU-RD.

The Company testified in rebuttal that TOU-REO is much more volatile than TOU-RD and, moreover, that TOU-RD sends better price signals and more appropriately reflects the cost of a customer's electric service. The Company reiterated that TOU-RD provides the most appropriate pricing signals to customers to enable to them modify their usage patterns and reduce their electric bills.

e. FlatBill

Staff approves of the Company's request to have a $50 minimum bill for FlatBill customers. Staff recommends the Company to expand customer awareness of its budget billing offerings.

Commission Decision on Residential Rate Design Issues.

In light of the parties' testimony and all of the evidence presented, the Commission approves Georgia Power's request to close the 'R' Rate to new residential premises and supports the Company's gradual movement toward more modern rates. Closing the R rate to new premises does not affect existing customers on the 'R' rate unless they move to a residence that has never received service from Georgia Power before. In beginning the move toward more modern rates, the Commission finds PIA Staff and Intervenor arguments to otherwise modify the 'R' Rate by adjusting the declining winter block rate and usage tiers to be unnecessary.

The Commission also approves the closure of TOU-REO and the continuation of TOU-RD as the default residential rate for new premises. PIA Staff and Intervenors have not provided sufficient justification for the need for the Company to offer residential customers more than two time-of-use rates where TOU-RD provides the most modern and appropriate pricing signals.

The Commission approves the Company's proposed adjustments to FlatBill, TOU-RD, and each of the remaining residential tariffs as filed by the Company.

2. Commission Determination Regarding Commercial and Industrial Rate Design.

a. Charge-It Electric Vehicle ("CIEV") Rider

The Company requests the Commission approve its new CIEV rider. The CIEV rider will modify the monthly billing demands by using Billing Demand Adjustment Factors. The Company

proposes CIEV as a temporary rider to expire either at the end of 48 months or when the rolling 12-month load factor for the account reaches 15% or greater.

PIA Staff recommend the Commission approve the CIEV rider as filed in the Company's Errata-Supplemental filing with quarterly reporting regarding the location, peak demand, usage, and revenue received from CIEV customers. EVgo Witness Murchie and ChargePoint Witness Wilson also supports the CIEV rider. Witness Wilson and Murchie recommend the Company allow any qualifying customers, not just new customers, take service under CIEV. AACE Witnesses Akers, Nelson, and Selvidge argue that the CIEV rider discriminates between EV charging providers.

The Company explains in its rebuttal that the CIEV rider is a time limited offering to encourage the growth of electric vehicles ("EVs") in Georgia and therefore argues it is inappropriate to expand participation to existing customers, which would eliminate the incentive for adoption of EV charging by new premises.

b. Embedding ECCR costs in Marginal Rates.

PIA Staff recommends that customers on marginal rates be assessed the fully embedded cost of the ECCR tariff. PIA Staff and GIPL Witness Barnes argue that ECCR costs should be recovered based on a customer's kWH energy usage basis.

The Company disagrees, arguing that by including fully embedded costs like ECCR in marginal rates is inappropriate because such a change is contrary with how marginal rates like RTP are designed to operate. The Company explains that fully embedded costs are recovered from the Customer Baseline Load ("CBL") portion of the marginally priced rates, while marginal costs are recovered from the marginal portion of the rates. The Company also states that the ECCR costs include CCR ARO compliance costs, which are fully embedded costs incurred by the Company independent of a customer's kWh usage. As such, counter to recommendations by GIPL Witness Barnes and PIA Staff, ECCR costs are appropriately recovered through the CBL portion of the rate. The Company asserts that if ECCR costs, or other fully embedded costs, were allocated to the marginal portion of RTP rates, RTP costs would increase by approximately $150 million overall.

Given that the RTP rate is a critical rate for large, economic development customers that are considering locating, relocating, or expanding operations in Georgia and that a cost shift of this magnitude would significantly decrease the appeal of the rate to current and future customers, the Commission rejects PIA Staff and GIPL's proposed ECCR modifications to marginal rates.

c. Proposed Modifications to Customer Baseline Load ("CBL") Reduction Criteria.

DOD Witness Blank recommends modifying the Company's criteria for the reduction of CBLs for customers who install behind the meter generation. The Company disagreed with this proposal because customer generation does not permanently remove the customer's load and does not justify the reduction of a customer's CBL. According to the Company, CBLs may be reduced

when load originally represented in the CBL has been permanently removed. Mr. Blank did not provide sufficient persuasive evidence to merit a change in the CBL criteria. Therefore, the Commission denies Witness Blank's recommendation.

DOD Witness Blank also criticizes the Company's requirement that a CBL reduction assessment based on historical load is not permitted unless the customer stops taking service under the RTP tariff for two years. In contrast, the Company supports the requirement that a customer remain off the RTP rate for two years before returning or requesting a CBL reduction, because short term changes to a customer's usage should not result in the permanent conversion of embedded load into marginal load on the RTP rate. The RTP tariffs include provisions to revise the CBL as a result of actions like permanent equipment removal and energy efficiency improvements, but the tariffs specifically prohibit CBL revisions due to temporary factors such as economic downturns. As previously held by this Commission, requiring customers who have not removed load to stay off RTP for 24 months in order to set a new CBL preserves the integrity of the RTP program and protects other customers from potential cost shifts that might result from premature revision of the CBL. The Commission denies Witness Blank's recommendation.

d. Fixed Price Alternative and Price Protection Product offerings

PIA Staff proposed to modify the terms and conditions of the Fixed Price Alternative ("FPA") and Price Protection Product ("PPP") offerings to remove Company discretion over when to offer these rates. The Company maintains that removing its discretion regarding when to offer these products adds unnecessary risk that could be borne by other customers, since delays in acting during volatile markets could result in the development of product offerings that do not properly reflect pricing impacts. The Company explained that it considers multiple factors when deciding whether to offer the FPA rate and PPP offerings to customers. These factors include, but are not limited to, uncertainty around environmental regulation, fuel markets, and other potential factors that could impact the pricing of these offerings. The Company stresses that it is to maintain flexibility to act quickly and update PPP offerings to best reflect market conditions, especially during times of fuel market volatility as have been experienced for the last year.

Commission Decision on Commercial and Industrial Rate Design Issues.

The Commission finds and concludes that the CIEV tariff is reasonable and appropriately designed to encourage new EV charging service adoption. As such, the CIEV tariff is approved without modification. The Commission further finds and concludes that PIA Staff and Intervenor proposed changes to the Company's commercial and industrial tariffs are not justified and should be denied. This Commission supports the balance the Company maintains in meeting customer demands for more beneficial rates with greater marginal load components. Further, the Commission rejects PIA Staff and UMS' request to expand the TOU-FD eligibility. The Company's commercial and industrial rates as filed should be approved without modification.

3. Community Solar Program

Georgia Power's Community Solar tariff offers qualifying customers the opportunity to support renewable energy and the development of solar power in Georgia by subscribing to a portion of the output from local solar facilities. (Tr. 888, 2184.) Every month, participating

customers pay a fee for a subscription block of the energy produced by Community Solar facilities, and in return receive energy credits on their monthly bill that are based on the production from those facilities. (Id.) Additionally, the equivalent renewable energy credits ("RECs") are retired on the customer's behalf. (Tr. 888, 2184-85.)

In this case, the Company proposes to update the pricing for the existing residential Community Solar Charge from $24.99 to $27.99 per one kilowatt block and proposed that the pricing for General Service ("GS") Community Solar participants be set at $29.99 per one kilowatt block. (Tr. 888, 929.) Georgia Power states that the Community Solar subscription price is designed to ensure that participating customers do not shift costs to other customers when kilowatt hours reduce the monthly bills of participating customers. (Tr. 939.) The Company argues that based on the approved structure of the Community Solar program, a reduction in the price per kW block of energy as proposed by several parties would leave costs unrecovered and, therefore, shift cost recovery to non-participants. (Tr. 914.) The Company states that the Community Solar tariff is not intended to create bill savings for participating customers, but rather, is targeted toward customers who are interested in supporting solar but either do not want or are unable to install solar panels at their premises. The

PIA Staff proposed two alternatives regarding the appropriate pricing for the Community Solar Program offers two alternatives and is premised on a Commission policy determination as to the purpose of the program. PIA Staff's recommendation depends on whether the Community Solar Program is found by the Commission to offer bill savings opportunities for participating customers. As proposed by PIA Staff, if the purpose of the program is to support clean energy and realize bill savings, Staff recommends a pricing reduction to $20 and $22 pricing for residential and commercial customers. If the purpose of the program is to support clean energy but not the opportunity for bill savings, Staff supports the Company's proposed $27.99 and 29.99 pricing for residential and commercial customers, respectively. (Tr.2449-50.)

The Coalition recommended the Commission reject the Company's proposed increase to the subscription price for the Community Solar Program. To increase participation in the program and provide a viable option for those who cannot host or afford rooftop solar, the Coalition recommends two alternatives. First, the Commission could maintain the current community solar fixed price per kW block structure but reduce the price to $16 per kW block for residential customers to exclude lost revenues from fuel, environmental, and nuclear cost recovery riders. Second, the Commission could permit customers to lock in the current $24.99 per kW block rate for the duration of the customer's participation in the program.

Although PIA Staff may believe the purpose of the Community Solar program is an open policy decision for the Commission, the Commission has already determined that the purpose of the program is not for bill savings. In the Commission's June 7, 2017 Order approving the Community Solar Program tariff, the Commission clearly stated that the Community Solar Program "is not designed to produce credits in excess of a customer's usage and a customer should anticipate the [Community Solar] program charges will exceed the value of any bill credits received." *Order approving Community Solar Program and CS-1 Tariff*, Georgia Public Service Commission, Docket Nos. 40161 and 16573 (June 7, 2017) at 2. Rather, as confirmed by the Company, the Community Solar Program is targeted toward customers who are interested in

supporting solar but either do not want or are unable to install solar panels at their premises. While the Company agrees that increased participation in the Community Solar program should be encouraged, increased participation should not be at the expense of non-participating customers. The inclusion of commercial customers in the program and the adoption of the income qualified community solar pilot should help increase customer participation. With regard to the pricing for the Community Solar program, the Commission approves the Company's requested block price increase for the Community Solar program to $27.99 per kW block for residential customers and $29.99 per residential block for commercial customers on the general service rate.

G. Commission Action on the Monthly Netting Pilot.

The Commission-approved a Monthly Netting Pilot ("Pilot") in its 2019 Rate Case. The Pilot directed the Company to offer monthly netting on a pilot basis for the first 5,000 subscribers or until newly installed capacity reached 32 MW. The Pilot provided enrolled customers with full retail credit for excess generation, netted monthly. The Pilot was designed to provide the Company with data to evaluate the effect of monthly netting on the Company's cost of service and customer class cost shifting.

The Company recommends this Commission: (1) discontinue the subsidization of monthly netting customers at the expense of other customers by using the monthly netting methodology combined with volumetric rate structures; (2) require all customers who enroll in the RNR tariff on or after January 1, 2023, to take service under a three-part rate; (3) develop a formal framework for the Commission's referral of consumer complaints to the Consumer Protection Division of the Georgia Attorney General's Office to help protect customers from dishonest and misleading business practices.

1. Expansion of Monthly Netting Pilot.

The Company does not support expanding the monthly netting pilot. The Company asserts that a customer participating in the monthly netting pilot shifts an additional $287 of costs onto non-participating customers on an annual basis. (Tr. 5031.) The Company asserts this represents a cumulative shift of approximately $1.4 million annually for the 5,000 pilot customers. The Company requests recovery of this $1.4 million in this case. The Company also testifies that if left unaddressed and as participation in monthly netting increases, this cost-shift will increase. Therefore, the Company also seeks this Commission's approval to close the monthly netting pilot.

PIA Staff Witnesses Barber, Cook and Watkins do not make a specific recommendation regarding the expansion of the monthly netting pilot but offer the Commission several alternatives, which includes a range of possible compensation rates the Company could use to compensate RNR customers for excess energy pushed back to the grid. This range varies from approximately 6.99 cents to over 13 cents per kWh.

Intervenors supported a continuation of the monthly netting pilot with various caveats. Coalition Witness Hill recommends the Commission continue the Pilot through the next ARP period and recommends a cap of no less 75,000 customers, if one is required. GIPL Witness Barnes recommends the Commission reinstate monthly netting with a cap set at 3% of the Company's 2021 peak demand, to be reassessed once reached, and to include a minimum monthly bill of

$22.43. Witness Barnes also recommends the Commission deny the Company's requested 1.4 million monthly netting revenue erosion adjustment.

GA Solar Witness Sercy recommends the Commission lift both the customer and capacity limits on monthly netting. GSEIA, SEIA, and Vote Solar Witnesses Lucas, Young and Giese recommend the Commission expand the Pilot with no participation cap until the Company adopts a more rigorous cost-based approach to identify and address the cost shift. Witnesses Lucas, Young and Giese propose the Commission implement a $20 minimum monthly bill that is inclusive of the customer charge.

SACE/Southface Witness Brown recommends the Commission reinstate the monthly netting pilot, without a participation cap, for three additional years. Witness Brown recommends the Company conduct an additional cost-of-service study to account for additional benefits of distributed solar that the cost shift did not take into consideration.

On rebuttal, the Company responded that compensating BTM solar resources at the high levels proposed by PIA Staff and Intervenors, which are well above avoided cost and close to the retail rate, will further increase the cost shift to non-participating customers under the RNR tariff, as these values are not credibly tied to any quantification of actual benefit provided by the BTM resource. The Company argues that all parties ignored the Commission's existing and established RCB Framework, which was jointly developed, applied, and approved to compensate BTM generators for excess energy. The Company defends its cost-shifting analysis and argues that neither PIA Staff nor Intervenors were able to credibly rebut it.

2. Three Part Rates.

The Company requests that the monthly netting pilot remain capped at its currently approved 5,000 customers to prevent additional cost shifting and revenue erosion. The Company recommends all new and existing customers participating under the RNR tariff be required to enroll in a three-part rate like TOU-RD beginning January 1, 2023 to better account for and address the cost shift caused by RNR customers, especially those participating in the monthly netting pilot.

PIA Staff disagrees with the Company's recommendation to transition monthly netting customers to TOU-RD, arguing that it is "not well-suited for RNR customers due to high demand charge and extremely low off peak energy price." Coalition Witness Hill, GIPL Witness Barnes, Georgia Solar Witness Sercy, GSEIA, SEIA, and Vote Solar Witnesses Lucas, Young and Giese, and Southface Witness Brown all also oppose the Company's proposal to require new customers enroll in a three-part rate. Witness Sercy recommends customers be allowed to select their rate schedule, and Witness Barnes testifies that TOU-RD is misaligned with cost-causation and is punitive to customers with infrequent high demand.

The Company reiterates in rebuttal that it proposes transition netting customers to three-part rates to reduce the cost shift and testifies that continuing to allow RNR customers to take service under the R rate will only intensify the cost shift. The Company argues that Intervenors fail to demonstrate that the TOU-RD tariff does not appropriately recover costs and instead that Intervenors contentions are reactive to the to the potential for the TOU-RD rate to mitigate the current subsidy available to monthly netting customers on the R rate.

3. Increased Consumer Protection.

All parties support the Company's recommendation to develop a more formal framework for the Commission's referral of consumer complaints to the Consumer Protection Division of the Georgia Attorney General's Office to help protect customers from dishonest and misleading business practices.

Commission Decision on Monthly Netting.

The Commission finds and concludes that the monthly netting pilot resulted in a cost shift to non-participating customers and should not be expanded. In order to address the cost shift associated with BTM generation, the Commission directs that new customers that enroll in the RNR tariff must take part in one of the Company's three-part rates beginning January 1, 2023. RNR instantaneous shall continue to be made available to interested customers. RNR instantaneous customers shall continue to be paid for excess energy pushed back onto the grid at the Company's Solar Avoided Energy Cost rate, consistent with the RCB Framework, and as filed annually with this Commission in Docket No. 16573.

Within 90 days of this Order, the Company and Commission Staff shall initiate discussions and work with the Consumer Protection Division of the Georgia Attorney General's Office to formalize a consumer complaint process to better address consumer complaints related to bad actors in the rooftop solar industry.

III. ORDERING PARAGRAPHS

WHEREFORE, IT IS ORDERED, that the Company's Alternate Rate Plan shall be adopted as proposed and as amended by the Company's Supplemental Filing and Errata and the rates pursuant to the Alternate Rate Plan are just and reasonable, and effective for service rendered from and after January 1, 2023.

ORDERED FURTHER, that the Company is awarded a 11.0% ROE and 3.53% cost of debt, using 56% common equity in the capital structure.

ORDERED FURTHER, that the earnings band shall be 9.50-12.00%, with earnings above the top of the band shared 80/20 with customers.

ORDERED FURTHER, that the Company will recover CCR ARO compliance costs ratably over a three-year period in base rates as proposed by the Company.

ORDERED FURTHER, that the Company may include in base rates the projected capital and O&M costs for the Make Ready and Community Charging programs and the associated electric transportation activities such as the net investment of all the existing community electric vehicle charging facilities, whether located on and off Company property and the associated revenues and expenses, the commercial and residential rebates for installing EV chargers, and an amount for EV education and awareness.

ORDERED FURTHER, that the Company appropriately included stock-based compensation expenses in its revenue requirement in the 2022 Rate Case filing. Georgia Power's long-term at-risk compensation program is comparable to and competitive with the utility industry. Furthermore, the Company's budgeted costs for stock-based compensation to attract, retain and engage employees are expenses that arise in the ordinary course of the Company's business and appropriately should be included in the Company's revenue requirements and recovered in retail rates.

ORDERED FURTHER, that the Company's Grid Investment Plan and projected spend for 2022 through 2025 is approved as filed, without modification.

ORDERED FURTHER, that the Company's DERMS request is approved.

ORDERED FURTHER, that the Company's request to recover $48.9 million over a five-year amortization period ending December 31, 2027, for software and cloud computing costs is just and reasonable and is approved.

ORDERED FURTHER, that the Company's request to implement a new Customer Information System is approved as filed.

ORDERED FURTHER, that the Company's inclusion of $94 million for incremental inflation in the Company's revenue requirement is approved as filed.

ORDERED FURTHER, that the Company shall amortize the regulatory assets for Plant Wansley Units 1-2, Plant Wansley Unit 5A, and Plant Boulevard Unit 1 over their remaining useful lives as approved in Docket No. 42516.

ORDERED FURTHER, that beginning January 1, 2023, for Plant Bowen Units 1-2 and Plant Scherer Units 1-3, the Company shall defer the difference each year between the amount of depreciation expense recommended under the rates provided in the Company's new depreciation study and the amount depreciation expense would be assuming a nine-year remaining life into a regulatory asset account beginning January 1, 2023. Once the generating units are retired, the deferred regulatory asset balance, including any remaining undepreciated balance at the retirement date, would be amortized over the remainder of the nine-year recovery period ending December 31, 2031.

ORDERED FURTHER, that the Company's adjustment to the depreciation rates for Wansley 1-2, Bowen 1-2, and Scherer 1-3, is approved.

ORDERED FURTHER, that the depreciable life for Plant Hatch is extended from 60 years to 80 years.

ORDERED FURTHER, that the Company's request for a three-year amortization period ending December 31, 2025, to recover COVID-19 pandemic response costs is just and reasonable and is approved.

ORDERED FURTHER, that the Company's request to recover a regulatory asset balance of $786,000 as of December 31, 2022, over a three-year amortization period ending December 31, 2025, for costs associated with providing customers hourly usage data is just and reasonable and is approved.

ORDERED FURTHER, that the Company is authorized to opt out of the IRS tax normalization for the purposes of recognizing eligible Investment Tax Credits for battery storage facilities in accordance with the Inflation Reduction Act.

ORDERED FURTHER, the Company's COSS as filed in the testimony of Lee Evans is approved.

ORDERED FURTHER, that the Company's plan to modernize rates by making new residential premises ineligible for the 'R' Rate is approved.

ORDERED FURTHER, that the Company's proposal to streamline the Company's tariff portfolio and avoid customer confusion by closing TOU-REO to new residential customers is approved.

ORDERED FURTHER, that the Company's proposal to increase the minimum monthly offer for new FlatBill customers on both the FLAT and FLAT-GS tariffs from $25 to $50 is just and reasonable and is approved.

ORDERED FURTHER, that the Company's proposal to implement several changes to the RLG tariff to (1) clarify the existing fixture options, (2) expand and clarify the available pole options, and (3) close one fixture to future customer enrollments is approved.

ORDERED FURTHER, that the Company's proposed changes CS tariff to update the pricing for the existing Community Solar Charge from $24.99 to $27.99 per kW block for residential customers and set the price for customers on the General Service ("GS") tariff to be $29.99 per kW block is approved.

ORDERED FURTHER, that the Company's proposed updates to the Simple Solar ("SS") tariff from the 2022 IRP are approved.

ORDERED FURTHER, that the Company's CIEV rider is approved as a temporary rider to expire either at the end of 48 months or when the rolling 12-month load factor for the account reaches 15% or greater.

ORDERED FURTHER, that the Company's proposal to include a new pricing option within the Time of Use – Supplier Choice ("TOU-SC") tariff is approved.

ORDERED FURTHER, that the Commission specifically approves the Company's proposed changes to the TOU-RD, REO, DPEC Rider, RTP, RNR, RLG, CS, and SS tariffs.

ORDERED FURTHER, that the Company's proposed one-time interconnection fee of $200 for customers seeking to interconnect a customer generating facility to the Company's system is just and reasonable and is approved.

ORDERED FURTHER, that the Commission approves the Company's request to eliminate the PLH and SP tariffs.

ORDERED FURTHER, that the Company's proposal to increase the basic service charge to each traditional base rate, except as noted in testimony, on an equal percentage basis is approved.

ORDERED FURTHER, that the Company shall update the senior citizen low income discount to match the increase in the basic service charge.

ORDERED FURTHER, that the Commission approves the modification of the Company's payment and services policies in section F of the Company's Rules and Regulations.

ORDERED FURTHER, that the Company's proposal to include new language in the customer generation section of the Company's Rules and Regulations to clarify when a customer-owned generator is required to undergo witness testing and would be responsible for the appropriate fees associated with this testing is approved.

ORDERED FURTHER, that the Company's proposal to increase the charge for underground residential distribution service found in section C10 of the Rules and Regulations is approved.

ORDERED FURTHER, that the Company's proposed changes to Sections F and G of the Rules and Regulations is approved.

ORDERED FURTHER, the monthly netting pilot resulted in a cost shift to non-participating customers and should not be expanded.

ORDERED FURTHER, that new customers that enroll in the RNR tariff beginning January 1, 2023 must take service in one of the Company's three-part rates.

ORDERED FURTHER, that RNR instantaneous customers shall continue to be paid for excess energy pushed back onto the grid at the Company's Solar Avoided Energy Cost rate, consistent with the RCB Framework, and as filed annually with this Commission in Docket No. 16573.

ORDERED FURTHER, within 90 days of this Order, the Company and Commission Staff shall initiate discussions and work with the Consumer Protection Division of the Georgia Attorney General's Office to formalize a consumer complaint process to better address consumer complaints related to bad actors in the rooftop solar industry.

ORDERED FURTHER, that all changes to tariffs, riders, rules and regulations filed by the Company should be approved as filed unless ordered otherwise in this Order.

ORDERED FURTHER, that Georgia Power shall file compliance tariffs within 60 days of the issuance of this Order, reflecting rates to implement the rate increases ordered herein. These tariffs shall reflect the rate allocations adopted in this Order, and shall be subject to the Commission's review for final approval.

ORDERED FURTHER, that all findings, conclusions and decisions contained within the preceding sections of this Order are adopted as findings of fact, conclusions of law, and decisions of regulatory policy of this Commission.

ORDERED FURTHER, that jurisdiction over this proceeding is expressly retained for the purpose of entering such further order or orders as this Commission may deem proper.

ORDERED FURTHER, any motion for reconsideration, rehearing, or oral argument shall not stay the effectiveness of this order unless expressly ordered by the Commission.

The above by action of the Commission in Administrative Session on the ___ day of December, 2022.

_____	_____
Reece McAlister	Tricia Pridemore
Executive Secretary	Chairwoman
_____	_____
Date	Date

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing POST HEARING BRIEF AND THE PROPOSED ORDER OF GEORGIA POWER COMPANY IN DOCKET NO. 44280 upon all parties listed below via electronic service or by hand delivery and addressed as follows:

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This 8th day of December 2022.

Brandon F. Marzo
Attorney for Georgia Power Company

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