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November 18, 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 on behalf of Georgia Power Company, please find (1) the Rebuttal Testimony of the Panel of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston and Michael B. Robinson, (2) the Rebuttal Testimony of James M. Coyne, (3) the Rebuttal Testimony of Steven M. Fetter, and (4) the Rebuttal Testimony of the Panel of Larry T. Legg and Lee Evans.

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

Sincerely,

Brandon F. Marzo

Enclosure

REBUTTAL TESTIMONY OF

AARON P. ABRAMOVITZ, SARAH P. ADAMS, ADAM D. HOUSTON,
AND MICHAEL B. ROBINSON
ON BEHALF OF GEORGIA POWER COMPANY
GPSC DOCKET NO. 44280

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES, TITLES AND BUSINESS ADDRESS.

A. Aaron P. Abramovitz. I am the Executive Vice President, Chief Financial Officer, and Treasurer for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. Sarah P. Adams. I am the Vice President and Comptroller for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. Adam D. Houston. I am the Assistant Comptroller for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. Michael B. Robinson. I am the Vice President of Planning, Operations and Policy for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

Q. MR. ABRAMOVITZ, MS. ADAMS, MR. HOUSTON, AND MR. ROBINSON, DID YOU PRESENT DIRECT TESTIMONY AND EXHIBITS ON BEHALF OF GEORGIA POWER IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of our testimony is to respond to the recommendations of the Georgia Public Service Commission's ("Commission") Public Interest Advocacy ("PIA") Staff and various Intervenors. To the extent this rebuttal testimony does not address a particular PIA Staff or Intervenor recommendation, that should not be construed as support for such position.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Our testimony requests that the Commission continue the constructive regulatory environment, effectuated through an Alternate Rate Plan ("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 being consistently 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. 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.

Absent an ARP agreed to by the Company, this case will result in a traditional rate case order, which would eliminate the numerous positive attributes of a three-year predictable rate plan, including any sharing of revenues above the top end of the ARP earnings band. This fact notwithstanding, PIA Staff and several Intervenors have proposed radical and harmful modifications to the ARP. PIA Staff goes so far

as to suggest that the Commission impose an earnings cap, which is fundamentally inconsistent with the concept of the ARP sharing mechanism that benefits both customers and the Company. These proposed modifications undercut core aspects of the ARP and, as such, the Commission should reject them.

The positions put forth by PIA Staff and several Intervenors would undermine Georgia's well-established and balanced regulatory structure by drastically reducing the Company's return on equity ("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. Many of these same parties also propose to reduce the equity within 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.

PIA Staff has also asserted that the Company can arbitrarily reduce its Operations and Maintenance ("O&M") expense, as well as substantially reduce or eliminate transmission and distribution investments required to support the long-term reliability and resiliency of our electric system, without considering the long-term impacts to the performance of the electric system for our customers and the state. The Commission must consider the cost of electric service when evaluating Georgia Power's cost to serve our 2.7 million customers, and we have thoughtfully and appropriately balanced our request in this proceeding with both the financial impacts to, and needs of, our customers.

The changes that 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 and to attract the substantial capital

necessary to continue providing our customers with the clean, safe and reliable electric service they deserve and expect. 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.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?

A. Our testimony is organized as follows:

- Section II (pages 5 to 14) discusses financial integrity and access to capital;
- Section III (pages 15 to 19) discusses proposed modifications to the traditional alternate rate plan;
- Section IV (pages 19 to 21) discusses coal combustion residuals asset retirement obligations ("CCR AROs");
- Section V (pages 21 to 23) discusses electric transportation;
- Section VI (pages 23 to 36) discusses O&M adjustments;
- Section VII (pages 36 to 39) discusses other issues, including the revenue forecast, compliance filing requirements, and depreciation;
- Section VIII (pages 39 to 59) discusses the Grid Investment Plan, DERMS, and Rules and Regulations Section G; and
- Section IX (pages 59-61) discusses recent tax legislation.

In addition to our rebuttal testimony, the Company is filing the rebuttal testimony of: (1) Mr. James M. Coyne to address the ROE recommendations and analyses of PIA Staff Witness Gorman and Intervenor Witnesses Pollock, Reno, and Ellis; (2) Mr. Steven Fetter to explain the credit rating impacts of PIA Staff and Intervenor recommendations; and (3) Mr. Larry T. Legg and Mr. Lee Evans to rebut rate design and cost of service issues raised by PIA Staff and Intervenors.

II. FINANCIAL INTEGRITY AND ACCESS TO CAPITAL

Q. WOULD ADOPTION OF PIA STAFF AND INTERVENOR'S COST OF CAPITAL POSITIONS UNDO THIS COMMISSION'S HISTORY OF BALANCED, CONSISTENT AND PREDICTABLE REGULATION AND HARM THE COMPANY'S FINANCIAL INTEGRITY?

A. Yes.

Q. PLEASE EXPLAIN THE IMPORTANCE OF CONSISTENT AND PREDICTABLE REGULATION WITHIN THE CONTEXT OF INVESTOR AND CREDIT PERCEPTIONS AND THE FINANCIAL INTEGRITY OF THE COMPANY.

A. As Mr. Fetter discusses, regulation is a key factor in assessing the future credit risk profile of a utility because, among other things, a state public utility commission determines the nature, amount, and timing of recovery of a utility's cost of service to its customers. Accordingly, the constructive practices and policies of regulatory commissions play a critical role in the overall credit risk profiles of regulated utilities and, ultimately, investors' decisions. As such, it is imperative that state utility commissions understand the financial, economic, and operational elements of an evolving industry, and engage in a fair decision-making process that demonstrates predictability and consistency. As Mr. Fetter has testified, these qualitative factors can represent as much as half of the Company's overall credit rating.

For these reasons, rating agencies look for consistent application of sound economic regulatory principles by utility regulators. 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.

Q. HOW IS THE COMMISSION CURRENTLY VIEWED BY THE FINANCIAL COMMUNITY?

A. S&P Global Market Intelligence (formerly Regulatory Research Associates or "RRA"), a respected commentator on U.S. regulatory policy, rates the Georgia regulatory environment (which goes beyond the Commission to also include state legislative and executive branch policies) as Above Average 2. This places Georgia among the top five of the 53 regulatory jurisdictions that S&P Global Market Intelligence currently evaluates. The beneficial aspect, for both Georgia Power investors and customers, of this ranking is its positive reflection in the credit rating process, which provides the rating agencies with a degree of confidence that the outcome in this rate case will be supportive of the Company's financial integrity. As the rating agencies have stated:

- **S&P**: In a November 18, 2021 report, S&P stated that Georgia Power's multiyear rate plan effective since the 2019 rate case has been "supportive of GPC's credit quality."[1]
- **Moody's**: In an October 26, 2022 report, Moody's stated, "The stable outlook also considers our expectation that the overall regulatory framework in Georgia will remain credit supportive including a constructive outcome on the utility's pending rate case this December;"[2]
- **Fitch**: As stated in an October 4, 2022 report, "Fitch expects a constructive resolution to Georgia Power's pending rate case filing, which proposes a three-year rate plan with rate increases

[1] S&P Research "Georgia Power Company," November 18, 2021.
[2] Moody's Credit Opinion, October 26, 2022.

of $852 million, $107 million, and $45 million effective Jan. 1 of 2023, 2024, and 2025, respectively."[3]

Q. HOW DO CUSTOMERS BENEFIT WHEN THE COMPANY BALANCES THE INTERESTS OF ALL STAKEHOLDERS?

A. Customers benefit when the Company balances the interests of all stakeholders because a financially healthy utility can meet the needs of its customers and is more likely to achieve high levels of reliability and customer satisfaction. Customers also benefit from the Company's operating efficiencies in its efforts to meet investor expectations. The efficiencies gained and the corresponding cost reductions that result from those efforts are provided to customers through savings in rates.

Q. WHAT ELEMENTS OF PIA STAFF'S RECOMMENDATIONS WOULD THREATEN THE COMPANY'S FINANCIAL INTEGRITY?

A. Virtually all of PIA Staff's recommendations would severely harm the Company's financial integrity. Taken individually, Mr. Gorman's recommended 9.45% ROE set point and capital structure of 51% equity, beginning in year 2024, would critically threaten the Company's financial health. The cumulative negative impact of Mr. Gorman's recommendations coupled with those of Messrs. Smith and Trokey would be even more dramatic.

Q. IS THERE A WAY TO EVALUATE THE IMPACTS ON FUNDS FROM OPERATIONS ("FFO") TO DEBT AS A RESULT OF PIA STAFF'S AGGREGATE RECOMMENDATIONS?

A. Yes, 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.

[3] Fitch Affirms Southern Company's and Subsidiary's Ratings, October 4, 2022.

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. 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. PIA Staff's unreasonable recommendations would harm the Company's credit profile, 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.

Q. WHAT ARE THE CREDIT RATING AGENCIES' CURRENT EXPECTATIONS REGARDING THE COMPANY'S FINANCIAL INTEGRITY?

A. 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.

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. However, the rating agencies discuss in their publications the expectation that, beginning in 2024, Georgia Power will remedy its credit profile such that it assumes a position of bolstered strength and adequate credit quality.

Q. WOULD PIA STAFF'S PROPOSED ADJUSTMENTS IMPAIR THE COMPANY'S ABILITY TO IMPROVE ITS CREDIT METRICS OVER TIME?

A. Yes.

Q. WILLMR. GORMAN'S PROPOSED ADJUSTMENTS PRODUCE THE NECESSARY CASH FLOW TO YIELD AN APPROPRIATE CREDIT RATING GOING FORWARD?

A. No. The Company has identified an omission in Mr. Gorman's calculation of expected FFO to debt. Mr. Gorman does not include the correct debt imputations for purposes of the FFO to debt ratio that S&P prescribes in its most recent guidance related to the application of S&P Global Ratings' "Corporate Methodology: Ratios And Adjustments" criteria published April 1, 2019. By excluding more than $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.

Q. WHAT WAS THE OMISSION IN MR. GORMAN'S FFO TO DEBT CREDIT METRIC CALCULATION?

A. 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. These debt imputations are essential adjustments that must be made to arrive at a properly recalculated S&P credit metric.

Q. WHAT ARE DEBT IMPUTATIONS AND WHY DO RATING AGENCIES REQUIRE THEM FOR PURPOSES OF CALCULATING THE CREDIT METRIC "FFO TO DEBT"?

A. Debt imputation is the act of adding debt-like fixed obligations to a utility's "traditional" debt balance when calculating FFO to debt. 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.

Q. HOW DOES S&P OBTAIN THE INFORMATION TO PERFORM SUCH CALCULATIONS?

A. S&P uses the information included on the Company's publicly available balance sheet and accompanying financial disclosures to obtain pertinent information for the proper debt imputation calculation. Georgia Power has no off-balance sheet debt, or any other off-balance sheet components, that the rating agencies use when calculating adjusted debt.

Q. DID MR. GORMAN INCLUDE THIS DEBT IMPUTATION IN HIS FFO TO DEBT CREDIT METRIC CALCULATION?

A. No. In his recalculation of S&P's credit metric, FFO to debt, Mr. Gorman omitted the debt imputation methodology directed by S&P in previously issued authoritative publications. These debt imputations are essential adjustments that must be made to recalculate S&P's credit metric.

In response to the question posed by PIA Staff and Mr. Gorman in data request STF-BAI-1-17, the Company responded as follows:

> **Question**:
>
> Please state whether GPC's regulated retail operations have any off-balance sheet debt such as purchased power agreements and operating leases. If the answer is "yes," provide the amount of each off-balance sheet debt item and estimate the related imputed interest and amortization expense associated with these off-balance sheet debt equivalents specific to GPC's jurisdictional regulated retail electric operations.
>
> **Response**:
>
> No. Georgia Power does not have any off-balance sheet debt. In 2019, Georgia Power adopted the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Codification ("ASC") Topic 842 (as amended), Leases (ASC 842), which requires lessees to recognize leases with a term of greater than 12 months on the balance sheet as lease obligations. With the adoption of the standard, the operating leases historically representing off-balance sheet financing arrangements are now reflected on Georgia Power's balance sheet.

In responding to this question, the Company correctly answered that it does not have any off-balance sheet debt. The Company also clarified that obligations such as purchased power agreements and operating leases are now found on the Company's balance sheet. 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. However, due to the confusion around where these debt-like components are identified, these components were omitted from Mr. Gorman's calculations. Mr. Gorman should have included the debt imputations related to these on-balance sheet debt-like components in his estimated recalculation of S&P credit metrics, as he did in the 2019 rate case.

Q. WHAT AMOUNT OF DEBT IMPUTATION SHOULD HAVE BEEN INCLUDED IN MR. GORMAN'S CALCULATIONS?

A. Based upon the relevant balance sheet accounts, similar to those assessed in S&P's November 18, 2021, Ratings Direct report on Georgia Power,[4] over $5.5 billion of debt imputations should have been adjusted for purposes of Mr. Gorman's estimated recalculation of S&P credit metrics. 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.

Q. DOES THE COMPANY AGREE WITH MR. GORMAN'S CONCLUSION THAT ITS EQUITY RATIO SHOULD BE REDUCED TO 51% BEGINNING IN 2024?

A. No. Although Mr. Gorman acknowledges that the Company's authorized equity ratio was previously increased due to the negative effects of the 2017 Tax Cuts and Jobs Act ("TCJA"), he completely ignores that these negative effects continue today. Instead, he proposes that the Company's equity ratio should be reduced to 51% once Vogtle Unit 4 is placed in service, wrongly assuming that the construction of Vogtle Units 3 and 4 , and not the TCJA, was the catalyst to increase the Company's equity ratio to 56% and should, therefore, be the impetus to reduce it back to 51%.

Q. HOW WAS GEORGIA POWER'S CURRENT 56% EQUITY RATIO DETERMINED IN THE COMPANY'S PRIOR 2019 RATE CASE?

A. 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

[4] STF-NEC-1-1 Attachment AI.

structure to be 56% equity and 44% debt. 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. The Commission further determined that the "proposed capital structure of 56% common equity level is just and reasonable considering all of the evidence presented."

Q. HAVE THERE BEEN ANY CHANGES TO THE TCJA OR ITS NEGATIVE IMPACTS ON THE COMPANY SINCE THE COMMISSION DEEMED THE APPROPRIATE CAPITAL STRUCTURE FOR THE COMPANY TO BE 56% EQUITY AND 44% DEBT?

A. No.

Q. DOES THE COMPANY ANTICIPATE ANY CHANGES TO THE TCJA OR ITS NEGATIVE IMPLICATIONS ON THE COMPANY DURING 2023-2025 THAT WOULD JUSTIFY LOWERING ITS EQUITY RATIO?

A. No.

Q. DOES ANY OTHER WITNESS RECOMMEND A SPECIFIC REDUCTION IN THE EQUITY LEVEL IN THE COMPANY'S CAPITAL STRUCTURE?

A. Yes. Georgia Association of Manufacturers ("GAM") Witness LaConte recommends that 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%. Ms. LaConte's proposal of 53% equity is not based on a careful and accurate analysis of the credit rating 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. Additionally, as mentioned earlier, the 56% equity level set in the 2019 rate case appropriately mitigates the negative credit impacts of the TCJA. 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 its 2019 rate case.

Q. DOES THE COMPANY AGREE WITH MR. GORMAN'S RECOMMENDATION TO REDUCE THE COMPANY'S ROE SET POINT 105 BASIS POINTS TO 9.45%, MRS. LACONTE'S RECOMMENDATION TO REDUCE THE COMPANY'S ROE SET POINT 67 BASIS POINTS TO 9.83%, OR MS. RENO'S RECOMMENDATION TO REDUCE THE COMPANY'S ROE SET POINT 103 BASIS POINTS TO 9.47%?

A. No. Mr. Coyne will address the errors in Mr. Gorman's and Ms. Reno's calculations in this regard. Notwithstanding these errors, their recommendations do not represent current market conditions and would not result in full recovery of the Company's cost of equity. Further, there is no justification for such severe reductions in the Company's cost of equity since the last base rate case. For these reasons, Mr. Gorman and Ms. Reno's recommendations are not supported and are punitive when considering Georgia Power's record of strong performance. The ROE reductions proposed by Mr. Gorman and Ms. Reno are a dramatic departure from the approach employed by this Commission over the past several rate cases and would surely be viewed negatively by the capital markets, as Mr. Fetter has stated in his testimony. A reduction of this magnitude would be an unprecedented change from the consistent and historically constructive regulation for which this Commission has a reputation – one where excellence is recognized and rewarded, not punished.

III. MODIFICATIONS TO TRADITIONAL ALTERNATE RATE PLAN

Q. ARE PIA STAFF'S PROPOSED CHANGES TO THE COMPANY'S ARP CONSISTENT WITH THE CONSTRUCTIVE REGULATORY ENVIRONMENT TYPICAL OF PRIOR ARPS APPROVED BY THIS COMMISSION?

A. No. PIA Staff's collective recommendations radically depart from the previously accepted ARP structure and have the effect of removing the benefits to customers resulting from the Company agreeing to enter an ARP in the first place. Three-year ARPs avoid the potential for more frequent base rate cases, provide rate stability and predictability to customers, provide for customer revenue sharing for earnings above the approved earnings band, encourage the Company to operate efficiently, and signal the type of regulatory consistency viewed favorably by credit rating agencies.

Q. IN WHAT WAY DOES THE COMPANY ASSUME RISK DURING THE THREE-YEAR ACCOUNTING PERIOD?

A. 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. 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. A three-year rate plan 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.

Q. DOES THE COMPANY AGREE WITH PIA STAFF'S RECOMMENDATION TO USE THE TEST PERIOD REVENUE REQUIREMENT FOR PURPOSES OF ESTABLISHING THE FIRST YEAR REVENUE REQUIREMENT OF AN ARP?

A. No. 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. Therefore, setting rates based on the test period would not permit the Company to timely recover its prudently incurred costs in serving customers.

Q. DOES THE COMPANY AGREE WITH PIA STAFF'S RECOMMENDATION TO DEFER AND USE ANY REVENUE SUFFICIENCY BASED ON PIA STAFF'S CALCULATED TEST YEAR AND 2023 REVENUE REQUIREMENT FOR ACCELERATED RECOGNITION OF DEFERRED COSTS?

A. No. Based on the Company's proposal, the Company does not have a projected revenue sufficiency in 2023 to apply to the deferred costs. 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. However, the Company generally agrees with PIA Staff's concept of applying revenue sufficiency in a rate case, in the event there is any, to certain regulatory assets to maintain rate stability for the customers.

Q. WHY IS A LEVELIZED APPROACH MORE APPROPRIATE THAN THE STEP INCREASE APPROACH RECOMMENDED BY PIA STAFF?

A. The levelized approach results in $43 million less being billed to customers than a step increase approach over the three-year ARP. It also balances the needs of both customers and the Company, allowing customers to benefit from three years of stable and predictable rates while allowing the Company to recover its projected revenue deficiency. Rate stability provides customers with a beneficial tool when budgeting for their utility costs and provides a predictable revenue stream for the Company.

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 2023 and 2024, the increase for 2025 would be greater than the levelized amount, and rates would increase more overall during the ARP. In addition, the fluctuation in projected costs year-to-year creates uncertainty for customers. Although the Company shares PIA Staff's interest in rate stability, the Company maintains that levelizing the proposed increases over the three-year ARP is the more appropriate approach for customers.

Q. ARE CUSTOMERS FAIRLY COMPENSATED FOR THE PROJECTED OVER-COLLECTION IN THE FIRST TWO YEARS OF THE LEVELIZATION?

A. Yes. Based on the Company's projections under the levelized revenue requirement, the Company would over-collect in 2023 and 2024 and under-collect in 2025. 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 ("WACC"). This proposed deferral reduces the levelized

revenue requirement requested by the Company and fully amortizes the advancement by the end of 2025.

Q. DO YOU AGREE WITH PIA STAFF'S RECOMMENDATION THAT 100% OF EARNINGS ABOVE THE TOP END OF THE EARNINGS BAND SHOULD BE USED TO ACCELERATE DEFERRED COSTS?

A. No. PIA Staff's proposal amounts to an earnings cap by eliminating any retained revenues earned above the earnings band. This removes any incentive for the Company to exceed the top end of the band and pr does not encourage the Company to maximize efficiencies during the ARP period. In addition, the top end of the earnings band proposed by PIA Staff is set artificially low, at a level below even the Company's cost of equity.

Q. HAS THE EARNINGS SHARING MECHANISM WORKED WELL FOR THE COMPANY AND ITS CUSTOMERS?

A. Yes. As presented in the table on page 130 of the testimony of PIA Staff Witnesses Smith and Trokey, and as stated in our direct testimony, the Company returned approximately $297 million in benefits to customers as a result of the sharing arrangements approved by the Commission in the 2013 and 2019 base rate cases. As the table illustrates, this represents an average of approximately 78% of the earnings above the top of the band being applied to the benefit of customers and 22% of the earnings being retained by the Company since 2014. These benefits have been achieved without compromising superior customer satisfaction or reliability. Notably, the amount customers pay through rates does not increase or decrease when the Company's earnings are within the band, because rates are set on the ROE set point. 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, which can lead to higher earnings that benefit both customers and the Company.

Q. DOES THE COMPANY AGREE WITH COMMERCIAL GROUP WITNESS CHRISS' RECOMMENDATION TO ADJUST THE EARNINGS BAND COMMENSURATE WITH ANY ADJUSTMENT TO THE REQUESTED 11% RETURN ON EQUITY SET POINT?

A. No. 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 set at 9.5% with the top end of the earnings band set at 12.0%.

Q. DO YOU AGREE WITH DOD WITNESS BLANK'S PROPOSAL TO NARROW THE ROE EARNINGS BAND AND REDUCE THE AMOUNT OF EARNINGS ABOVE THE BAND RETAINED BY THE COMPANY?

A. No. 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%. This 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. Narrowing the earnings band may increase risks and uncertainty to customers. Second, Mr. Blank also recommends reducing the Company's portion of any shared earnings above the top of the band, which is not acceptable because it caps the Company's earnings incentive.

IV. CCR AROS

Q. IS THE APPROVAL OF THE COMPANY'S CCR COMPLIANCE PLAN AT ISSUE IN THIS PROCEEDING?

A. No. The Commission-approved 2022 IRP Stipulation in Docket No. 44160 approved the Company's ECS and plan to comply with federal and state CCR regulations, but reserved CCR cost recovery for determination in this rate case. This

includes the method of recovery and the appropriate period over which the Company should recover costs.

Q. DO ANY PARTIES DISAGREE WITH THE COMPANY'S PROPOSAL TO CONTINUE THE CURRENT RECOVERY METHODOLOGY REGARDING CCR ARO COMPLIANCE COSTS APPROVED IN THE COMPANY'S 2019 RATE CASE?

A. All parties generally agree with the current CCR ARO cost recovery methodology except for GAM Witness Pollock, who proposes that the Company should not earn an equity return on the CCR ARO regulatory asset balance. The Company's CCR ARO compliance costs are required to comply with federal and state environmental regulations and are appropriately included in rate base. As such, the Company should be able to timely recover its prudently incurred 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 investments. In addition, his proposed ratemaking treatment contradicts past treatment of ARO compliance costs and such departure from past precedent is unjustified.

Q. DOES THE COMPANY AGREE WITH MR. POLLOCK'S ASSERTION THAT IT SHOULD NOT EARN A RETURN ON EQUITY ON UNRECOVERED CCR COSTS UNTIL SECURITIZATION IS AUTHORIZED?

A. No. Denying the Company the opportunity to recover all of its financing costs on any unrecovered CCR ARO compliance costs amounts to a disallowance and inappropriately and prematurely assumes that such costs were not prudently incurred. 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. 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 happen. Securitization is not needed as this Commission already has all the tools necessary to appropriately balance the needs of our customers and the Company.

V. ELECTRIC TRANSPORTATION

Q. WHAT IS GEORGIA POWER'S ROLE IN SUPPORTING THE DEVELOPMENT OF GEORGIA'S ELECTRIC TRANSPORTATION ("ET") ECOSYSTEM?

A. Georgia Power must be prepared to meet the energy needs of all customers within its service territory. Therefore, we continue to make appropriate investments in the infrastructure and technology needed to support the growth of electric transportation in Georgia that is being driven by customer interest and market demand. These investments include the buildout and upgrade of infrastructure from grid to charger that will enable charging across the state in public, at work, and at home. In limited circumstances, Georgia Power will continue to offer EV charging services as a provider of last resort in underserved areas through the Community Charging Program. As such, Georgia Power will continue to support our state's developing ET ecosystem, which continues to experience economic growth as evidenced by two major EV manufacturing announcements this year.

Q. WHAT IS THE MAKE READY PROGRAM?

A. Georgia Power's Make Ready program helps to remove the biggest financial hurdle of installing electric chargers at a qualifying customer's location by installing, owning, and maintaining the electrical infrastructure behind the meter up to the charger, which typically includes the panel, switchgear, wiring, conduits, and

disconnects. The customer is then responsible for the procurement, installation, maintenance, and energy to serve the EV charging equipment.

Q. WHAT IS GEORGIA POWER'S REQUEST REGARDING THE MAKE READY PROGRAM IN THIS CASE?

A. The Company has requested to invest $27 million per year for each year of the ARP (2023-2025) for infrastructure upgrades in the Make Ready program. As stated in the Company's response to STF-LA-6-19, these capital expenditures include wires, panels, conduit, transformers, and labor.

Q. PLEASE DESCRIBE GEORGIA POWER'S COMMUNITY CHARGING PROGRAM.

A. Georgia Power's Community Charging Program expands the growth of electric vehicle direct current ("DC") fast charging locations by partnering with businesses to host an EV fast charging site where the charging will be made available to the public. Georgia Power installs, operates, and maintains the chargers in this program, which is designed to partner with customers to help grow critical public EV infrastructure across Georgia. The Company primarily operates this program as a provider of last resort to provide public DC fast charging options for EV drivers in areas that lack investment in public DC fast charging. In the 2019 Rate Case, the Commission approved $2 million per year (2020-2022) in spending for the Community Charging program. The Company's request in this case for $3 million per year for each year of the ARP (2023-2025) is intended to maintain the development and deployment of the Community Charging program. The increase in funding requested reflects inflation and the increased cost of labor and equipment.

Q. WILL CONTINUED INVESTMENT IN ET INFRASTRUCTURE AT THE LEVELS GEORGIA POWER REQUESTS PROVIDE ECONOMIC BENEFITS TO CUSTOMERS?

A. Yes. The Company's Rate Impact Measure ("RIM") analysis of the Make Ready program indicates these investments will put downward pressure on rates over the life of the technology, which benefits all customers. The Community Charging program enables greater adoption of these technologies by providing public charging along travel corridors throughout the state, especially in rural and underserved communities that have not received infrastructure investments from the private sector.

VI. O&M ADJUSTMENTS

Q. PLEASE SUMMARIZE MR. MUGRACE'S RECOMMENDED O&M ADJUSTMENTS.

A. Mr. Mugrace recommends reducing the Company's projected O&M expenses by $192 million, $147 million, $137 million, and $169 million in the test year and 2023, 2024, and 2025 rate years, respectively. Mr. Mugrace recommends the Company adjust its projected functional O&M expenses for certain FERC accounts based upon prior historical levels of O&M expenses. Mr. Mugrace also recommends removing certain expenses historically allowed by the Commission from the retail cost of service, such as certain employee labor costs, employee retention costs, Innovation Center costs, and miscellaneous general expenses. Furthermore, Mr. Mugrace recommends the Company reduce its labor expenses based on vacancy rate ratio.

Q. WHY IS A SIMPLE AVERAGE OF HISTORICAL COSTS NOT ALWAYS A GOOD DETERMINANT OF PROJECTED COSTS?

A. 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, labor market, and contractor rates. These 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. In addition, the historical years used by Mr. 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.

Q. PLEASE DESCRIBE THE COMPANY'S O&M BUDGET PROCESS?

A. 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. The Company does not create its budget by simply applying an inflation factor to all the actual, or historic year expenses. Based on the type of expenditure, inflation rates may be applied to derive projected expenses.

Q. DOES THE COMPANY'S O&M REMAIN STATIC OVER TIME?

A. No. The Company has seen significant price increases in nearly all areas of its business. For example, transformer prices have increased over 48% since 2020, wire and cable costs increased 33%, pole line hardware is up 27%, and pole costs have increased 26%. Despite 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"). These are only a few of the items that make up the Company's O&M request. 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. The Company has identified efficiencies in nearly every part of its business while still providing superior customer satisfaction and reliable service to customers.

Q. AS AN EXAMPLE OF WHY SIMPLY ESCALATING HISTORIC COSTS IS INAPPROPRIATE, WHAT IS DRIVING THE INCREASE IN O&M EXPENSES IN CUSTOMER SERVICE AND INFORMATION FOR THE TEST PERIOD AND YEARS 2023 THROUGH 2025?

A. The primary driver for the increase in Customer Service and Information expenses is related to the increase in DSM expenses as a result of the DSM programs approved by the Commission in the 2022 DSM Certification in Docket No. 44161. Because the projected level of DSM expenses are directly attributed to the DSM programs approved by the Commission, historical costs are clearly not a good indicator of the projected expenses for the ARP years reflected in the filing.

Q. ARE WITNESS MUGRACE'S RECOMMENDATIONS REGARDING DSM PROGRAM EXPENSES APPROPRIATE?

A. No. In fact, PIA Staff's panel of Barber, Deitchman, Watkins does not recommend any adjustments to the DSM program expenses.

Q. WHY IS IT INAPPROPRIATE TO REMOVE THE COSTS ASSOCIATED WITH THE INNOVATION CENTER FROM RETAIL COST OF SERVICE AS PROPOSED BY PIA STAFF?

A. The Company's Energy Innovation Center ("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. The EIC is a platform where Georgia Power can 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. 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.

Q. HAVE THE COSTS ASSOCIATED WITH THE ENERGY INNOVATION CENTER PREVIOUSLY BEEN APPROVED BY THE COMMISSION IN RETAIL COST OF SERVICE?

A. Yes.

Q. WHY IS IT INAPPROPRIATE TO REMOVE THE SERVICE AWARDS AND RECREATION COSTS FROM RETAIL COST OF SERVICE?

A. The 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. As stated in STF-PCMG-2-12, the costs listed as recreation costs are actually meals and travel expenses that were inadvertently budgeted to FERC account 926 instead of FERC account 921. These are not a "new" set of costs as the Company incurred similar expenses in prior periods, which were correctly recorded to FERC account 921.

Q. HAVE THE SERVICE AWARDS AND MEALS AND TRAVEL EXPENSES PREVIOUSLY BEEN APPROVED BY THE COMMISSION IN RETAIL COST OF SERVICE?

A. Yes.

Q. WHY IS IT INAPPROPRIATE TO REMOVE MISCELLANEOUS GENERAL EXPENSES INCLUDING ASSOCIATION DUES, COMMUNITY SERVICE, AND EXPERIMENTAL COSTS FROM RETAIL COST OF SERVICE?

A. Contrary to the assertion of PIA Staff Witness Mugrace, these items are necessary costs incurred in operating the business and our customers benefit from these 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. Costs associated with community organizations, community development,

economic development and other business issues 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.

Q. HAVE MISCELLANEOUS GENERAL EXPENSES INCLUDING ASSOCIATION DUES, COMMUNITY SERVICE, AND EXPERIMENTAL COSTS PREVIOUSLY BEEN APPROVED BY THE COMMISSION IN RETAIL COST OF SERVICE?

A. Yes.

Q. PLEASE DESCRIBE HOW THE COMPANY CALCULATED THE INCREMENTAL INFLATION ASSOCIATED WITH ITS O&M EXPENSES?

A. 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. 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. The adjustments were recorded at a summary account level across several FERC accounts as provided in STF-PCMG-1-5. Items such as benefits, incentive pay, insurance, and parity were excluded from the adjustment.

Q. WHY IS STAFF'S COMPARISON AND THE RESULTING RECOMMENDED ADJUSTMENT OF INCREMENTAL INFLATION INAPPROPRIATE?

A. Although Mr. Mugrace states that the ECI is an appropriate source of inflation rates for labor costs, 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. In order to appropriately calculate the 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. In addition, Mr. Mugrace did not carry forward the incremental inflation adjustment calculated in Year 1 to the subsequent years, which caused the impact in future years to be understated. Since the escalation indexes are increases from the prior year, any incremental inflation adjustments from the prior year need to be accounted for in the calculation of incremental inflation in a given year.

Q. PLEASE DESCRIBE THE COMPANY'S BUDGETED HEADCOUNT IN THE FORECASTED PERIODS?

A. The Company budgeted its headcount and total labor costs, including internal and contract labor as well as overtime, at the level needed to operate its business and, therefore, there is no headcount vacancy reflected in the Company's forecast.

Q. IF THE COMPANY IS UNABLE TO HIRE THE FULL NUMBER OF EMPLOYEES BUDGETED TO PERFORM ITS OPERATIONS, HOW DOES THE COMPANY CONTINUE TO MANAGE ITS BUSINESS?

A. The Company fills open positions with overtime labor from the existing workforce or hires additional contract labor to perform the necessary work if it is unable to hire the full number of employees budgeted. In this example, while internal labor costs decrease, overtime and contract labor increase to offset the reduction.

Q. WHAT INCORRECT LABOR BUDGET ASSUMPTIONS OR ERRORS WERE INCLUDED IN MR. MUGRACE'S TESTIMONY?

A. Mr. Mugrace makes several errors based on flawed assumptions about how and where labor dollars are budgeted. The labor dollars referenced by Mr. Mugrace

throughout his testimony only capture contract labor dollars and not internal labor dollars. There are internal labor dollars included within the functional O&M expenses from which Mr. Mugrace attempted to remove all labor dollars to determine non-labor expenses. The results of Mr. Mugrace's adjustments are significantly flawed because he failed to remove the internal labor dollars in his analysis. Additionally, the costs associated with the Performance Pay Program ("PPP") and payroll taxes are removed from contract labor although the Company provides neither PPP nor payroll taxes for contract labor. In some instances, there also appear to be inconsistencies where Mr. Mugrace only applied adjustments to the test year, while for other years, the adjustments were only applied to years 2023 through 2025. For example, Mr. Mugrace recommends reducing the Company's proposed incremental inflation expenses for years 2023 through 2025 but does not recommend a corresponding adjustment to the test year, which shows an increase in O&M expenses resulting from his analysis.

Q. WHY IS IT INAPPROPRIATE TO REMOVE CERTAIN EMPLOYEE LABOR COSTS FROM RETAIL COST OF SERVICE?

A. 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. 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 workforce.

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. 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. 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.

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. 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. Further, these costs offset the potential future expenses that would be incurred to recruit, develop and train substitute employees for these key roles.

Q. HAVE THESE EMPLOYEE LABOR COSTS PREVIOUSLY BEEN APPROVED BY THE COMMISSION IN RETAIL COST OF SERVICE?

A. Yes.

Q. WHAT IS THE GOAL OF GEORGIA POWER'S EMPLOYEE COMPENSATION PROGRAM?

A. To provide its award-winning service to customers, Georgia Power must attract and retain highly skilled employees. Therefore, 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.

Q. WHAT IS PIA STAFF'S CONCERN WITH THE COMPANY'S PROPOSED EMPLOYEE COMPENSATION PROGRAM?

A. According to the testimony of Messrs. Smith, Trokey, and Mugrace, it appears that PIA Staff believes 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.

Q. DOES THE COMPANY AGREE WITH THE DISALLOWANCES FOR THE EMPLOYEE COMPENSATION PROGRAM PROPOSED BY PIA STAFF?

A. No. The Company's existing compensation policy is necessary to attract, motivate, and retain a highly skilled, dedicated workforce, and to provide customers with clean, safe, and reliable service while efficiently managing costs. 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 was 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. It would result in higher fixed costs and poor alignment of all stakeholders' interests, including customers.

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."

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.

Further, the payroll tax expenses associated with stock-based compensation are also a prudently incurred cost of doing business and, therefore, should be recovered from customers. However, Messrs. Smith and Trokey applied both the Federal Insurance Contributions Act ("FICA") and Medicare portions of payroll tax to the stock-based compensation adjustment when calculating their payroll tax expense adjustment to be excluded from retail cost of service. As they noted on schedule E-5 in PIA Staff's Exhibit_(RS-RT-2), it is likely that employees who are eligible for the Company's stock-based compensation programs would have annual salaries above the projected FICA threshold. Therefore, it is appropriate to apply only the Medicare portion of payroll tax to the stock-based compensation expense when calculating the applicable payroll tax expense adjustment.

Q. WHY DOES THE COMPANY PROVIDE LONG-TERM INCENTIVE BASED COMPENSATION?

A. The long-term incentive based at-risk compensation program incentivizes employees to make decisions that are in the long-term best interest of customers and the Company. 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. 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.

Q. WHY IS IT IMPORTANT THAT AN INCENTIVE COMPENSATION PLAN INCLUDE BOTH OPERATIONAL AND FINANCIAL GOALS?

A. Georgia Power seeks 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 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. 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.

Q. HOW DO THE ELEMENTS OF GEORGIA POWER'S COMPENSATION PROGRAM THAT ARE BASED ON FINANCIAL OBJECTIVES PROVIDE BENEFITS TO CUSTOMERS?

A. 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.

Q. WHAT MIGHT GEORGIA POWER AND ITS CUSTOMERS EXPERIENCE IF THE COMPANY IS UNABLE TO RECOVER THESE COSTS?

A. 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 employees to focus solely on operational performance with no balance or accountability to cost (causing employees to improve operational performance and customer satisfaction regardless of the financial cost to do so). Georgia Power strongly believes this imbalance is not in

the best interests of customers, and also believes this will lead to higher rate increases for customers in the future with little to no benefit or improvement to operations.

Q. DOES THE COMPANY AGREE WITH MESSRS. SMITH AND TROKEY'S STATEMENT THAT "THE OBJECTIVES OF MAXIMIZING SHAREHOLDER VALUE ON THE ONE HAND AND MINIMIZING COSTS TO RATEPAYERS ON THE OTHER HAND, ARE GENERALLY OPPOSED TO EACH OTHER"?

A. No. To deliver value to shareholders, the Company must constantly find ways to run its business as efficiently as possible without sacrificing customer satisfaction and reliability. The efficiencies gained and the cost reductions resulting from those efforts are returned to customers through lower revenue requirements. Therefore, many of the Company's actions to increase shareholder value will result in lower costs and increased value to customers.

VII. OTHER ISSUES

Revenue Forecast

Q. DOES THE COMPANY AGREE WITH PIA STAFF'S RECOMMENDED REDUCTION TO THE COMPANY'S PROJECTED REVENUE FORECAST?

A. No. 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. In addition, PIA Staff agreed that the Company's method was reasonable and did not identify any errors or corrections in the Company's filing. PIA Staff simply offered an alternative for Commission consideration.

Q. WHAT IS THE COMPANY'S POSITION REGARDING PIA STAFF'S RECOMMENDATIONS TO ESTABLISH A REQUIREMENT FOR FILING DETAILED REVENUE FORECAST TESTIMONY AND WORKPAPERS IN FUTURE RATE CASES?

A. Should the Commission believe a modification to the Base Rate Case Minimum Filing Requirements ("MFRs") is warranted to address the revenue forecast, the Company would support working with the Staff to make the necessary revisions.

Compliance Filing Requirements

Q. DOES THE COMPANY AGREE WITH PIA STAFF'S RECOMMENDED DATA REVISIONS TO THE CURRENT ANNUAL COMPLIANCE FILING REQUIREMENTS?

A. No. 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. 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.

Depreciation

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH PIA STAFF'S WITNESS KAUFMAN'S DEPRECIATION RECOMENDATION.

A. Although the Company agrees with Mr. Kaufman's proposed depreciation life extension of Plant Hatch, there are some important areas of disagreement with other aspects of his testimony, as described below:

- Contingencies should not be removed from production dismantling costs.
- The lives for hydro, transmission, distribution, and general plant should not be extended.
- Mr. Kaufman fails to update certain components of the calculations used for extending the lives of certain generating units and Transmission, Distribution, and General plant.

In addition, PIA Staff incorrectly applies Mr. Kaufman's proposed depreciation rates for Transmission, Distribution and General plant easements to the appropriate plant in service balances.

Q. CAN YOU BRIEFLY DESCRIBE THE CONCERNS YOU HAVE REGARDING PIA STAFF'S DISMANTLEMENT COST ASSUMPTIONS?

A. PIA Staff Witness Kaufman removes contingency from plant dismantlement cost estimates for coal and gas production facilities. He concludes that contingency represents "unexpected outcomes" and therefore, should be removed from the depreciation expense calculations for the Company's coal and gas plants.

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.

Q. ARE THERE FACTORS THAT THE COMPANY MUST CONSIDER FOR CURRENT AND FUTURE PLANT DISMANTLEMENTS THAT HAVE NOT AFFECTED HISTORIC PLANT DISMANTLEMENTS?

A. Yes. 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.

Q. HAVE HISTORIC DISMANTLEMENT COST ESTIMATES, INCLUDING CONTINGENCY, PREVIOUSLY BEEN APPROVED BY THE COMMISSION IN RETAIL COST OF SERVICE?

A. Yes.

VIII. GRID INVESTMENT PLAN, DERMS, AND RULES AND REGULATIONS SECTION G

Transmission Grid Investment

Q. HAS THE COMPANY USED OBJECTIVE APPROACHES TO DETERMINE WHICH EQUIPMENT SHOULD BE REPLACED AS PART OF THE GRID INVESTMENT PLAN AS RECOMMENDED BY STAFF WITNESSES ALVAREZ, STEPHENS, AND RANA?

A. Yes, 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. While the industry expected life for transformers and breakers is 35 years and 25 years, respectively, the Company has been able to extend the life of equipment beyond its industry expected life through its existing comprehensive maintenance practices. The Company's expected life for transformers and breakers is 50 years and 35 years, respectively.

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 failure will occur on the system. Over the last ten years, 196 substation transformers failed in-service at an average age of 43 years, which is lower than the Company expected life for this asset. Of these 196 substation transformers, 108 failed (55%) after passing such diagnostic tests and inspections. Therefore, the Company's experience to date informed its recommendation to replace transmission assets through the Grid Investment Program that have or will exceed their Company expected life by 2031 rather than solely relying on the results of the Company's routine diagnostic tests and inspections.

Q. WILL TRANSMISSION INVESTMENTS IN THE GRID INVESTMENT PLAN PREVENT SYSTEM RELIABILITY DETERIORATION?

A. Yes. Transmission investments pursuant to the Company's Grid Investment Plan are intended to replace assets that have or will have exceeded their Company expected life by the end of the plan. These assets are being replaced to prevent reliability challenges associated with aged transmission assets. Based on the Company's operational experience and common understanding, the likelihood of failure for transmission assets included in the plan increases as the assets age beyond their expected life. Due to the large percentage of transmission equipment that is beyond or nearing its Company expected life, the Company designed the Grid Investment Plan to target the reasonable replacement of such assets to prevent transmission system reliability deterioration across the system. If these replacements are not undertaken, system reliability will be negatively impacted due to increased failures of aged equipment. Such failures can be catastrophic and simultaneous in nature. Replacing these aged assets will reduce the number of emergency failures, mitigate system operation reliability concerns, avoid higher maintenance and replacement costs, and ensure the safety of the general public and the Company's employees.

Q. WOULD IT BE PRACTICAL FOR THE COMPANY TO CONDUCT AND RELY ON A COST-BENEFIT ANALYSIS FOR TRANSMISSION INVESTMENTS INCLUDED IN THE GRID INVESTMENT PLAN AS RECOMMENDED BY PIA STAFF WITNESSES?

A. No, 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 and the number of variables that could change suddenly in such a study. The transmission system has a wide variety of components and factors that impact its operation, such as system loading and flows, facility and generation outages, and weather. 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. 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 an analysis would be questionable, at best. 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.

Q. DOES THE COMPANY'S DATA SUPPORT STAFF WITNESS STEPHENS' ASSERTION THAT TRANSMISSION EQUIPMENT CAN OPERATE SAFELY AND RELIABLY PAST EXPECTED LIFE FOR UP TO 100 YEARS?

A. No. Witness Stephens' example of a single 99-year-old transformer on Georgia Power's system should not be used as a basis for the assumption that the Company's entire transformer fleet can or should operate that far beyond Company expected life. The tables below represent transmission and distribution substation equipment

within 10 years of the oldest vintages for transmission and distribution substation equipment on Georgia Power's system. The vintages shown in Tables 2 and 3 represent a significantly small portion of each equipment category, with the highest vintage percentage being only 2% of the entire population for that equipment type. More importantly, power transformers are less than 0.2% for both substation types.

TABLE 2: FERC Account 353 - Transmission Station Equipment

Equipment Type	Oldest Vintage	Percentage of Total Population (within 10 years of oldest vintage)
Circuit Breakers	1945	2.08868%
Other	1930	0.00031%
Power Transformer	1923	0.16695%
Relay	1955	1.37020%
Voltage Regulator	1938	0.00000%

TABLE 3: FERC Account 362 – Distribution Station Equipment

Equipment Type	Oldest Vintage	Percentage of Total Population (within 10 years of oldest vintage)
Circuit Breakers	1946	1.72047%
Other	1926	0.00408%
Power Transformer	1926	0.11719%
Relay	1931	0.02160%
Voltage Regulator	1948	0.23549%

This data indicates that while a very small portion of substation equipment can operate well past Company expected life, Georgia Power should not expect the overwhelming majority of its transmission and distribution assets to operate safely and reliably for this long. As mentioned previously, the Company's data over the last ten years shows that substation transformers have failed at an average age of 43 years, which is well below the timeframe that Mr. Stephens suggests that equipment can remain in operation. Furthermore, the average age of failure for transformers over the last ten years (43 years) is past industry expected life (35 years), but earlier than the age (50 years) at which this equipment will be replaced within the Grid Investment Plan. Given the large number of transmission assets that will exceed their Company expected life in the near future, replacement within the

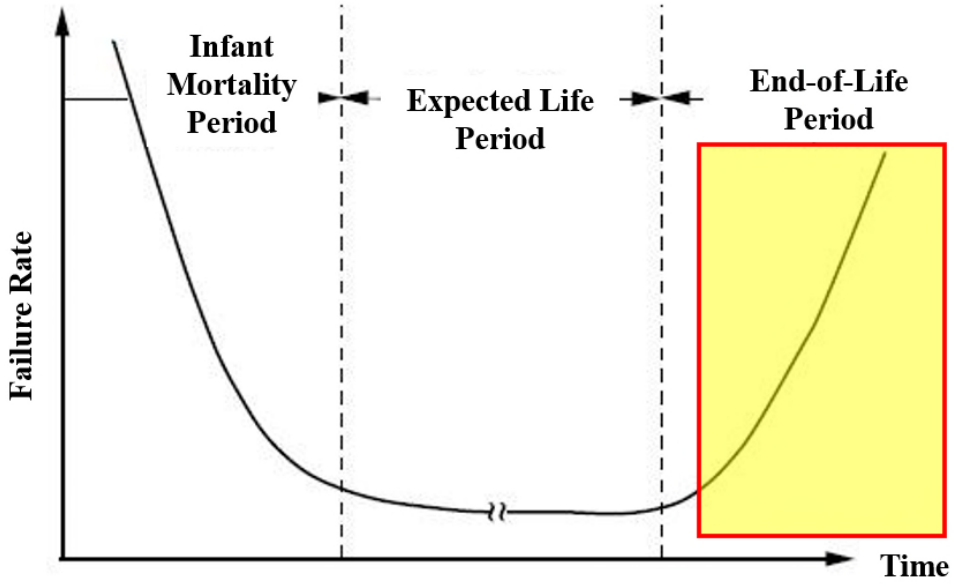
Grid Investment Plan, as designed, is a better solution for the transmission system than simply operating these assets for an unknown period of time until they fail. If the Company does not continue with these investments, the risk of catastrophic equipment failure along with facility and customer outages will increase.

Q. IS THE COMPANY PERFORMING PREEMPTIVE REPLACEMENTS FOR TRANSMISSION EQUIPMENT INCLUDED IN THE GRID INVESTMENT PLAN?

A. No. The Company disagrees with Staff Witnesses Alvarez and Stephens' characterization of the Company's Grid Investment Plan strategy for transmission assets as "preemptive replacement." The Company relied on its extensive operational and maintenance experience, outage and failure history, and ability to extend asset expected life to determine the age at which it should replace transmission assets within the Grid Investment Plan. In addition, the Company reviewed, analyzed, and compared its replacement assumptions against industry expected life ages for the transmission equipment to be replaced in the Grid Investment Plan.

As the Company testified during direct hearings, the bathtub curve is utilized to determine the variation of equipment failure rate with respect to time. The bathtub curve presented in Witness Alvarez and Stephens' testimony is based upon the *estimated useful life* of a hypothetical piece of equipment. In contrast, the bathtub curve, as illustrated in Figure 1 below, is based on the *expected life of an asset*, which is defined as the life expectancy of the Company's equipment. The life expectancy of equipment is supported by internal maintenance procedures, past experiences, equipment specifications, and monitoring of equipment. It is important to note that estimated useful life and expected life are two very separate and distinct terms.

FIGURE 1: Bathtub Curve for Expected Life



Witnesses Alvarez and Stephens mistakenly point to the *middle* of their estimated useful life bathtub curve and misrepresent the point at which the Company is replacing transmission equipment as part of the Grid Investment Plan. However, the Company is replacing equipment in the "end-of-life period" where failures occur at an exponential rate due to age-related degradation of equipment. The Company is strategically targeting transmission projects within this "end-of-life period" in a controlled and planned manner to prevent customer interruptions, catastrophic equipment failure, and better manage replacement costs for customers. As mentioned in several discovery requests, the cost of replacing transmission equipment that has catastrophically failed is 2 to 13 times the cost of replacing this equipment in a planned manner. Within this context and background, the Company strongly maintains that it is not performing preemptive replacement on its transmission equipment as part of its Grid Investment Plan.

Q. WHEN FAILURES OCCUR FOR AGED EQUIPMENT ON THE SYSTEM, SHOULD THE COMPANY SOLELY DEPEND ON SPARE EQUIPMENT BEING AVAILABLE TO REPLACE THE FAILED EQUIPMENT AS SUGGESTED BY STAFF WITNESSES?

A. No. Solely depending on spare equipment to supplement failed equipment would present both operational and supply chain challenges if failures occur. The Company's equipment stock levels are aimed to address emergency replacements based on historical failure rates and other factors. The current stock levels are agreed upon by Integrated Transmission System ("ITS") Participants, which along with customers, bear the cost of the spare equipment pool. If the Grid Investment Plan is not continued, 44% of substation transformers and 37% of substation breakers will have exceeded their Company expected life by 2031. With having such a large amount of equipment at or nearing the "end-of-life" period at the same time, the Company is concerned that the existing spare equipment stock will not be able to keep up with the replacement demand for failed equipment. For example, the Company's current stock levels for substation transformers represents 3% of the total population transformers on the system. Furthermore, there are 171 different types of transformers on Georgia Power's system. The Company currently only has spare transformers available for 38 of the 171 transformer types, with many of the available transformer spare counts being limited to only one unit on hand.

Due to industry supply chain challenges, the lead times for all substation equipment are longer than the Company has seen in many years, with average substation transformer lead times increasing from approximately six months to three years. These lead times continue to grow as other utilities invest in their system and global pressures on the supply-chain for grid infrastructure continue. As transmission equipment gets older and failure rates increase, the Company and customers will be negatively impacted given the number of spares in existing inventory. The

Company could choose to increase its spare equipment pool, but this would also negatively impact customers, as keeping too much spare inventory would lead to higher expenditures and higher carrying costs. Depending on spare equipment means that the Company would wait for equipment to fail before it acts. The Company is strongly opposed to such an approach. The Grid Investment Plan offers a controlled, programmatic, multi-year approach to replacing aging transmission assets in a way that reasonably accounts for these operational and supply chain considerations.

Distribution Grid Investment

Q. DOES THE COMPANY AGREE WITH STAFF'S PROPOSED REDUCTIONS TO THE DISTRIBUTION PORTION OF THE GRID INVESTMENT PLAN, AND THE OVERALL ASSERTION "THERE IS NO PENDING RELIABILITY EMERGENCY"?

A. No, the Company does not agree that the Basic Insulation Level ("BIL") and Undergrounding investment packages, which make up approximately 85% of Distribution Grid investments, should be removed from the program. Nor does the Company agree with the statement that "there is no pending reliability emergency."[5] Georgia Power's system reliability will continue to worsen every year that investments are not made. Between 2013 and 2021,[6] the Company's system average interruption duration index ("SAIDI") worsened by approximately 44% and system average interruption frequency index ("SAIFI") worsened by approximately 10%. 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

[5] Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 2, lines 23 – 24.
[6] Georgia Power reliability performance 2014 - 2021, as reported by the Energy Information Administration.

customer experience[7] due to more frequent and longer outages, as well as increases in the economic cost incurred by customers.

It is within this context, and with extreme care, that the Company created the Distribution portion of the Grid Investment Plan, which is designed to ensure lasting reliability improvements while minimizing the total cost to the customer. Removing the BIL and Undergrounding investment packages from the Grid Investment Plan would result in significantly longer and more frequent outages across the system, as these packages are the best way to permanently address the root causes of outages on these feeders. In the absence of 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. Therefore, the Staff's recommendations would maintain the system-level SAIDI at third quartile levels.

Q. IS THE REVISION TO THE COMPANY'S END-STATE SAIDI FOR THE DISTRIBUTION PORTION OF THE GRID INVESTMENT PLAN A REFLECTION OF REDUCED RELIABILITY EXPECTATIONS, AS CLAIMED BY STAFF?

A. No. 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. In fact, the Company has seen better than expected reliability improvements from the set of investments that have completed construction. Initial results indicate an improvement of approximately 65% in both SAIDI and SAIFI for Grid projects that have been completed for over a year and cycled through both a winter and summer

[7] Response to STF-WG-2-7(j), Docket No. 42516.

peak since completion.[8] The investments are working and are delivering improved reliability for Georgia Power's customers.

As outlined in our direct testimony, the Company refined certain components of the Grid Investment Plan based on insights and lessons learned in the first three years of the program:

- Georgia Power confirmed that the overall strategy and economic rationale supporting the Grid Investment Plan is optimal for customers. The specific investment packages deployed are producing expected benefits and delivering positive results.

- The total cost required to deliver individual investments is higher than the Company originally projected because of increases in scope (*e.g.*, additional automation devices required) and in the cost of work (*e.g.*, inflation, COVID shortages).

- Undergrounding remains the most effective solution for improving customer reliability but, as investment costs have increased across the program, the use of Undergrounding should be carefully evaluated to ensure it is used only where it is the most efficient solution.

Given the learnings above, the Company reassessed and refreshed the Distribution portion of the Grid Investment Plan, using 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. 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 is still first quartile results compared to industry peers. The Company considers this intermittent refinement of the 10-year Grid Investment Plan to be essential for ensuring that customer capital is managed responsibly.

[8] STF-WG-2-36 Trade Secret Attachment provided in response to STF-WG-2-36(c).

Q. WHY DID THE COMPANY ELECT TO OPTIMIZE THE GRID INVESTMENT PLAN AT THE SYSTEM RATHER THAN FEEDER LEVEL?

A. 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. In other words, the explicit 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. 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.

Q. DOES THE COMPANY'S DISTRIBUTION PORTION OF THE GRID INVESTMENT PLAN IGNORE A FEEDER-BY-FEEDER ANALYSIS AS SUGGESTED BY STAFF WITNESSES ALVAREZ AND STEPHENS?

A. No. Staff Witnesses Alvarez and Stephens propose that the Company conduct a root cause analysis for every feeder on the Company's system, which implies that the Company has not done such analysis. However, this is a misconception. In fact, each and every distribution investment within the Grid Investment Plan is evaluated on a feeder-by-feeder basis with a root cause analysis. The Company does exactly the level of analysis suggested by Staff Witnesses Alvarez and Stephens.

Q. PLEASE DESCRIBE THE FEEDER-LEVEL ROOT CAUSE ANALYSIS THE COMPANY CONDUCTS FOR POTENTIAL GRID INVESTMENTS.

A. To evaluate a distribution feeder for the Grid Investment Plan, first, the Company aggregates all the pertinent and available data across the system. This data begins with five years of total reliability performance for each feeder as measured by

SAIDI, SAIFI, customer minutes of interruption (CMI), and frequency of different outage event causes. The initial 'hurdle' for any feeder to qualify for investment is that the feeder has had sustained poor performance over the past five years.

The Company then undertakes a second evaluation to determine the root causes of outages on each feeder. In this step, the Company disaggregates every feeder's reliability performance to understand the events that caused those outages. For example, the Company evaluates what percentage of a feeder's outages were the result of vegetation, vehicles, animals, or weather and how that percentage compares to the rest of the system. 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 that particular cause(s) than the system average. 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. 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.

Q. PLEASE DESCRIBE HOW THE COMPANY SELECTS FEEDERS FOR INVESTMENT AFTER CONDUCTING THE ROOT CAUSE ANALYSIS.

A. 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. The cost and benefit for each investment will vary depending on unique characteristics of each feeder, such as starting reliability performance and number of line miles to be worked.

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. To do this, the Company evaluates the total cost to all Georgia Power customers of each potential investment plan and selects the plan that minimizes total cost to customers across the system– inclusive of the cost of investment, the cost of remaining outages, and the cost of O&M that customers bear. In this fashion, the Company considers the direct cost of investments as well as the costs customers bear from increased outages related to not investing in some potential investments. The Company acknowledges that it has an obligation to provide reliable electric service and minimize outages for all customers and, therefore, must evaluate the total cost to deliver the best plan for all of its 2.7 million customers.

Q. DID STAFF WITNESSES ALVAREZ AND STEPHENS PROVIDE ADEQUATE SUPPORT FOR THEIR ASSERTION THAT BIL AND UNDERGROUNDING ARE NOT COST EFFECTIVE?

A. No, the Company fervently disagrees with Staff's assertions that the BIL and Undergrounding packages are not cost-effective.[9] In executing their cost effectiveness analysis, Staff systematically underestimated investment benefits by not accurately representing the cost to customers of foregoing BIL and Undergrounding:

- First, Staff Witnesses Alvarez and Stephens did not account for the continued reliability degradation that customers will experience if feeders selected for BIL or Undergrounding are denied investment, underestimating the economic cost to customers of the increased outages.

- Second, 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.

[9] Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 3, line 25.

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 has the utmost confidence 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.

Q. DID STAFF WITNESSES ALVAREZ AND STEPHENS PROVIDE ADEQUATE SUPPORT FOR THEIR RECOMMENDATION THAT THE COMPANY INCREASE VEGETATION MANAGEMENT IN LIEU OF THE GRID INVESTMENT PLAN?

A. No. Staff Witnesses Alvarez and Stephens offered no independent analysis to validate the assertion that increased vegetation management is an effective alternative to the BIL or Undergrounding Grid Investment Plan packages.[10] 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. During cross examination, Mr. Stephens himself acknowledged that he had made an assumption about vegetation management as a cost-effective alternative.[11]

Staff did not explain how vegetation management could generate the same expected level of reliability improvement as the dedicated investment packages included in the Grid Investment Plan. Georgia Power's current vegetation management program is designed to maintain reliability, not improve it. In addition, Mr. Stephens confirmed during cross examination that no analysis had been done to determine how much it would cost to actually improve reliability through

[10] Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 47, lines 15 – 16.
[11] PSC Docket No.44280 GPC 2022 Rate Case (11/09/2022); Day 2 of Cross Examination, time stamp 1:37:15.

vegetation management.[12] Further, 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.

Finally, Witnesses Alvarez and Stephens proposed a legislated expansion of utility rights of way as a potential approach to improving reliability.[13] However, 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. 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.

Q. DID STAFF PROVIDE ADEQUATE SUPPORT FOR THEIR RECOMMENDATION THAT THE COMPANY IMPROVE ITS WORST PERFORMING FEEDER PROGRAM IN LIEU OF THE GRID INVESTMENT PLAN?

A. No. As with its vegetation management recommendation, Staff failed to conduct the analysis required to validate the recommendation that the Company should focus its attention only on feeders that are performing 2.5 times worse than average as part of its 'Worst Performing Feeder' program.[14] This lack of analysis is inconsistent with Witnesses Alvarez and Stephens' own assertions that grid investments should only ever be made if they are cost effective at the feeder level.

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. For many of these feeders, BIL and Undergrounding would be the best solution that would address root causes – yet both of these are investment packages within the

[12] PSC Docket No.44280 GPC 2022 Rate Case (11/09/2022); Day 2 of Cross Examination, time stamp 1:35:06.
[13] Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 50, lines 2 – 3.
[14] Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 45, lines 1 – 2.

Grid Investment Program that Staff has proposed for removal. Moreover, Staff did not consider the economic or O&M cost for outages that will continue to be experienced on feeders that do not meet PIA Staff's 'worst performing' criteria.

Q. PLEASE EXPLAIN WHY A MORE ROBUST WORST PERFORMING FEEDER PROGRAM WOULD NOT BE A DIFFERENTIATED ALTERNATIVE TO THE GRID INVESTMENT PLAN.

A. The Distribution portion of the Company's Grid Investment Plan already encompasses the key qualities that Staff indicates should be part of a more robust 'Worst Performing Feeder' program. This includes clear and repeatable criteria to identify poor-performing feeders, a dedicated budget and associated personnel to administer the program, and standard tracking and reporting on the program's progress.

First, the Staff Witnesses Alvarez and Stephens recommend establishing "clear criteria for identifying circuits for additional attention,"[15] and that the Company "compute one or more reliability metrics for each circuit to enable the identification of poor performers."[16] As is presented in the Customer Benefit Analysis,[17] the Company has clear and specific criteria for each Distribution investment package in the Grid Investment Program. 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 the 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.

Second, Staff recommends "that specific budgets for the program be established," and that there be designated "personnel / organizational accountabilities for

[15] Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 53, line 10.
[16] Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 50, lines 13 – 15.
[17] STF-WG-2-8 Trade Secret Attachment in response to STF-WG-2-8, updated k-factor, Table I.2.

program administration."[18] The Distribution portion of the Grid Investment Plan has a designated budget and designated personnel. In the 2019 Rate Case, the first three years of the Distribution portion of the Grid Investment Plan were 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.

Last, Staff Witnesses Alvarez and Stephens recommend "standards for tracking spending, projects, and results."[19] 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. The Company reports on the Grid Investment Program performance during the Company's rate case and makes itself available to respond to any data requests on the Grid Investment Program, as evidenced by the substantial volume of Grid-related data requests that were responded to in the current case. The fact that the Company has robust standards for tracking spending, projects, and results is evidenced by the adjustments made by the Company in the overall plan and optimal range for investment.

The Distribution portion of the Grid Investment Plan encompasses the very qualities that Staff recommends should be part of the Company's 'Worst Performing Feeder' program and should be approved as is without modification.

DERMS and Rules and Regulations Section G Recommendation

Q. ARE CURRENT SOFTWARE SYSTEMS SUFFICIENT ENOUGH TO EFFICIENTLY MANAGE THE GROWING AMOUNT OF DISTRIBUTED

[18] Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 53, lines 13 – 14.
[19] Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 53, lines 12 – 13.

ENERGY RESOURCES ("DER") THAT WILL BE INTERCONNECTED ON THE SYSTEM?

A. No. While current software systems allow for the monitoring of power flows and equipment statuses, they lack the enhanced monitoring and operational capabilities necessary to allow for the optimization of an electric system that takes full advantage of a proliferation of DER. The applications currently in place are not capable of managing the substantial number of DERs expected to connect to the grid in the coming years. As more DER are added to the system, it is essential for the Company to 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 also negatively impact power quality and reliability. Further, a system operator will not be able to process the significant amount of data coming in and make informed decisions quickly enough to optimize grid operation if using current software systems.

In contrast, a DERMS fully integrated with the Company's other grid control systems unlocks the potential to continually optimize larger portions of the grid and solve for a variety of constraints, such as economic dispatch, Volt/VAR optimization, and reliability. 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 will allow for maturation of the solution while thousands or tens of thousands of additional discrete DER are connected to the grid. If DER growth is unrestricted without the installation of DERMS, the Company risks a loss of grid control, which would compromise grid reliability and stability. 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.

Q. COULD THE COMPANY DELAY ITS DERMS PROGRAM UNTIL DER ADOPTION IS HIGHER?

A. No. There are significant risks to grid stability if the Company were to delay implementing DERMS. Beginning implementation of a DERMS solution now allows for the full DERMS capabilities envisioned by the Company 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.

Q. IS THE INTENT BEHIND THE COMPANY'S PROPOSED EDITS TO SECTION G OF THE RULES AND REGULATIONS TO REQUIRE UNCONDITIONAL ACCESS AND CONTROL OF CUSTOMER GENERATORS, AS STAFF SUGGESTS?

A. No. 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. The proposed requirement to allow for communication and increased visibility to DERs operating in parallel with the system is critical to maintaining the system's safety and reliability. 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. Notably, the Company has only requested this change for customer generation facilities sized 250 kW and above that operate in parallel with the Company's electric system for more than 100 milliseconds.

Q. DID THE COMPANY INTEND FOR THIS PROPOSED CHANGE TO BE CONSISTENT WITH THE REQUIREMENTS OF IEEE-1547?

A. Yes. The Company intends for the proposed changes to be consistent with the requirements of IEEE-1547, as they may be amended from time to time.

Q. WHAT IS THE JUSTIFICATION FOR THE COMPANY'S REQUEST TO REQUIRE EXISTING CUSTOMER GENERATORS TO INSTALL A LOCAL INTERFACE FOR COMMUNICATION AND CONTROL?

A. Utility visibility and control of customer generation facilities becomes an essential function as the adoption of DER increases. 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. Both visibility and control are necessary functions to 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, gaps will be present in the Company's ability to be fully aware of the interaction of those facilities with other generation facilities and the rest of the electric grid.

Revenue Requirement Impacts

Q. WITH RESPECT TO THE RECOMMENDED CAPITAL REDUCTIONS FOR THE GRID INVESTMENT PROGRAM, DID PIA STAFF CORRECTLY CALCULATE ITS REVENUE REQUIREMENT IMPACT?

A. No. PIA Staff assumed the projected capital expenditures for the Grid Investment Program will close to plant-in-service as they are incurred, thus incorrectly

assuming the capital expenditures are the same as closures in its calculation of the revenue requirement impact. Since the capital expenditures are projected to close to plant in service later than when they are incurred in the Company's filing, assuming closures are the same as capital expenditures artificially inflates the reduction of average plant in service balances based on their recommendation. This results in a significantly overstated revenue requirement reduction for the test year and years 2023 through 2025. In addition, PIA Staff did not consider the impact of removing the related accumulated deferred income taxes (ADITs) in their proposed Grid Investment Program capital reduction, which also caused the revenue requirement reduction to be overstated.

IX. RECENT TAX LEGISLATION

Q. IS THE COMPANY ACTIVELY ANALYZING AND PURSUING THE BENEFITS PROVIDED IN THE RECENTLY PASSED INFLATION REDUCTION ACT ("IRA") AND INFRASTRUCTURE AND INVESTMENT JOBS ACT ("IIJA") LEGISLATION, AND DOES THE COMPANY PLAN TO PASS THOSE BENEFITS ON TO CUSTOMERS?

A. Yes. The Company is in the process of assessing the various potential impacts of the IRA and IIJA. The Company expects the IRA and IIJA will benefit customers through reduced project costs and lower income taxes. The Company has already identified several benefits from the IRA, with the details of those benefits provided in response to data request STF-LA-5-14. The Company continues to seek out additional opportunities under the new legislation that will benefit customers; however, there are many components of the IRA and IIJA that will take time to evaluate, and significant guidance from the IRS and Treasury will be necessary to administer the tax law changes in both Acts. The Company fully intends to pass any tax benefits related to the IRA and the IIJA on to customers.

Q. BASED ON THE COMPANY'S INITIAL ANALYSIS OF THE IRA, WHAT OPPORTUNITIES FOR TAX CREDITS WERE IDENTIFIED?

A. The Company's initial analysis of the IRA identified approximately $44 million of additional tax credit benefits related to projected, qualified renewable energy and electric vehicle investments. The largest benefit identified in the Company's initial analysis relates to investment tax credits ("ITC") associated with the Mossy Branch battery storage project. The Mossy Branch project, which is projected to go into service in 2023, is a project that the Company currently believes would qualify for a 30% ITC. Additionally, with the Commission's approval, the Company can opt-out of the traditional ITC normalization structure which would result in giving customers all the ITC benefit in the year the project goes into service instead of over the life of the asset. The Company also expects to generate ITCs on the McGrau Ford battery facility; however, those credits are not expected to be generated until after 2025 when the facility is expected to be placed into service. In addition, the Company's initial analysis shows the IRA will provide more options to pursue and compete for lower cost solar energy investments as a result of expanded tax credits. Through the IRA, the Company now has an option to choose between either the traditional ITC or a new Production Tax Credit ("PTC") for Company-owned solar projects; however, the Company is still not able to claim ITC or PTCs on solar resources procured through purchased power agreements, which account for the majority of the Company's new solar resources expected to come online in years 2023 through 2025. For new Company-owned solar facilities projected to come online in those years, the Company estimates the PTC option will provide approximately $0.4 million of additional benefits for customers in 2025 related to projected ash pond solar investments at Plant McIntosh, Plant McDonough, and Plant Hammond.

Since the filing of direct testimony, the Company identified IRA benefits for which it may qualify. Georgia Power estimates that the Hydro Modernization projects

approved by the Commission in the 2019 and 2022 IRP is currently estimated to provide approximately $3 million of tax benefits for the three years 2023 through 2025. The Company also anticipates qualifying for credits on the Integrated Hydrogen Microgrid project that was approved by the Commission in the 2022 IRP.

Q. HAS THE COMPANY PERFORMED AN INITIAL ANALYSIS OF QUALIFICATIONS FOR PTCs ON EXISTING NUCLEAR FACILITIES AVAILABLE THROUGH THE IRA?

A. The Company has performed initial analysis on the zero-emission nuclear production tax credits on existing nuclear facilities currently in service. Based on current guidelines in the IRA, it does not appear the Company will be eligible for the zero emission PTCs on the Company's nuclear facilities currently in operation; however, the Company is hopeful additional guidance from the Treasury will be issued on the gross receipts calculation used to calculate the credits that may allow the Company to qualify for these credits for the benefit of customers.

Q. HOW DOES THE COMPANY PROPOSE TO COMMUNICATE RESULTS OF THE IRA AND IIJA ANALYSIS TO THE COMMISSION?

A. The Company proposes to use existing mechanisms for data communication and discovery for this and future rate proceedings to provide tax and other savings resulting from the IRA and IIJA, noting that there should be benefits associated with the IRA and IIJA well beyond the period of this three-year ARP. The Company can agree to record these tax benefits to a regulatory liability for future consideration by this Commission to be used for the benefit of customers as soon as possible.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

REBUTTAL TESTIMONY OF

JAMES M. COYNE

ON BEHALF OF

GEORGIA POWER COMPANY

DOCKET NO. 44280

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is James M. Coyne, and I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Senior Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony to the Georgia Public Service Commission (the "Commission") on behalf of Georgia Power Company ("Georgia Power" or the "Company") on June 24, 2022.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the direct testimonies of the following witnesses as they relate to the appropriate return on equity ("ROE") and capital structure for Georgia Power: Mr. Michael P. Gorman on behalf of the Commission's Public Interest Advocacy Staff ("Staff"), Ms. Billie S. LaConte on behalf of Georgia Association of Manufacturers ("GAM"), Mr. Mark E. Ellis on behalf of Georgia Interfaith Power & Light ("GIPL"), Ms. Maureen L. Reno on behalf of the U.S. Department of Defense and Federal Executive Agencies ("DOD"), and Mr. Steve W. Chriss on behalf of the Commercial Group. I collectively refer to these individual witnesses as "Intervenor Witnesses."

Q. ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR REBUTTAL TESTIMONY?

A. No.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. My rebuttal testimony is organized to respond to the Intervenor Witnesses by issue, starting in Section II with an overview and summary of the results and recommendations presented by the various ROE witnesses in this proceeding. Section III discusses economic and capital market conditions and how those conditions are affecting the various models used to estimate the cost of equity for Georgia Power. In Section IV, I address the proper application of the cost of equity analytical models employed by me and the Intervenor Witnesses, including the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Bond Yield Plus Risk Premium ("Risk Premium") model and the Expected Earnings model. In Section V, I respond to comments raised by certain witnesses with respect to Georgia Power's proposed capital structure and cost of debt, and I explain why that capital structure is reasonable by comparison to the proxy group. In Section VI, I respond to comments regarding Georgia Power's company-specific risk factors raised by the Intervenor Witnesses. Lastly, in Section VII, I summarize my key conclusions and continue to recommend an 11.00 percent ROE (including flotation costs) and Georgia Power's actual capital structure of 56.0 percent common equity and 44.0 percent long-term debt.

II. SUMMARY OF TESTIMONY

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE ANALYSIS AND RECOMMENDATIONS PROVIDED BY THE INTERVENOR WITNESSES REGARDING THE APPROPRIATE ROE AND CAPITAL STRUCTURE FOR GEORGIA POWER?

A. My key conclusions are as follows:

(1) The Intervenor Witnesses' analyses contain flaws and inconsistencies that produce some results well below recent authorized returns for electric utilities, particularly those comparable to Georgia Power. Some recommendations are even 50 to 100 basis points below prevailing costs of debt for utilities. Such recommendations should be given no weight as no investor would take on the perpetual risks of equity ownership when they could earn a higher return for safer debt investments that have a senior claim on cash flows.

(2) The cost of equity for regulated utility companies is being affected by several key factors in the current and prospective capital markets, including the interest rate environment and central bank monetary policy, as well as current inflationary pressure. Inflation has escalated to levels not seen since the early 1980s; interest rates across the yield spectrum have increased; and capital market volatility remains elevated. These circumstances reinforce the importance of considering the results of multiple models, as I have with the DCF, CAPM, Risk Premium, and Expected Earnings approaches.

(3) All models are subject to certain limiting assumptions. However, in market conditions where ROE estimation models are producing return estimates below the current cost of debt for utilities (e.g., Mr. Ellis' DCF and CAPM estimates), utility regulators recognize that such low returns are not compensatory for investors. Rather than endorsing the results of a specific methodology, the Commission should consider how current market conditions affect the risks for equity investors as well as take into account the results of a broader range of ROE estimation methodologies.

Q. PLEASE SUMMARIZE THE COST OF CAPITAL RECOMMENDATIONS PRESENTED BY THE INTERVENOR WITNESSES IN THIS PROCEEDING?

A. The Intervenor Witnesses who performed an independent ROE analysis (Mr. Gorman, Ms. Reno, and Mr. Ellis) recommend an authorized ROE for Georgia Power between 5.54 percent and 9.47 percent. Other Witnesses did not perform their own ROE analysis, and instead adjusted certain inputs in my analyses (Ms. LaConte) or referenced authorized

returns for electric utilities in other jurisdictions (Mr. Chriss). Based on adjustments to my analyses using her preferred inputs, Ms. LaConte asserts that Georgia Power's cost of equity does not exceed 9.83 percent.[1]

As it relates to capital structure, Ms. Reno accepts the Company's capital structure recommendation.[2] Mr. Gorman accepts the Company's proposed 56 percent equity ratio for 2023, but recommends the Commission impute a hypothetical capital structure of 51 percent equity for 2024 and 2025.[3] Ms. LaConte recommends a capital structure that contains no more than 53 percent common equity.[4] Lastly Mr. Ellis recommends a capital structure that contains 61.70 percent equity to offset his 5.54 percent ROE recommendation.

As is evident, there is a broad array of recommendations from multiple witnesses. Notably, recommendations as low as 5.54 percent are below any authorized return for any electric utility in the last 40 years[5] and are lower than current market indicators of utility and corporate debt costs. Some of the recommendations are supported by analytical approaches while others are more judgmental or based on decisions from other jurisdictions. I submit that the appropriate method for determining the cost of capital is through the application of rigorous analysis using financial models and current market data from reliable sources.

Q. PLEASE PROVIDE AN OVERVIEW OF THE INTERVENOR WITNESSES' ANALYTICAL RESULTS IN THIS PROCEEDING?

A. Figure 1 summarizes the results from the Intervenor Witnesses which form the basis of their recommendations.

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1 Direct Testimony of Billie S. LaConte, at 9.

2 Direct Testimony of Maureen S. Reno, at 6.

3 Direct Testimony of Michael P. Gorman, at 3.

4 Direct Testimony of Billie S. LaConte, at 3.

5 Source: S&P Capital IQ Pro, Regulatory Research Associates. 8.70 percent is the lowest authorized ROE for an electric utility since 1980, excluding cases for limited-issue riders, formula-based rate plans, and ROEs that include penalties.

Figure 1: ROE Ranges and Recommendations of the Intervenor Witnesses

	Staff Mr. Gorman[6]	**GAM Ms. LaConte**[7]	**GIPL Mr. Ellis**[8]	**DOD Ms. Reno**[9]
DCF Results	8.07% - 9.20%	9.09%	5.97%	8.15% - 9.47%
CAPM/ECAPM Results	9.88% - 10.93%	9.84% - 10.57%	5.41%	8.23% - 9.84%
Risk Premium Results	9.21% - 9.28%	9.46%	NA	NA
Expected / Comparable Earnings Results	NA	NA	NA	9.85% - 10.76%
Equity Ratio Recommendation	56% (2023); 51% (2024 - 2025)	≤ 53%	61.70%	56%
ROE Recommendation (Range)	**9.45% (9.00%- 9.90%)**	**≤ 9.83%**	**5.54%**	**9.47% (8.81% - 9.47%)**

There are a number of flaws and inconsistencies with the analyses conducted by the Intervenor Witnesses. I address each analytical approach and explain why their assumptions are unreasonable. At the outset, one must question analyses producing results that are more than 300 basis points below any return authorized for any electric utility in at least 40 years.

6 Direct Testimony of Michael P. Gorman, at 32-33, 47, 52 59, 60.

7 Direct Testimony of Billie S. LaConte, at 9.

8 Direct Testimony of Mark E. Ellis, at 6.

9 Direct Testimony of Maureen L. Reno, at 7, 49.

Q. PLEASE DESCRIBE THE LEGAL STANDARDS THAT MUST BE MET TO ESTABLISH THE AUTHORIZED ROE FOR A REGULATED PUBLIC UTILITY SUCH AS GEORGIA POWER.

A. As discussed in my direct testimony, the standards for a just and reasonable return established by the United States Supreme Court in the *Hope* and *Bluefield* cases are:

(1) Financial integrity: the return must be adequate to ensure the company's financial soundness and support credit quality;

(2) Capital attraction: the return must be sufficient to enable the company to attract capital on reasonable terms and conditions; and

(3) Comparable return: the return must be comparable to those available to investors in firms with commensurate risk.

Importantly, in *Bluefield*, the U.S. Supreme Court recognized that a return may be reasonable at one time, but may become too high or too low at another time due to changes affecting investment opportunities, and market or business conditions.[10] This principle is relevant because, as discussed below, certain of the Intervenor Witnesses refer to recent authorized ROEs to support their recommendations, but do not fully consider the magnitude of the change in market conditions since those ROEs were determined.

Q. SEVERAL OF THE INTERVENOR WITNESSES (GORMAN, LACONTE, RENO, CHRISS) REFERENCE AUTHORIZED ROES FOR ELECTRIC UTILITIES IN OTHER JURISDICTIONS. DO YOU AGREE THAT THESE RETURNS ARE RELEVANT IN ESTABLISHING THE ROE FOR GEORGIA POWER IN THIS PROCEEDING?

A. National average returns must be placed in the proper context in order to be useful. While I agree that investors consider authorized returns in other states in assessing the

10 *Bluefield Water Works v. Public Service Commission*, 262 U.S. 679, 692 (1923).

reasonableness of the authorized ROE for Georgia Power, I have several concerns with the nationwide average ROE information presented by the Intervenor Witnesses. First, the averages referenced by Mr. Gorman and Mr. Chriss include ROE determinations for transmission and distribution-only ("T&D") electric utilities, as well as determinations in formula rate proceedings in which the ROE is determined by a formula solely tied to changes in Treasury bond yields. These ROE determinations are not comparable to authorized ROEs for vertically integrated electric utilities, nor are they comparable to determinations that are based on the use of various financial models as is the process used by the Commission. Vertically integrated electric utilities have a higher level of business risk than T&D utility companies that do not own regulated generation.[11] This higher risk profile differentiates integrated electric utilities from T&D utilities and supports a higher authorized ROE and equity ratio in the capital structure. Lastly, their references to average authorized ROEs do not include approvals earlier this year by the Florida Public Service Commission to increase the authorized ROEs of Florida Power & Light, Tampa Electric Company, and Duke Energy Florida due to increases in the 30-year Treasury yield outlined as part of those utilities' most recent rate case settlements.

Second, market conditions at the time the authorized returns were established are very different than conditions today and going forward. For example, equity returns set when interest rates were very low in 2020 are not a reasonable basis of comparison for an appropriate ROE in 2023 when bond yields have increased and are projected to continue increasing as the economy recovers and the Federal Reserve moves to a more neutral monetary policy. After the decline in interest rates in 2020-2021 driven by the Federal Reserve's unprecedented actions to respond to the COVID-19 pandemic, interest rates have increased by approximately 160 to 230 basis points since the settlement adopting an ROE of 10.50 percent for Georgia Power was authorized in December 2019.[12] Since my direct

11 Moody's Investors Service, Rating Methodology for Electric and Gas Utilities, June 23, 2017, at 21.

12 The 30-day average 30-year Treasury bond yield was 2.28 percent as of December 17, 2019. The current 30-day average on the 30-year Treasury bond yield is 3.92 percent as of October 31, 2022. The 30-day average A-rated Utility bond yield was 3.41 percent as of December 17, 2019, compared to 5.75 percent for the 30-day average as of October 31, 2022. The 30-day average Baa-rated Utility bond yield was 3.74 percent as of December 17, 2019, compared to 6.06 percent for the 30-day average as of October 31, 2022.

testimony was prepared in April 2022, the 30-day average 30-year Treasury yield has increased by more than 100 basis points and currently exceeds even the projections of the 30-year Treasury yield at the time I prepared my direct testimony. Although state utility commissions mitigated ROE reductions in 2020-2021 due to the knowledge that interest rates were being artificially suppressed due to the Federal Reserve's actions,[13] the use of prior decisions during that time period which set ROEs under previously lower interest rates understates the forward-looking cost of equity and the very different rising interest rate environment that we are now experiencing.[14] In other words, authorized ROEs that may have been considered reasonable and appropriate in 2020 and 2021, and even into the first half of 2022, are not reasonable in the current market environment, consistent with *Bluefield*.

Q. DOES THE ANNUAL AVERAGE AUTHORIZED ROE APPROPRIATELY REFLECT GEORGIA'S MORE CONSTRUCTIVE REGULATORY ENVIRONMENT?

A. No. Figure 2 below presents the annual average authorized ROEs for vertically integrated electric utilities by Regulatory Research Associates' ("RRA") ranking of the regulatory environment (Above Average, Average, and Below Average). As Figure 2 demonstrates, authorized ROEs by regulatory commissions ranked as "Above Average" are approximately 40 to 60 basis points above the average authorized ROE in "Average" jurisdictions.

13 S&P, The Big Picture: 2022 Electric, Natural Gas and Water Utilities Outlook (Oct 2021) ("S&P Oct. 2021") at 5 (finding that the spread between authorized ROE and interest rates increased because state utility commissions "recognized that long-term bond yields have been artificially suppressed due to the Fed[eral] Reserve's unprecedent intervention in the capital markets."; *see also* RRA, Major Energy Rate Case Decisions in the US—January-June 2022 (July 27, 2022) ("RRA July 22, 2022"). at 6 ("the gap between authorized ROEs and interest rates widened somewhat over this period, largely as a result of regulators' often-unstated understanding that the decline in interest rates caused by Federal Reserve intervention was unusual.").

14 RRA July 29, 2022, at 7 (with interest rates on the rise "the average authorized returns for full year 2022 and 2023 may edge higher"); *accord id.* at 4 ("Authorized returns may edge slightly higher going forward as the U.S. Federal Reserve continues efforts to tamp down soaring inflation via a series of interest rate hikes, the first of which was announced in March").

Figure 2: Annual Average Authorized ROE by Commission Ranking for Vertically Integrated Electric Utilities[15]

	Above Average	Average	Below Average
2019	10.06%	9.60%	9.70%
2020	9.89%	9.47%	9.45%
2021	10.01%	9.40%	8.85%
2022	10.15%	9.62%	9.35%

ROE recommendations that are more consistent with those authorized by "Below Average" or "Average" jurisdictions would undermine investors' perceptions of Georgia's supportive and constructive regulatory climate, ultimately increasing the Company's regulatory risk.

Q. DOES CURRENT MARKET DATA ILLUSTRATE THE UNREASONABLENESS OF MR. ELLIS'S ROE RECOMMENDATION?

A. Yes. Current utility bond yields measured by Moody's utility bond indices are approximately 50 to 80 basis points *above* Mr. Ellis's ROE recommendation.[16] It is simply illogical to expect that a rational investor would take on the risk of a utility equity investment when they could earn a higher return from a safer bond that has a senior claim on cash flow. Mr. Ellis attempts to adjust current utility bond yields below his cost of equity estimates to account for certain risk premia (e.g., liquidity risk) and concludes without any evidence that an equity premium between 67 and 124 basis points would be a sufficient premium for equity investors.[17] There is no evidence to demonstrate that equity investors would be willing to accept such a small premium for taking on the risk of utility equity investment.

15 Source: Regulatory Research Associates. Vertically integrated electric rate cases completed through November 3, 2022. Includes the ROE "trigger" settlement provisions approved by the Florida Public Service Commission in 2022 for Florida Power & Light (10.80% ROE), Duke Energy Florida (10.10% ROE), and Tampa Electric Company (10.20% ROE).

16 Source: Federal Reserve Bank of St. Louis FRED Economic Database, as of October 31, 2022.

17 Direct Testimony of Mark E. Ellis, at 74.

Mr. Ellis's 5.54 percent ROE recommendation is substantially below national average authorized ROEs for vertically integrated electric utilities. In fact, it is nearly 400 basis points below the 9.53 percent average authorized ROE for vertically integrated electric utilities in 2021 cited by Ms. LaConte and Ms. Reno. Mr. Ellis' higher equity ratio recommendation of 61.70 percent does not offset the unreasonableness of his ROE recommendation. The weighted cost of equity produced by Mr. Ellis's ROE and capital structure recommendation is 3.42 percent (i.e., 5.54 percent multiplied by 61.70 percent). If adopted, Mr. Ellis's weighted cost of equity would be well below that recently authorized for vertically integrated electric utilities. The average weighted cost of equity for vertically integrated electric utilities in 2022 is 5.06 percent,[18] 163 basis points above Mr. Ellis's recommended weighted cost of equity. In fact, the 2022 average authorized weighted cost of equity is only 39 basis points below his ROE recommendation, further demonstrating the unreasonableness of his recommendation. Mr. Ellis's recommendation is far too low to be reasonable and would not satisfy the *Hope* and *Bluefield* standards for a risk comparable return that would allow the Company to attract capital and maintain its financial integrity. Moreover, it would represent a substantial departure from Georgia's supportive regulatory environment, introducing significant regulatory risk and higher costs of both debt and equity to the detriment of customers.

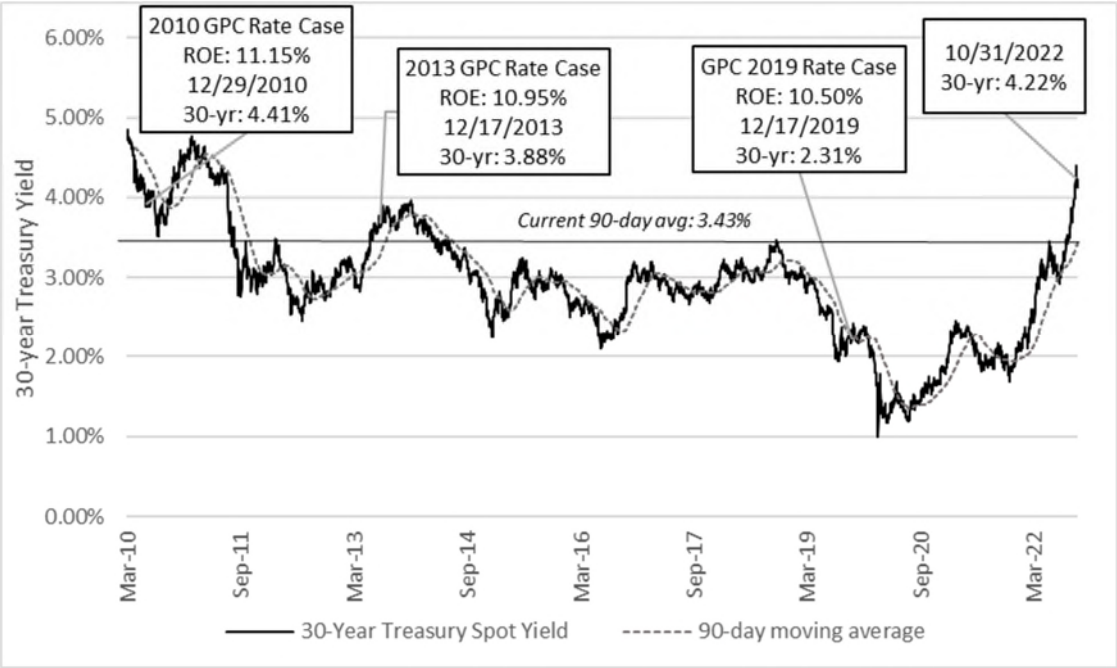
Q. HOW DOES THE CURRENT INTEREST RATE ENVIRONMENT COMPARE TO THE ENVIRONMENT DURING THE COMPANY'S PRIOR RATE CASES?

A. As shown in Figure 3 below, the interest rate environment is currently above the levels experienced during the Company's 2019 rate case and 2013 rate case. Specifically, the spot yield on the 30-year Treasury bond as of October 31, 2022 was 4.22 percent, 191 basis points above the spot yield at the time of the Commission's decision in the Company's 2019 rate case and 34 basis points above the yield at the time of the Commission's decision

18 Source: Regulatory Research Associations. Authorized ROE and equity ratios for vertically integrated electric utilities through November 3, 2022. Excludes limited rider rate proceedings and ROEs authorized in formula rate proceedings in which the ROE is adjusted based on changes in Treasury bond yields. Excludes decisions from jurisdictions that include non-investor supplied capital in the ratemaking capital structure.

in the 2013 rate case when the Commission approved a 10.95 percent ROE. The last time the 30-year Treasury yield was 4.22 percent was in July 2011. Even if we looked to the 90-day moving average, the current 90-day average 30-year Treasury yield of 3.43 percent is at its highest level since August 2014.

Figure 3: 30-Year Treasury Yield (2010-2022)[19]



The Intervenor Witnesses' recommendations to *reduce* the Company's authorized ROE runs counter to the current capital market environment of *increasing* capital costs that are at their highest levels in at least seven years. My 11.00 percent ROE recommendation, on the other hand, reflects less than 30 percent of the 191-basis point increase in the 30-year Treasury bond yield since December 2019 when the Commission authorized the Company's current 10.50 percent ROE.[20]

19 Source: Bloomberg Professional.

20 The difference between 10.50% and 11.00% is 0.50%. 0.50% / 1.91% = 26%.

III. CAPITAL MARKET CONDITIONS

Q. PLEASE SUMMARIZE THE ECONOMIC AND FINANCIAL MARKET CONDITIONS OVER THE PAST SEVERAL MONTHS SINCE YOU SUBMITTED YOUR DIRECT TESTIMONY?

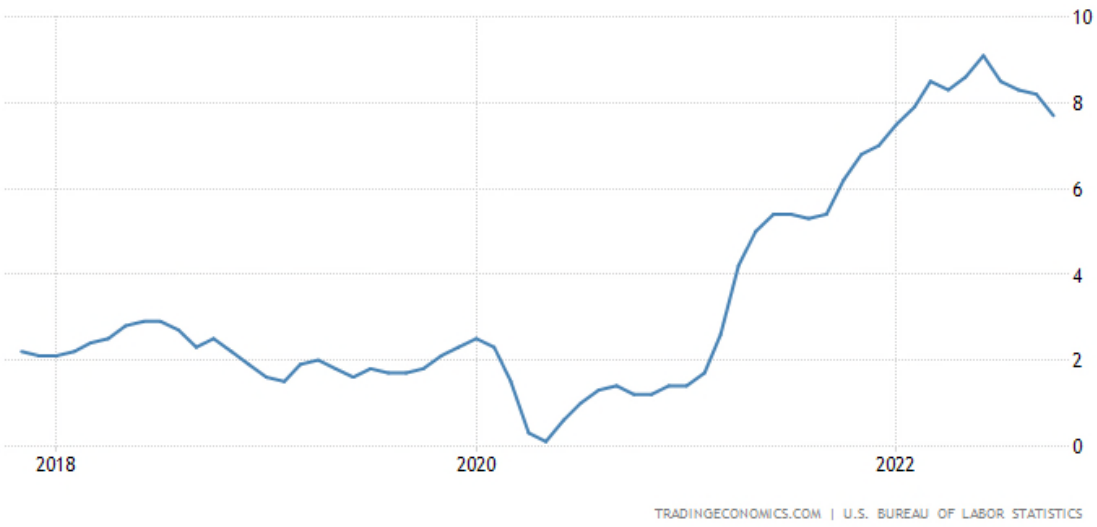
A. The conditions described in my direct testimony have continued since April 2022 and the primary capital market indicators continue to support higher return requirements by utility equity investors. Specifically, (1) inflation remains at levels not seen since the early 1980s, (2) interest rates across the yield spectrum have continued to increase, and (3) the elevated capital market volatility has sustained longer than anticipated.

It is important to consider current and expected conditions in the general economy and financial markets because the authorized ROE for a public utility should allow the utility to attract investor capital at a reasonable cost under a variety of economic and financial market conditions.

Q. PLEASE DISCUSS THESE CHANGES AND ROOT CAUSES OF THESE SHIFTS IN CAPITAL MARKET CONDITIONS.

A. Inflation has been both the greatest surprise and cause for concern among both policymakers and investors. As illustrated below, inflation levels have moved within a relatively narrow band over the past twenty years (other than during the Great Recession of 2007/2008). Starting with the initial stages of the COVID-19 pandemic in 2020, inflation levels have been driven higher, reaching a peak of 9.0 percent in June of 2022 and leveling off at 7.7 percent in October 2022. Inflation is being driven by strong consumer demand and supply constraints, some of which have been exacerbated by COVID-19 related government stimulus programs in the U.S. and international lockdowns. More recently, the war in Ukraine, which began in February, is constraining the world's supply of food and fuel, pushing overall inflation higher and feeding into the cost of other products and services.

Figure 4: Consumer Price Index – All Urban, Not Seasonally Adjusted[21]



As a result of these substantially higher inflation rates, the Federal Reserve has been left little choice but to pull back on its COVID-related monetary policies and battle inflation with its only effective tool: higher interest rates. In response to the economic effects of COVID-19, the Federal Reserve had decreased the federal funds rate in March 2020 to a target range of 0.00 percent to 0.25 percent (which remained in effect until March 2022) in addition to other stimulus measures which increased the supply of money in the economy. Since I prepared my ROE analysis provided in direct testimony (with market data through April 29, 2022), the Federal Reserve has continued unwinding its quantitative easing policy and increased the target rate six times, beginning with 25 basis points on March 17, 50 basis points on May 5, 75 basis points on June 16, another 75 basis points on July 27, another 75 basis points on September 21, and another 75 basis points on November 3 to a target range of 3.75 – 4.00 percent. Expectations are for further increases this year, with FOMC participants' median projection of 4.375 percent by the end of 2022, increasing to 4.60 percent by the end of 2023.[22] This demonstrates the level of Federal Reserve action necessary to reel in inflation. The Fed is willing to risk a slowdown in the economy, and it is clear that the era of record low interest rates and moderate inflation has closed. The 10-

21 Source: https://tradingeconomics.com/united-states/inflation-cpi (accessed November 11, 2022).

22 Federal Reserve Board of Governors Summary of Economic Projections, at 4 (September 21, 2022).

year bond, which closed out April 2022 at 2.89 percent, closed out October at 4.10 percent, and the 30-year yield, which closed out April at 2.96 percent, closed out October at 4.22 percent, both up substantially since I developed my direct testimony. Notably, the pace of the increase in Treasury bond yields escalated in September and October. For example, over the four months between the end of April and the end of August, the 10-year Treasury bond yield and 30-year Treasury bond yield increased by 26 and 31 basis points, respectively; however, over the most recent two months (end of August to end of October), the 10-year Treasury bond yield and 30-year Treasury bond yield both increased by 95 basis points, respectively.

Equity markets have also been affected. The Chicago Board Options Exchange ("CBOE") Volatility Index ("VIX") climbed higher, from an average of 24.3 in April to 30.0 in October.[23] For context, the VIX averaged 16.9 percent from 2010-2019, indicating increased levels of market volatility (and risk) for equity investors today. Because investors require higher returns to compensate them for greater risk, increased equity market volatility is indicative of higher return requirements for equities, including utilities.

Q. HAVE UTILITY STOCK PRICES ALSO BEEN MORE VOLATILE IN RECENT MONTHS?

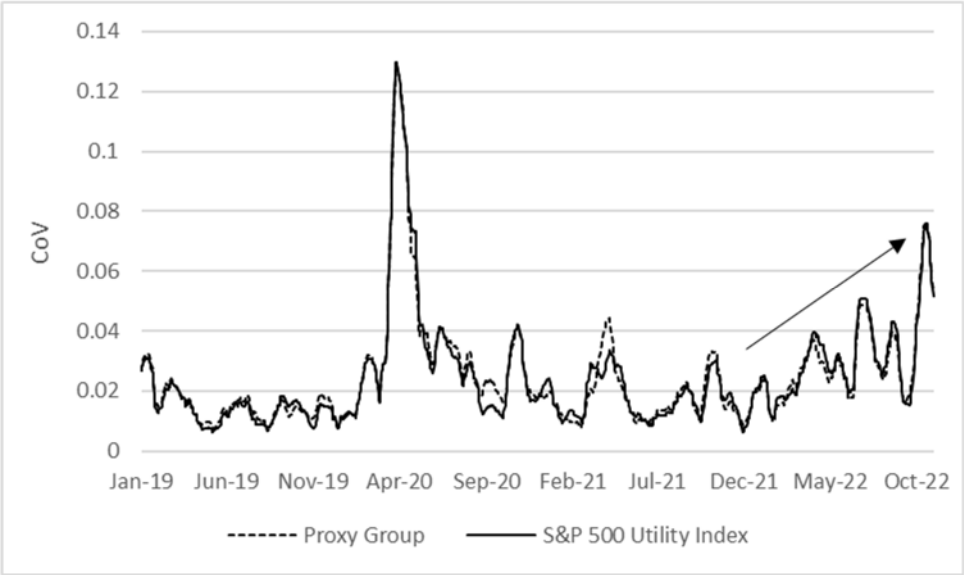
A. Yes, they have. The Coefficient of Variation is a measure of volatility defined as the ratio of the standard deviation to the mean over a given period. I calculated the Coefficient of Variation in the market price for the proxy group and the S&P 500 Utilities Index over a rolling 30-day period[24] to assess the trend in utilities' stock price volatility. As Figure 5 below shows, the Coefficient of Variation has been on an upward trend since the end of

23 Source: Federal Reserve Bank of St. Louis FRED Economic Database. The VIX Index is a calculation designed to produce a measure of constant, 30-day expected volatility of the U.S. stock market, derived from real-time, mid-quote prices of S&P 500® Index (SPX℠) call and put options. On a global basis, it is one of the most recognized measures of volatility -- widely reported by financial media and closely followed by a variety of market participants as a daily market indicator. Source: CBOE.com

24 A 30-day period is consistent with the VIX's measurement of expected volatility over the coming 30 days.

2021 and has reached the highest point level since the onset of the COVID-19 pandemic in March 2020.

Figure 5: Utility Stock Price Volatility (2019-2022)[25]



Q. MR. GORMAN ASSERTS THAT RISK PREMIUMS AS MEASURED BY CREDIT SPREADS ARE "REASONABLY ALIGNED WITH LONG-TERM HISTORICAL AVERAGES."[26] DO YOU AGREE WITH HIS INTERPRETATION?

A. No, I do not. In his Table 12 on page 51, Mr. Gorman reviews annual average spreads between utility and corporate A-rated and Baa-rated bond yields and the 30-year Treasury yield from 2019 to 2022 and compares those to the average historical spread. However, his annual averages obscure variation over each year. Notably, his 2022 average masks the widening in credit spreads that have occurred over the course of 2022, resulting in his misleading conclusion that current credit spreads are "reasonably aligned with long-term historical averages." As Figures 6 and 7 below show, utility credit spreads have widened considerably since January 2022 and are currently above both their 2022 annual average

25 Source: Bloomberg Professional.

26 Direct Testimony of Michael P. Gorman, at 51.

and long-term average. Widening credit spreads are an indication that investors are requiring higher premiums to invest in utility bonds over safer government bonds.

Figure 6: Credit Spread A-rated Utility – 30-Year Treasury Yield (Jan – Oct 2022)[27]



27 Source: Bloomberg Professional. Long-term historical average spread reflects 1993-2022; 2022 annual average updated through October 31, 2022.

Figure 7: Credit Spread Baa-rated Utility – 30-Year Treasury Yield (Jan – Oct 2022)[28]



Q. ARE CONDITIONS EXPECTED TO STABILIZE IN THE NEAR-TERM?

A. It does not appear so. While difficult to predict in the long-term, capital market conditions remain unsettled. The economy and capital markets remain in a tenuous state with ongoing global supply constraints and expectations of weaker consumer demand in the face of persistent inflation and higher interest rates. Interest rates may not fully reflect the effects of inflation because no one knows exactly how high interest rates must go before inflation returns to more acceptable levels. The Federal Reserve has been targeting inflation of around 2.0 percent for many years, as compared with current annualized inflation of 7.7 percent at the consumer level for the 12-month period ending in October 2022.

Looking forward, the inflation risks in the market are twofold: (1) either inflation becomes embedded in the economy if the Federal Reserve does not move aggressively enough in tightening monetary policy, or (2) the Federal Reserve responds to inflationary pressure by raising short-term interest rates to a level that causes a slowdown in economic growth or a

28 Source: Bloomberg Professional. Long-term historical average spread reflects 1993-2022; 2022 annual average updated through October 31, 2022.

recession. The November 2022 issue of Blue Chip Financial Forecasts ("Blue Chip") reports the results of a survey of leading economists and market analysts taken in October 2022. Blue Chip reports that 19 percent think that by removing monetary accommodation, the Federal Reserve will be successful in slowing inflation in the U.S. without causing a recession, while 81 percent believe that monetary tightening will precipitate a U.S. recession.[29]

Q. MR. GORMAN AND MS. RENO REFER TO RECENT UTILITY STOCK PERFORMANCE TO SUPPORT THEIR ROE RECOMMENDATIONS. HOW HAVE UTILITIES PERFORMED RELATIVE TO THE BROADER MARKET IN RECENT MONTHS?

A. Mr. Gorman argues that utilities' "robust valuations" are an indication that utilities can access equity capital at low cost.[30] Ms. Reno observes that utility stocks outperformed the overall stock market between January and August 2022.[31] While utility stocks caught up to the broad market in the first half of 2022, that changed quickly in September and October as utilities were one of the worst performing sectors of the S&P 500 in September and continued to underperform the market in October. As noted in my direct testimony, utilities often underperform the market in 12-month periods after top-decile monthly relative returns for the sector.[32] As shown in Figure 8 below (an update to Figure 5 from my direct testimony), the S&P Utilities Index and The Southern Company's stock price continue to lag behind the broader market compared to pre-pandemic levels.

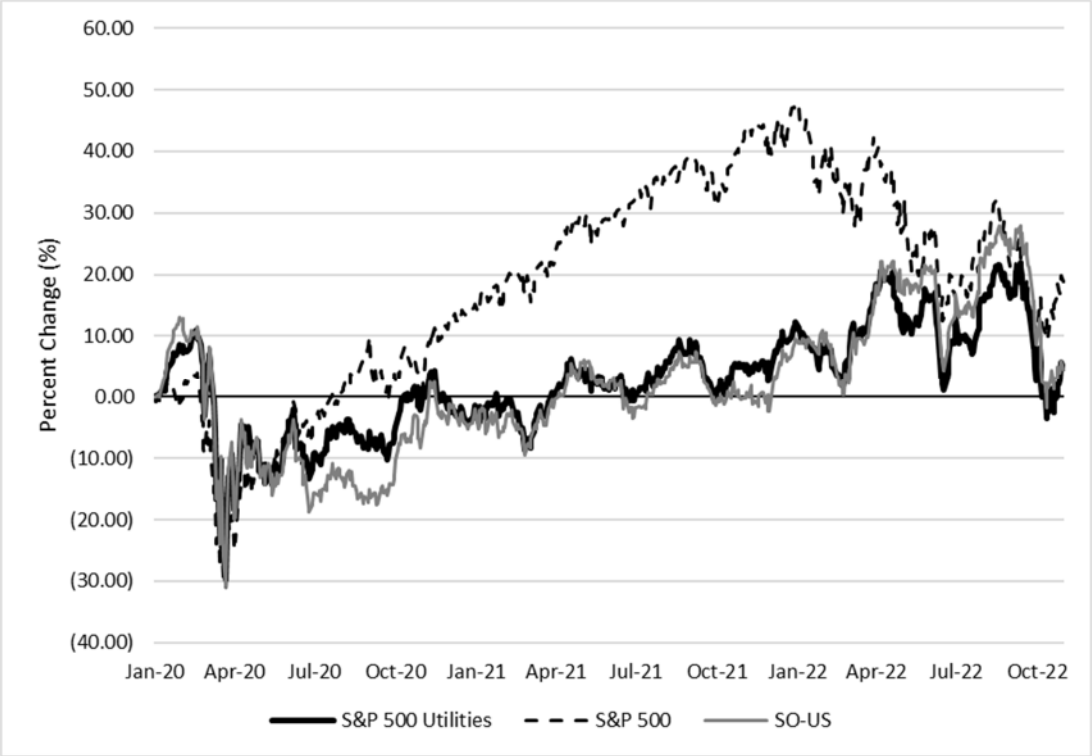
29 Blue Chip Financial Forecast, Vol. 41, Issue No. 11, November 1, 2022, at 14.

30 Direct Testimony of Michael P. Gorman, at 7-8.

31 Direct Testimony of Maureen L. Reno, at 14-15.

32 Direct Testimony of James M. Coyne, at 15-16.

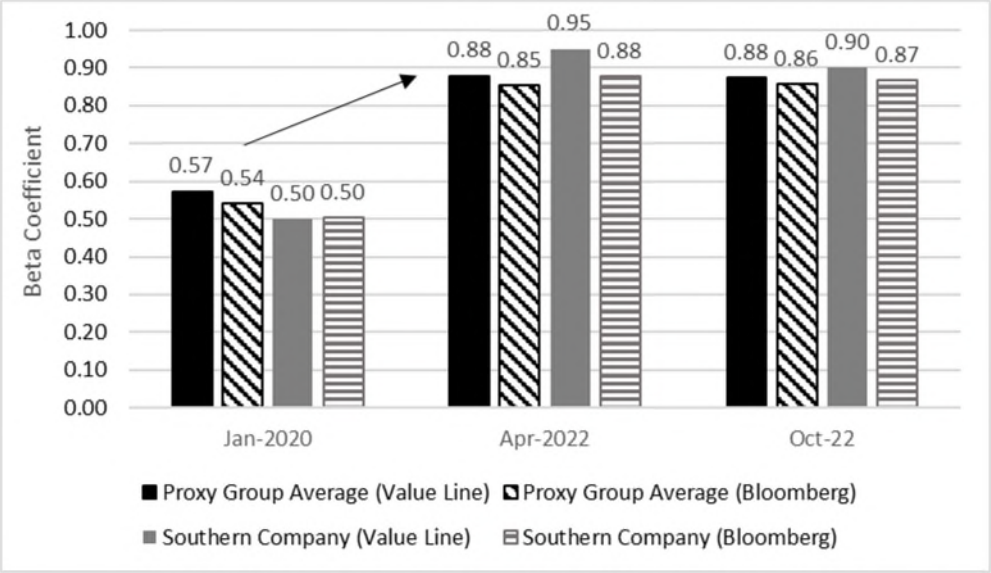
Figure 8: Relative Performance of Utilities and the S&P 500, January 2020 – October 2022[33]



As shown in Figure 9 below (an update to Figure 4 of my Direct Testimony), Beta coefficients for the proxy group and The Southern Company remain elevated.

33 Source: S&P Capital IQ.

Figure 9: Beta Coefficients for Proxy Group and The Southern Company[34]



Q. HAVE YOU FACTORED THESE CIRCUMSTANCES INTO YOUR ROE RECOMMENDATION FOR GEORGIA POWER AND, IF SO, WHAT CONCLUSIONS DO YOU DRAW?

A. Yes. Long-term interest rates have increased substantially since the historic lows of 2020 and are expected to continue to increase as the Federal Reserve unwinds its pandemic response measures and focuses on inflation. This supports the use of both current and forecast bond yields in the CAPM and Risk Premium models. These circumstances also reinforce the importance of considering the results of multiple models, as I have with the DCF, CAPM, Risk Premium, and Expected Earnings approaches. By contrast, several of the Intervenor Witnesses have focused on one or two models, leading to an unnecessarily narrow view, especially under current market conditions that impact the models differently. On balance, my updated review of the capital market environment continues to support my recommendation for an 11 percent ROE and 56 percent equity ratio and their consistency with the *Hope* and *Bluefield* standards.

34 Value Line and Bloomberg as of October 31, 2022.

IV. COST OF EQUITY ANALYSES

Q. DO THE INTERVENOR WITNESSES ACCEPT YOUR PROXY GROUP?

A. Yes, the Intervenor Witnesses generally accept my proxy group as being reasonable. However, Mr. Gorman excludes American Electric Power Company ("AEP"), due to the pending sale of its Kentucky electric utility, and includes The Southern Company. As explained in my direct testimony, I disagree with the inclusion of Georgia Power's parent company as it reflects circular logic.

Q. IS AEP'S PENDING SALE OF KENTUCKY POWER COMPANY A SIGNIFICANT TRANSACTION THAT WARRANTS AEP'S EXCLUSION FROM THE PROXY GROUP?

A. No, it is not. The primary reason to exclude companies on the basis of merger and acquisition activity is because significant transactions can affect the market data (e.g., stock prices) on which certain of the models rely. At the time the transaction was announced, AEP had a market capitalization of $42.23 billion; the Kentucky Power transaction is valued at $2.646 billion or only approximately 6.3 percent of AEP's total market value at the time the transaction was announced. Consequently, the transaction is not significant enough to warrant AEP's exclusion from the proxy group.

A. DCF MODEL

Q. MS. RENO BASES HER ROE RECOMMENDATIONS ON THE RESULTS OF HER DCF ANALYSIS, WHILE MR. GORMAN AND MR. ELLIS GIVE 50 PERCENT WEIGHT TO THEIR DCF MODEL ESTIMATES IN DETERMINING THEIR ULTIMATE ROE RECOMMENDATIONS. DO YOU AGREE THAT IT IS APPROPRIATE TO PLACE THIS DEGREE OF RELIANCE ON THE DCF MODEL FOR A U.S. UTILITY?

A. No, I do not. As discussed in my direct testimony, while many U.S. utility regulators have used the DCF model to establish the authorized ROE, several regulators, including FERC,

have recognized the challenges associated with relying solely on the DCF to establish the authorized ROE for regulated utilities in recent years.[35] For that reason, other federal and state regulators have relied on the results of multiple methodologies both to test the reasonableness of the DCF results and to establish a cost of equity that reflects investors' required return on a going-forward basis.

Q. PLEASE ELABORATE ON YOUR CONCERNS WITH THE DCF MODEL UNDER CURRENT MARKET CONDITIONS.

A. Although I have included the DCF model in my analyses, I have concerns with the ability of the DCF model to produce reliable results under current market conditions. This concern is amplified with an ROE analysis or recommendation relying exclusively on the DCF model. As explained in my direct testimony, high utility valuations are expected to decline as utilities underperform the broader market and, under these circumstances, the results of the DCF model would understate the forward-looking cost of equity because the dividend yield is calculated using historical average stock prices which do not fully reflect these expectations.[36] This shift has already begun to occur.

Mr. Gorman observes the high valuations of electric utilities, referencing the higher than average P/E ratios. However, he disregards the effect of those high valuations on the results of the DCF model, in particular the dividend yield component. Exhibit__(MPG-3) page 4 demonstrates the decline in the Value Line electric utility dividend yields over the past decade, from 4.20 percent in 2012 to 3.36 percent in 2022. This indicates that investors are paying more for a dollar of earnings from electric utilities than they did 10 years ago. As interest rates increase from historic lows, these high valuations are likely to come under pressure and decline. As noted earlier, utility stocks have underperformed the broad market in September and October after outperforming earlier in 2022. As a result, my conclusion is that the DCF model is understating the forward-looking cost of equity for regulated

35 Direct Testimony of James M. Coyne, at 28-29.

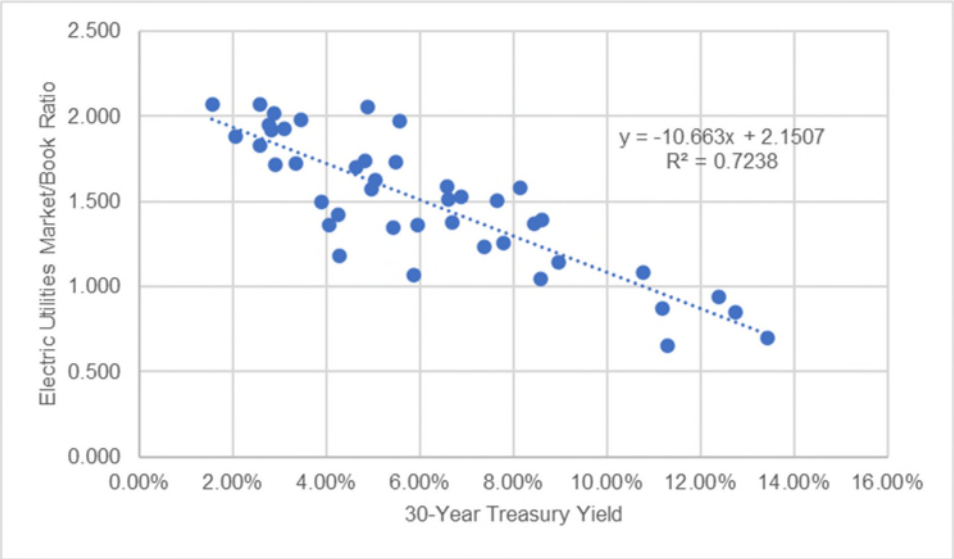
36 Direct Testimony of James M. Coyne, at 15-16.

utilities such as Georgia Power because the model is based on average historical stock prices that are based on unsustainable valuation levels.

Mr. Ellis[37] regards high market-to-book ("M/B") ratios as a sign that authorized ROEs for regulated utilities are higher than the investor required cost of equity. To test this premise, I performed an analysis that examines the correlation between government bond yields and the market-to-book ratios for electric utilities since 1980, using data provided in Exhibit__(MPG-15) and Exhibit__(MPG-18) to Mr. Gorman's direct testimony. As shown in Figure 10, the R^2 for this analysis is approximately 0.72, indicating a strong linear relationship between M/B ratios and interest rates. This relationship indicates that utility M/B ratios have increased not because authorized returns were higher than the true cost of equity, but because interest rates on government bonds have steadily declined for the past four decades. Low interest rates are favorable for capital-intensive industries such as utilities, while increasing interest rates are not.

37 Direct Testimony of Mark E. Ellis, at 14-18.

Figure 10: Market-to-Book Ratios and Interest Rates



1. Growth Rates in the DCF Model

Q. PLEASE COMMENT ON THE INTERVENOR WITNESSES' USE OF GROWTH RATES IN THE DCF MODEL.

A. Mr. Gorman and Ms. Reno consider a variety of growth rates including projected earnings per share ("EPS"), dividends per share ("DPS"), and book value per share, as well as "sustainable" growth rates and projected GDP growth. As explained in my direct testimony, over the long term, dividend growth can only be sustained by earnings growth,[38] while dividend growth can depend on management decisions regarding the dividend payout ratio over the near-term which do not reflect the long-term growth prospects of the company.

I agree, however, with Mr. Gorman's and Ms. Reno's decision to essentially discard the results of their Constant Growth DCF analysis that apply sustainable growth rates. I note that their sustainable growth rate calculations rely on Value Line's projected ROE data for the proxy group companies. Those projected ROEs are substantially higher than the results

38 Direct Testimony of James M. Coyne, at 26-27.

of the DCF model using sustainable growth rates presented by any of the Intervenor Witnesses, and demonstrate the fact that investors are expecting to earn higher returns on equity from the proxy group companies than what is shown by the DCF model using "sustainable growth rates" calculated from the same source, Value Line. This is an inherent inconsistency in their sustainable growth approach to the DCF.

Q. MR. ELLIS EXPRESSES CONCERNS THAT ANALYSTS' PROJECTED EPS GROWTH RATES ARE "OPTIMISTIC,"[39] WHILE MR. GORMAN CLAIMS THAT LONG-TERM GDP GROWTH SERVES AS A CAP ON LONG-TERM EPS GROWTH RATES AND SUGGESTS THAT SHORT-TERM EPS GROWTH RATES ARE TOO HIGH.[40] DO YOU SHARE THOSE CONCERNS ABOUT ANALYSTS' PROJECTED EPS GROWTH RATES?

A. No, this is a familiar refrain, but unsubstantiated for utilities. The 2003 Global Analysts Research Settlement (the "Global Settlement") served to significantly reduce the bias referred to by Mr. Ellis. In fact, the Global Settlement required financial institutions to insulate investment banking business from the analysis business, prohibited analysts from participating in "road shows," and required the settling financial institutions to fund independent third-party research.

A 2010 article in Financial Analysts Journal found that analyst forecast bias declined significantly or disappeared entirely after the Global Settlement:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced.

39 Direct Testimony of Mark E. Ellis, at 36-37.

40 Direct Testimony of Michael P. Gorman, at 43-44.

> These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[41]

In addition, analysts covering the common stock of the proxy companies certify that their analyses and recommendations are not related, either directly or indirectly, to their compensation. Thus, it is unclear why investors would assume that the proxy companies are susceptible to a continuing upward bias in earnings projections, especially given the fact that electric utilities operate in the mature stage of a stable industry with a very high degree of financial transparency due to their regulation. Further, to the extent Mr. Ellis believes that investors are well aware of these optimistic or biased growth rates, that suggests that utility stock prices already reflect that information.

Likewise, actual earnings data belie Mr. Gorman's position that projected GDP growth represents a cap on long-term EPS growth. The suggestion that equity earnings are limited by future growth in GDP may hold for aggregate corporate earnings in a closed economy but these are not realistic assumptions for an individual firm nor for utilities in general.[42] To illustrate this point, I have compared the actual historical EPS and dividend per share ("DPS") growth rates (to the extent data was available through Value Line) of all U.S. electric utilities and the companies in my proxy group from 2011-2021 to historical and projected GDP growth rates from Blue Chip, the Energy Information Administration, and the Social Security Administration. The results are shown in Figure 11 below.

41 Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010 at 195.

42 See MSCI Barra Research Bulletin, Is There a Link Between GDP Growth and Equity Returns? (May 2010).

Figure 11: Analysis of EPS, DPS, and GDP Growth Rates[43]

		[1] Historical 2011 - 2021		[2] Historical 2011 - 2021	[3] Projected	% Historical Difference		% Historical Multiple	
	No. of Companies	EPS Growth	DPS Growth	GDP Growth	GDP Growth	EPS vs GDP	DPS vs GDP	EPS vs GDP	DPS vs GDP
U.S. All Electric Companies [4]	36	4.37%	5.57%	4.15%	4.24%	0.23%	1.42%	1.1	1.3
GPC Proxy Group	14	5.08%	6.13%	4.15%	4.24%	0.93%	1.98%	1.2	1.5
AVERAGE		4.73%	5.85%	4.15%	4.24%	0.58%	1.70%	1.1	1.4

As shown in Figure 11, the EPS and DPS growth rates of utilities can, and do, exceed GDP growth for sustained periods. Specifically, for the Georgia Power proxy group, historical EPS has exceeded historical GDP growth by 0.93 percent from 2011-2021 and historical DPS has exceeded historical GDP growth by 1.98 percent over the same period. This rate of growth is 10 to 40 percent greater than GDP over this same period. My conclusion is that it is not unreasonable to rely on analyst EPS growth projections, as I and other experts commonly do, just because they exceed GDP growth.

I do not share Mr. Ellis' and Mr. Gorman's concern that analysts' projected EPS growth rates are too high. Mr. Gorman ultimately relies on analysts' projected EPS growth rates in his Constant Growth DCF model, which forms the lower boundary of his recommended ROE range, effectively discarding the results of his Multi-Stage DCF model results that include projected GDP growth in the terminal stage. The average EPS growth rate that Mr. Gorman uses in his Constant Growth DCF model (5.45 percent) is consistent with the average EPS growth rates used in my Constant Growth DCF analysis (5.61 percent) and is more reasonable. His over-reliance on this result, however, unduly forces his overall ROE recommendation downward.

43 Sources: Value Line, Blue Chip Financial Forecasts, Bureau of Economic Analysis, US Energy Information Administration,

Q. PLEASE DESCRIBE THE ISSUE WITH THE APPLICATION OF SUSTAINABLE GROWTH OR RETENTION GROWTH IN THE CONSTANT GROWTH DCF MODEL.

A. The sustainable growth rate or retention growth rate calculation assumes that future earnings will increase as the retention ratio increases. However, this relationship may not hold for a given company based on management decisions associated with the dividend payout rate. This conclusion is supported by two articles published in the *Financial Analysts Journal* that discussed the theory that high dividend payouts (*i.e.*, low retention ratios) are associated with low future earnings growth.[44] Each of those articles cited to a 2003 study by Arnott and Asness[45] that found, over the course of 130 years of data, future earnings growth is associated with high, rather than low payout ratios.[46] Specifically, Arnott and Asness concluded:

> Unlike optimistic new-paradigm advocates, we found that low payout ratios (high retention rates) historically precede low earnings growth. This relationship is statistically strong and robust. We found that the empirical facts conform to a world in which managers possess private information that causes them to pay out a large share of earnings when they are optimistic that dividend cuts will not be necessary and to pay out a small share when they are pessimistic, perhaps so that they can be confident of maintaining the dividend payouts. Alternatively, the facts also fit a world in which low payout ratios lead to, or come with, inefficient empire building and the funding of less than-ideal projects and investments, leading to poor subsequent growth, whereas high payout ratios lead to more carefully chosen projects. The empire-building story also fits the initial macroeconomic evidence quite well. At this point, these explanations are conjectures; more work on discriminating among competing stories is appropriate.[47]

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44 Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. *See* also Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 1, 2006.

45 Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

46 Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

47 Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

Given that all three studies found that there is a negative relationship between earnings growth and retention ratios, the application of retention growth rates in the DCF model is not appropriate.

2. Multi-Stage DCF Approach

Q. MR. GORMAN AND MR. ELLIS HAVE ALSO PRESENTED THE RESULTS OF A MULTI-STAGE DCF MODEL.[48] DO YOU AGREE THAT THE RESULTS AND WEIGHT PLACED ON THOSE ANALYSES ARE REASONABLE?

A. No, I do not. Mr. Gorman presents the results of a Multi-Stage DCF analysis but elects not to rely on those results in setting his range or recommendation for Georgia Power, presumably because he views the results as being too low.[49] Mr. Ellis also performs a Multi-Stage DCF model, but unlike Mr. Gorman, he relies on those results for his ROE recommendation, even though his Multi-Stage DCF result of 5.97 percent is more than 450 basis points below Georgia Power's current authorized ROE and significantly below any ROE authorized for any electric utility in at least the last 40 years.

Mr. Ellis's use of an inflation rate as a proxy for earnings growth has no reasonable basis of support, as he has provided no evidence that investors would accept growth in perpetuity that tracks inflation. There are many investment alternatives available that offer more attractive growth and return potential. As noted earlier, utility bond yields are currently offering returns comparable to or higher than Mr. Ellis's DCF-based cost of equity recommendation. No investor would commit capital to an equity investment if they can receive an equal or higher return from a safer debt investment that has a senior claim on cash flow.

48 See, for example, Direct Testimony of Michael P. Gorman, at 41-47, Direct Testimony of Mark E. Ellis, at 46-50.

49 Direct Testimony of Michael P. Gorman, at 47.

B. CAPM ANALYSIS

Q. BEFORE RESPONDING TO THE INTERVENOR WITNESSES' CRITICISMS OF YOUR CAPM ANALYSIS, ARE THERE AREAS OF AGREEMENT WITH RESPECT TO YOUR RESPECTIVE CAPM ANALYSES?

A. Yes, there are. First, Mr. Gorman, Ms. LaConte, Ms. Reno, and Mr. Ellis, and I agree that the 30-year Treasury bond yield is appropriate to use as the risk-free rate.[50] Second, although certain of the Intervenor Witnesses disagree with the use of projected interest rates, Mr. Gorman includes a projection of the 30-year Treasury in his analysis, suggesting he believes that the current rate underestimates the expected risk-free rate.[51] Third, Mr. Gorman, Ms. Reno, and Ms. LaConte each rely on Blume-adjusted Beta coefficients reported by Value Line.[52]

Q. ARE CAPM RESULTS DEVELOPED BY CERTAIN INTERVENOR WITNESSES REASONABLE?

A. No, they are not. In particular, Mr. Ellis' CAPM result (5.41 percent) is well below the lowest authorized ROE for any electric utility in the last 40 years.[53] Estimates as low as 5.41 percent are nearly 100 basis points *below* the reported cost of debt for utilities in October 2022.[54] Debt investors require a return commensurate with the risk that the company will fail to meet that obligation. However, equity investors bear the residual risk associated with ownership, and have a claim on cash flows only after debt holders are paid. As such, equity holders bear greater risk and therefore require a higher return. The fact that

50 Direct Testimony of Michael P. Gorman, at 54; Direct Testimony of Billie S. LaConte at 8; Direct Testimony of Maureen L. Reno at 35; Direct Testimony of Mark E. Ellis, at 68.

51 Direct Testimony of Michael P. Gorman, at 54.

52 Direct Testimony of Michael P. Gorman, at 54-55; Direct Testimony of Maureen L. Reno, at 38-39; Direct Testimony of Billie S. LaConte, at 8.

53 Source: S&P Capital IQ Pro, Regulatory Research Associates.

54 The Moody's Utility Bond Index for Baa-rated Utility debt was as 6.34 percent as of October 31, 2022 (Source: Bloomberg Professional).

Mr. Ellis' CAPM analysis produces a result that is well below debt returns demonstrates his inputs are unreasonable and his results should be disregarded.

1. Risk-free rate

Q. MR. ELLIS QUESTIONS THE ACCURACY OF INTEREST RATE FORECASTS AND OBJECTS TO YOUR USE OF A PROJECTED 30-YEAR TREASURY BOND YIELD AS THE RISK-FREE RATE.[55] HOW DO YOU RESPOND?

A. As explained earlier in this rebuttal testimony and in my direct testimony, I believe the use of projected 30-year Treasury bond yields as the risk-free rate in the CAPM analysis is appropriate because interest rates are expected to continue increasing as the Federal Reserve unwinds its balance sheet and tightens monetary policy. Notably, both the current and projected risk-free rates presented in my direct testimony (2.72 percent and 3.40 percent, respectively) are well below the 30-day average 30-year Treasury yield of 3.92 percent as of October 31, 2022. In addition, I do not share Mr. Ellis' concerns with the accuracy of projected bond yields. This is because the cost of equity depends on what investors expect, not what actually happens.[56] Nonetheless Mr. Ellis has not presented any evidence that current interest rates are any more accurate at predicting future interest rates *in the long-term*.

Further, even though I do not agree with the exclusive reliance on the current average Treasury bond yield as the risk-free rate, I note using current bond yields in the CAPM model produces results (shown in Exhibit JMC-5.2) well above the DCF model results and much higher than the CAPM results put forth by Mr. Gorman, Ms. Reno, Ms. LaConte, and Mr. Ellis. My conclusion is that it is reasonable and appropriate to use the projected 30-year Treasury bond yield as the risk-free rate.

55 See, Direct Testimony of Mark E. Ellis, at 51-55.

56 See, 147 FERC ¶ 61,234, Docket No. EL11-66-001, Opinion No. 531 Order on Initial Decision, at para 88 (June 19, 2014).

Q. WHAT IS YOUR RESPONSE TO MR. GORMAN'S CRITICISM THAT YOUR PROJECTED LONG-TERM RISK-FREE RATE IS "UNREASONABLE"?[57]

A. Mr. Gorman's criticism is puzzling. His CAPM estimate of 9.88 percent relied upon to develop his recommended ROE range uses a *higher* projected risk-free rate of 3.60 percent from Blue Chip published on August 1, 2022 than my 3.40 percent projected risk-free rate that he criticizes. If his position is that his higher projected long-term risk-free rate of 3.60 percent is more current than the risk-free rates I used in my direct testimony in the current market environment, I agree. Further, projected risk-free rates align with Georgia Power's 2023 test year and Alternative Rate Plan that would be effective through 2025, contrary to Mr. Gorman's position.

2. Beta

Q. HOW DO THE INTERVENOR WITNESSES ESTIMATE BETA?

A. As discussed above, Ms. LaConte and Ms. Reno each rely on current Value Line Beta coefficients.[58] Mr. Gorman considered current Value Line Beta coefficients before ultimately relying on a historical quarterly average of Value Line Beta coefficients between Q3 2014 and Q2 2022.[59] Mr. Ellis relies on Zacks and Yahoo! Finance estimates of Beta that are calculated based on monthly returns, rather than the weekly convention used by Value Line and that I use with Bloomberg.

Q. MR. GORMAN OBSERVES THAT CURRENT BETA COEFFICIENTS FROM VALUE LINE ARE HIGHER THAN THE HISTORICAL AVERAGE FOR THE ELECTRIC UTILITY INDUSTRY.[60] DO YOU VIEW THIS AS A REASON TO ADJUST THE CURRENT BETA COEFFICIENTS?

57 Direct Testimony of Michael P. Gorman, at 73.
58 Direct Testimony of Billie S. LaConte, at 8; Direct Testimony of Maureen L. Reno, at 38.
59 Direct Testimony of Michael P. Gorman, at 57.
60 Direct Testimony of Direct Testimony of Michael P. Gorman, at 55-57.

A. No, I do not. Beta is the measure of relative risk in the CAPM analysis. The utility industry has typically had lower than average Beta coefficients because utilities generally tend to be less volatile than the broad market. However, as discussed in my direct testimony,[61] that was not the case during the market dislocation that occurred in response to the COVID-19 pandemic. Five-year Beta coefficients from both Value Line and Bloomberg increased substantially in February and March 2020 to levels not seen since the financial crisis of 2008/2009 and have remained at those elevated levels ever since.[62] In my view, there is no reason to use the longer-term average Beta coefficients, as suggested by Mr. Gorman. I have used Value Line and Bloomberg Beta coefficients calculated using five years of weekly return data against a broad market index (either the S&P 500 or the NYSE Composite). This five-year period pre-dates the COVID-19 period by 2.5 years, which suggests that the proxy group Beta coefficients are being affected by factors other than the pandemic.

As discussed in my direct testimony, electric utilities have not served as a safe haven for investors during the recent economic downturn.[63] According to Mr. Gorman's Exhibit__(MPG-20) pages 2-5, Beta coefficients for the proxy group and the electric and natural gas utilities have stabilized at elevated levels since Q3 2020, contradicting Mr. Gorman's position that utilities' higher Beta coefficients are the result of just two anomalous months in March and April 2020.[64] In my opinion, this shift may also be attributable to the market's recognition of the complex challenges facing the industry in response to climate change, transitioning to a lower carbon generation mix, grid modernization, and shifting consumer preferences.

Further, I do not agree with Mr. Ellis' concerns with Value Line's methodology for calculating Beta coefficients, including the time period over which Betas are calculated, the market index, and the Blume adjustment. I note that Beta is a measure of relative risk

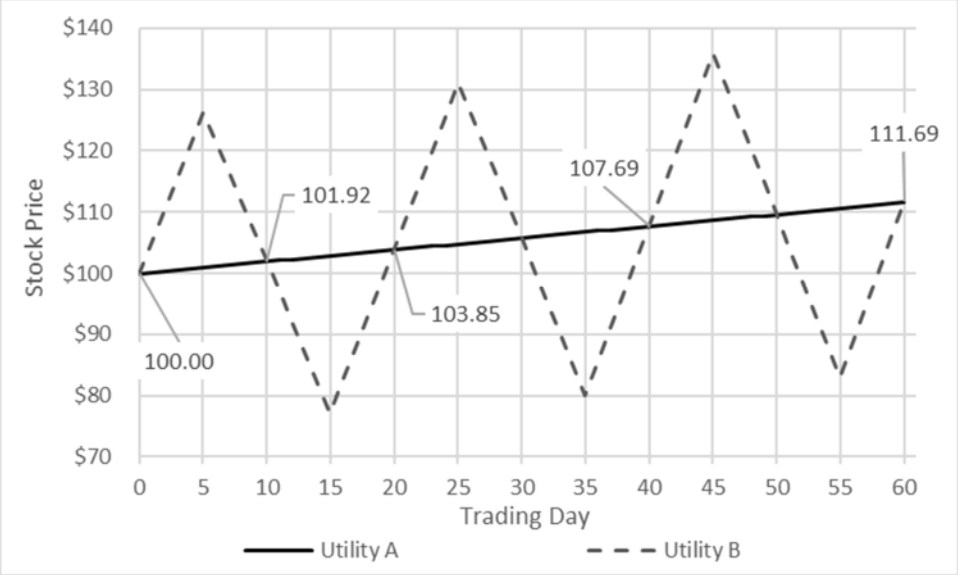
61 Direct Testimony of James M. Coyne, at 13-14.
62 *Ibid*., at 32-33.
63 *Ibid*, at 13-14.
64 Direct Testimony of Michael P. Gorman, at 55.

in the CAPM analysis. While utilities have underperformed the broader market since January 2020, Beta coefficients demonstrate that utilities have traded more in line with the broad market than they have historically, indicating that utility investors recognize the structural shifts affecting the industry.

Q. WHAT IS YOUR RESPONSE TO MR. ELLIS' USE OF MONTHLY BETAS REPORTED BY YAHOO! FINANCE AND ZACKS?

A. By their nature, Beta coefficients calculated using monthly returns do not capture intra-month return volatility and could lead one to conclude utility stock returns are more stable than they actually are. Consider, for example, stock prices for two utilities – Utility A and Utility B – over a 60-trading day period (roughly three calendar months), illustrated in Figure 12 below. Both utilities start trading at a price of $100 per share. Both utilities report a stock price return of 11.69 percent at the end of three months. At the end of every month (the 20th trading day), both stocks have the same price. However, Utility B's stock price is clearly more volatile (and therefore riskier) than Utility A's.

Figure 12: Illustrative Example of Weekly vs. Monthly Stock Volatility



If the Beta coefficient for Utility B was calculated using monthly returns, it would not capture intra-month stock price volatility and Utility B's Beta coefficient would be the

same as Utility A's. On the other hand, if the Beta coefficients were calculated using weekly returns (every five trading days), Utility B's Beta coefficient would be higher than Utility A's, all else equal, better reflecting its higher volatility. In other words, Mr. Ellis suggests that the Commission should ignore evidence of increasing volatility and risk for utility companies, and the proxy group specifically.

3. Market Risk Premium

Q. THE INTERVENOR WITNESSES CHALLENGE THE FORWARD-LOOKING MARKET RISK PREMIUM YOU USED IN YOUR CAPM ANALYSIS.[65] CAN YOU PLEASE RESPOND TO THEIR CONCERNS?

A. The use of a forward-looking or projected market risk premium ("MRP") is appropriate because the historical average market risk premium does not reflect the inverse relationship between interest rates and the equity risk premium. The Ibbotson data used to calculate the historical MRP of 7.46 percent indicates that the long-term average return on large company stocks from 1926-2021 was 12.33 percent, while the average income-only return on government bonds was 4.87 percent over the same period.[66] It is therefore not reasonable to use the historical MRP when the current average yield on the 30-year Treasury bond is *lower* than the bond yield used to calculate the historical MRP. With interest rates at these levels, the forward-looking MRP should be *higher* than 7.46 percent.

Second, the method I have used to calculate the forward-looking MRP is similar to the methodology used by FERC in Opinion No. 531-B.[67] Specifically, the forward-looking MRP in my CAPM analysis is derived by calculating the expected total return for the companies in the S&P 500 Index less the projected risk-free rate. Ms. LaConte adjusts my forward-looking MRP to exclude companies with negative growth rates and growth rates above 20 percent. However, when investors purchase the S&P 500 Index or a mutual fund

65 Direct Testimony of Michael P. Gorman, at 71-72; Direct Testimony of Billie S. LaConte, at 7-8; Direct Testimony of Maureen L. Reno, at 37-38; Direct Testimony of Mark E. Ellis, at 67-68.

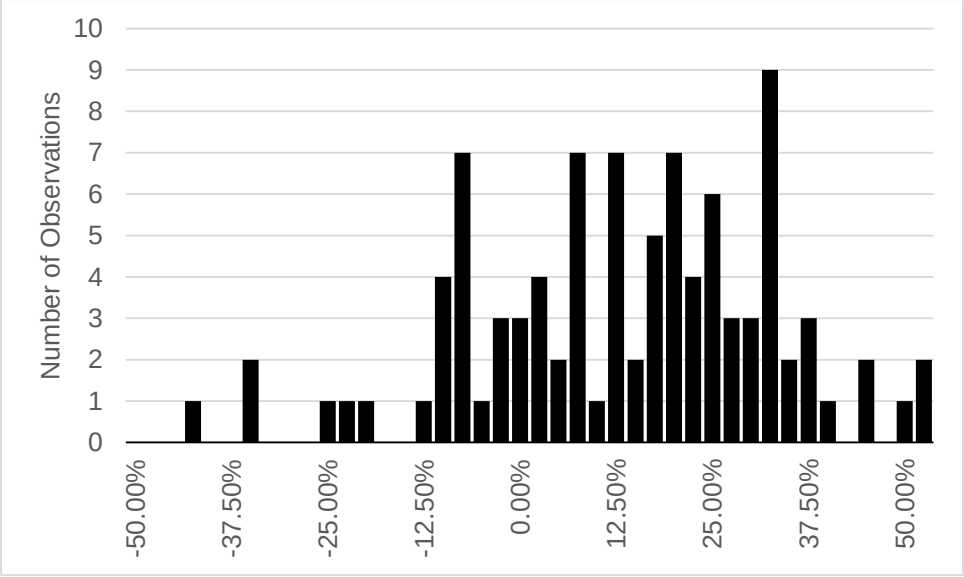
66 Source: Kroll, 2022 SBBI Yearbook, at Appendix A-1, A-7.

67 *See MISO Transmission Owners, et al. v. FERC*, No. 16-1325 (Aug. 9, 2022) (slip op.) at 17-24 (upholding FERC's CAPM methodology).

or exchange traded fund that mirrors the S&P 500 Index, their total return is based on the returns for all 500 companies in the S&P 500 Index, not only those companies with positive EPS growth rates or growth rates less than 20 percent. Further, my MRP calculation is internally consistent because the Betas used in my CAPM analysis are calculated against all companies in the S&P 500 Index or the NYSE Composite Index, not just against those companies that have positive growth rates or growth rates less than 20 percent.

The Intervenor Witnesses argue that the total market return used in my forward-looking MRP calculation are not reasonable. To assess their reasonableness, I analyzed the annual performance of the S&P 500 from 1926-2021. As shown in Figure 13 below, the actual return on the S&P 500 Index has exceeded 15 percent in 50 percent (48 out of 96) of the years from 1926-2021. These data demonstrate that actual total returns for the broad market greater than 15 percent are not uncommon.

Figure 13: Total Returns of S&P 500 Index – 1926-2021[68]



Q. MR. GORMAN, MS. LACONTE, AND MS. RENO APPLY MARKET RISK PREMIA BASED ON HISTORICAL DATA.[69] **HOW DO YOU RESPOND?**

68 Source: Kroll, 2022 SBBI Yearbook, Appendix A-1.

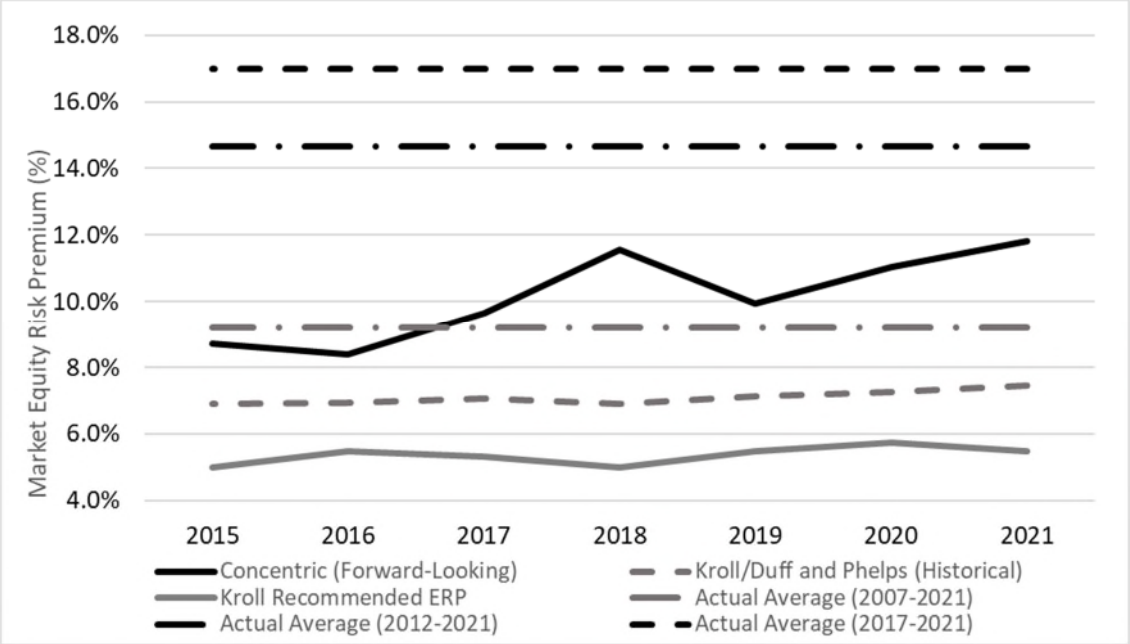
69 Direct Testimony of Michael P. Gorman, at 57-56; Direct Testimony of Billie S. LaConte, at 8; Direct Testimony of Maureen L. Reno, at 36-37.

A. As explained earlier, the use of a historical market risk premium is not appropriate under current market conditions because it does not reflect the inverse relationship between interest rates and the equity risk premium, nor the earnings growth for today's S&P 500 companies. When the current average yield on U.S. Treasury bonds is *below* the long-term historical average yield, it is reasonable to expect that the MRP would be *above* the historical average market risk premium. Consequently, the long-term average historical market risk premium would be appropriate only if the expected risk-free rate was similar to the long-term historical risk-free rate. Further, equity market returns calculated over the last century do not represent the growth available today to U.S. companies from international markets and the roles of technology and innovation in driving earnings growth.

Q. DO YOU AGREE WITH MR. GORMAN AND MS. RENO'S REFERENCE TO KROLL'S RECOMMENDED EQUITY RISK PREMIUM OF 5.50 PERCENT?

A. No, I do not. As a case in point, Figure 14 below demonstrates just how far off Kroll's recommended market equity risk premium has been over the past seven years in relation to the forward-looking approach I have used. Kroll's recommended market equity risk premium has substantially underestimated actual market performance over several averaging periods.

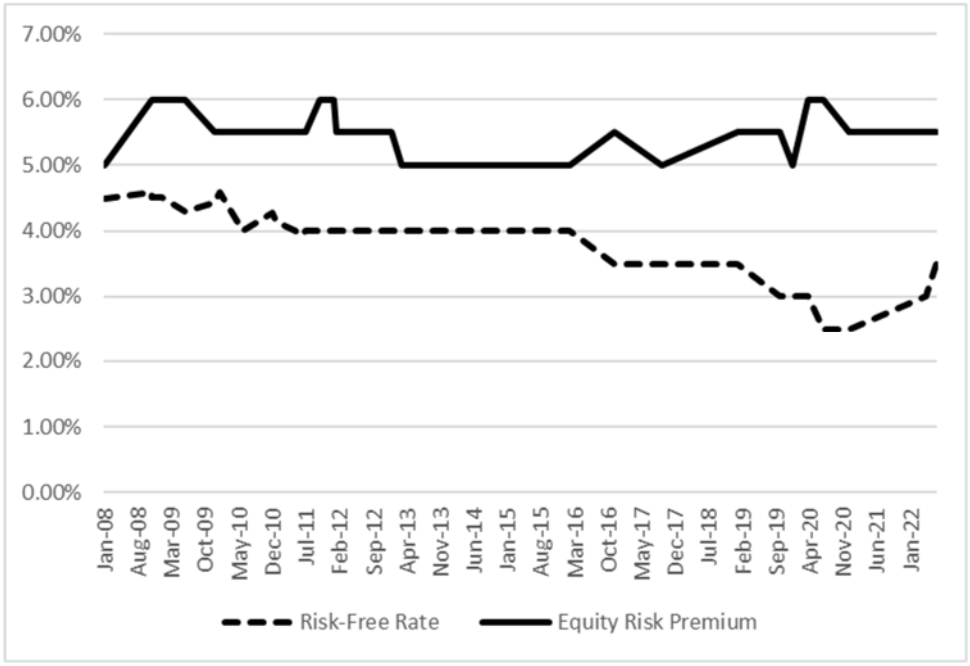
Figure 14: Market Equity Risk Premium Methods



Further, it is not clear that Kroll develops its recommended market equity risk premium in relation to its risk-free rate. Because the market equity risk premium is a function of the market return and the risk-free rate at a point in time, the market equity risk premium is related to the risk-free rate (as explained earlier, there is an inverse relationship between the two). As Figure 15 below shows, there is no apparent relationship[70] between Kroll's recommended market equity risk premium and risk-free rate.

70 The R-square between the Kroll's "normalized" risk-free rate and recommended equity risk premium between 2008-2022 is 0.09 percent and statistically insignificant.

Figure 15: Kroll's Recommended Market Equity Risk Premium and Risk-Free Rate (2008-2022)[71]



Q. WHAT IS YOUR CONCLUSION WITH REGARD TO THE CAPM?

A. My conclusion is that using reasonable forward-looking inputs for the risk-free rate and MRP, along with current Betas from Value Line and Bloomberg, the CAPM is producing results that should be considered along with the results from the DCF, Risk Premium, and Expected Earnings models.

C. RISK PREMIUM MODEL

Q. THE INTERVENOR WITNESSES CHALLENGE THE USE OF A RISK PREMIUM MODEL SUCH AS THE ONE YOU HAVE PRESENTED, OR THEY CONTEND THAT YOUR APPLICATION OF THE RISK PREMIUM MODEL IS NOT REASONABLE.[72] HOW DO YOU RESPOND TO THEIR CONCERNS?

71 Kroll, 2022 Cost of Capital Navigator.

72 *See, e.g.*, Testimony of Michael P. Gorman, at 74-76; Direct Testimony of Billie S. LaConte, at 10-11; Direct Testimony of Maureen L. Reno, at 40-41; and Direct Testimony of Mark E. Ellis, at 3, 28-32.

A. Mr. Gorman expresses several concerns with my Risk Premium analysis, including: (1) he disputes the inverse relationship between interest rates and risk premia; (2) he claims that, while academic studies have shown that in the past there was such an inverse relationship, the relationship has changed over time, particularly since interest rate volatility is not as extreme as it was in the 1980s; and (3) he contends that I have ignored investment risk differentials in my regression analyses, and that my adjustment to the equity risk premium is based exclusively on changes in nominal interest rates.[73]

In response to Mr. Gorman's first concern, there is a large body of research in addition to my own statistical analyses that supports the inverse relationship between interest rates and equity risk premia, including the March 1998 article published by Dr. S. Keith Berry, which came to similar conclusions regarding the inverse relationship between interest rates and the risk premia.[74] Several other studies were published after those that Mr. Gorman cites as evidence that this inverse relationship is a relic of the 1980s. As summarized in Dr. Roger Morin's *New Regulatory Finance*, two of these studies were published in 2005, demonstrating that the inverse relationship between interest rates and the equity risk premium are contemporary concepts in finance:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates—rising when rates fell and declining when interest rates rose. The reason for this relationship is that when interest rates rise, bondholders suffer a capital loss. This is referred to as interest rate risk…. Conversely in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fears of loss of earning power dominate, the risk differential will widen and hence the risk premium will increase.[75]

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73 Direct Testimony of Michael P. Gorman, at 74-76.

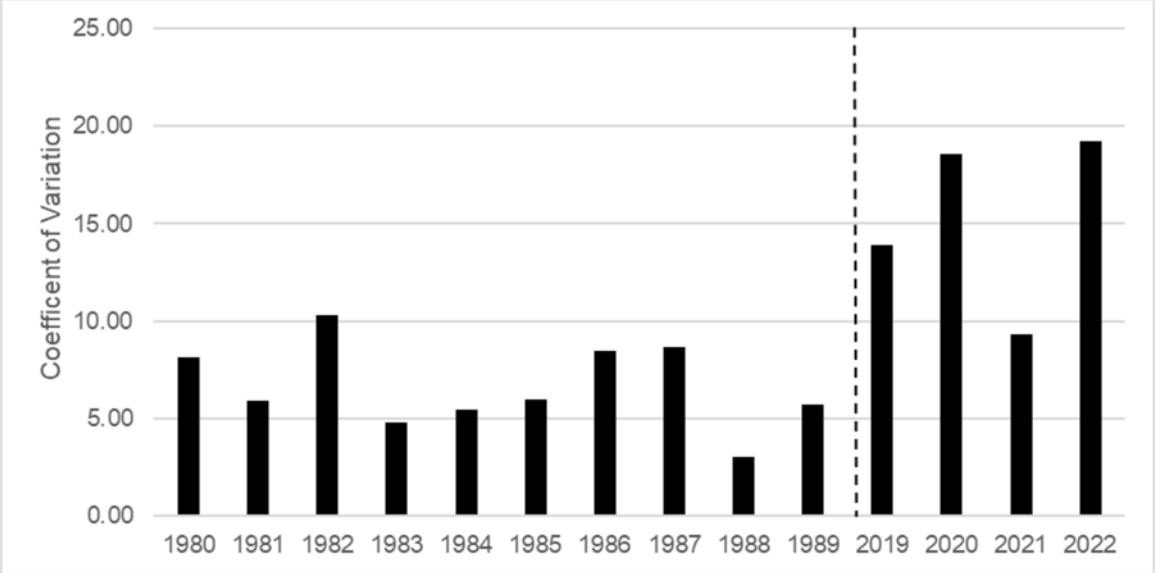
74 *See e.g.*, S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates.

75 Morin, Roger A., New Regulatory Finance, Public Utilities Reports, Inc. (2006), at 128.

Furthermore, my Risk Premium analysis has an R^2 of approximately 0.84, which indicates that there is a high degree of correlation between the observed equity risk premium and changes in interest rates.

With regard to Mr. Gorman's statement that interest rate volatility was more extreme in the 1980s than it is today, I conducted an analysis that compares the volatility in 30-year Treasury bond yields in each year during the 1980s to the volatility from 2019 to present. As shown in Figure 16, the relative standard deviation of Treasury bond yields is substantially higher in 2022 than it was during any year in the 1980s, indicating that interest rate volatility is higher in recent years than it was in the 1980s, and has been higher since 2019 than all but one year during the 1980s (i.e., 1982).

Figure 16: Treasury Bond Yield Volatility[76]



In response to Mr. Gorman's third concern, he contends that I have ignored investment risk differentials in my regression analyses, and that my adjustment to the equity risk premium is based exclusively on changes in nominal interest rates. I agree that my analysis is based solely on the relationship to interest rates, as is Mr. Gorman's Risk Premium analysis. Mr. Gorman's Risk Premium analysis also does not consider any other variables except average

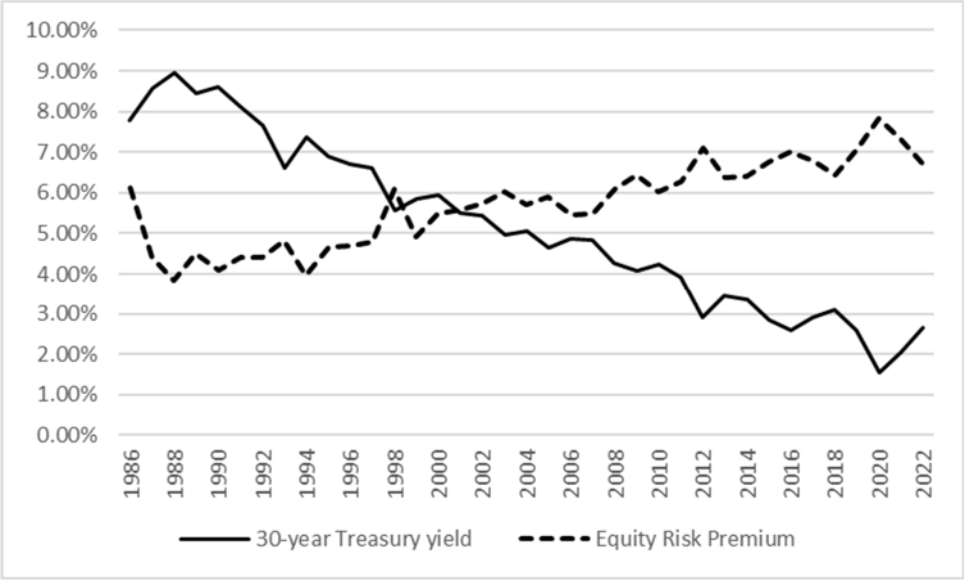
76 Source: Bloomberg Professional.

authorized ROEs and bond yields. In my analysis, with an R^2 of 0.84, the relationship to interest rates accounts for 82 percent of the change in awarded ROEs, which is quite strong. In addition, the inclusion of 682 rate cases over a 30-year period provides a broad perspective on case-specific issues. To the extent that shifts in industry risk are left out of this equation, the recent increases in utility betas would suggest that the Risk Premium results are biased downwards, and would likely understate the cost of equity. This relationship is picked up directly, however, in the CAPM model, and these results are meaningfully higher. Therefore, I believe the model is useful as a method to estimate the cost of equity for electric utilities like Georgia Power, along with the results from the DCF, CAPM, and Expected Earnings models.

Q. DOES MR. GORMAN'S RISK PREMIUM ANALYSIS SUPPORT THE INVERSE RELATIONSHIP BETWEEN THE EQUITY RISK PREMIUM AND BOND YIELDS?

A. Yes, it does. Mr. Gorman's Risk Premium analysis is conceptually similar to mine in that he calculates the risk premium as the difference between authorized ROEs and Treasury bond yields (as well as utility bond yields). As Figure 17 below shows, Mr. Gorman's annual 30-year Treasury bond yield and indicated risk premium data in Exhibit__(MPG-16) show a strong negative, inverse relationship.

Figure 17: Mr. Gorman's Treasury Bond Yield and Indicated Risk Premium[77]



Q. MS. LACONTE ADJUSTS YOUR RISK PREMIUM ANALYSIS TO COMBINE THE LONG-TERM AVERAGE EQUITY RISK PREMIUM OF 6.06 PERCENT WITH YOUR PROJECTED 30-YEAR TREASURY BOND YIELD. IS HER ADJUSTMENT APPROPRIATE?

A. No, it is not. The risk premium model is designed to adjust the risk premium for any given level of bond yield, based on the historical relationship between the two variables over the last 30 years. Adding the long-term average to a current or projected bond yield does not appropriately reflect the statistical relationship between the equity risk premium and 30-year Treasury bond yield. As noted earlier in my discussion of the market risk premium in the CAPM, the equity risk premium and bond yields are inversely related. The only time the historical average equity risk premium is appropriate is when the current or projected bond yield is approximately equal to the historical average bond yield. Ms. LaConte's adjustment to my Risk Premium analysis is inappropriate and should be rejected.

77 Exhibit__(MPG-16).

D. EXPECTED EARNINGS ANALYSIS

Q. BEFORE RESPONDING TO THE CRITICISMS OF YOUR EXPECTED EARNINGS ANALYSIS, DO ANY OF THE INTERVENOR WITNESSES PERFORM A SIMILAR ANALYSIS?

A. Yes, Ms. Reno's Comparable Earnings Model ("CEM") reviews historical and forecasted earned returns on book value and market-to-book ratios for the same proxy group of companies that I use. Her 2025-2027 proxy group projected CEM results of 10.50 percent to 10.86 percent are reasonably consistent with my Expected Earnings results presented in Exhibit JMC-7 that range from 11.03 (mean) to 11.08 percent (median). However, Ms. Reno does not give these results any weight in developing her 9.47 percent recommendation, which forces her overall ROE recommendation downward.

Q. PLEASE SUMMARIZE THE INTERVENOR WITNESSES' POSITIONS WITH THE USE OF AN EXPECTED EARNINGS ANALYSIS TO ESTIMATE THE COST OF EQUITY FOR GEORGIA POWER IN THIS PROCEEDING.[78]

A. Mr. Gorman, Mr. Ellis, and Ms. LaConte disagree with the Expected Earnings analysis because they believe it does not measure the market cost of equity capital. In addition, Mr. Gorman contends that "the earned return on book equity is simply not an accurate or legitimate basis upon which to determine a fair and reasonable return on equity for both investors and customers."[79] Mr. Ellis further asserts that it has been rejected by the FERC and therefore is not appropriate.

Q. WHAT IS YOUR RESPONSE TO THESE CONCERNS RELATED TO THE EXPECTED EARNINGS APPROACH?

A. The Expected Earnings approach provides an expected return for like-risk companies, which is a core strength of the model and consistent with the basic tenets of *Hope*, which

78 Direct Testimony of Michael P. Gorman, at 77-78; Direct Testimony of Billie S. LaConte, at 11-12; and Direct Testimony of Mark E. Ellis, at 3, 29-32.

79 Direct Testimony of Michael P. Gorman, at 78.

requires that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." In the context of considering regulated utility investment opportunities, an investor would naturally consider both current market valuations in deciding between companies of like risk and the value of the expected return on book value.

The *Hope* and *Bluefield* standards establish that a utility should be granted the opportunity to earn a return that is commensurate with the return on other investments of similar risk. However meritorious the theoretical criticism of the Expected Earnings methodology in the context of comparing non-utility investments, the Intervenor Witnesses fail to acknowledge the regulated utility's authorized book return does, in fact, materially affect the earnings and earnings growth of a regulated utility. The Expected Earnings approach provides valuable insight into the opportunity cost of investing in Georgia Power's electric utility operations precisely because of the regulated context of electric utility investment opportunities.

If investors decide to devote capital to the Company (which would offer a return of only 5.54 percent on book value if Mr. Ellis' recommendation was adopted), they forgo the opportunity for that same capital to earn a potentially greater return on book value through investment in the proxy companies. As a result, the Expected Earnings approach is informative because it provides a measure of the return on book value that is available to investors through other investments with comparable risk to Georgia Power.

As Dr. Morin explains, the Expected Earnings approach (also referred to as the Comparable Earnings approach below and by Ms. Reno) is highly meaningful in a regulatory setting similar to the one being used to set the cost of equity for Georgia Power:

> The Comparable Earnings approach is far more meaningful in the regulatory arena than in the sphere of competitive firms. Unlike industrial companies the earnings requirement of utilities is determined by applying a percentage rate of return to the book value of a utility's investment, and not on the market value of that investment. Therefore, it stands to reason that a different percentage rate of return than the market cost of capital be applied when the investment base is stated in book value terms rather than market

> value terms. In a competitive market, investment decisions are taken on the basis of market prices, market values, and market cost of capital. **If regulation's role was to duplicate the competitive result perfectly, then the market cost of capital would be applied to the current market value of rate base assets employed by utilities to provide service. But because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful.**[80]

Further, in developing his sustainable growth rates for the DCF model, Mr. Gorman assumes the reasonableness of the projected returns on book equity from Value Line for the proxy group companies, which are the same returns that he dismisses as unreliable in the Expected Earnings analysis.

Lastly, although the FERC has not included the Expected Earnings analysis in its most recent orders setting its ROE methodology (i.e., Opinion Nos. 569-A and 569-B) for electric transmission companies, FERC has left the door open for presentation of an Expected Earnings analysis on a case-by-case basis.[81] In my view, the Expected Earnings analysis provides a more stable picture of the returns that investors are expecting for companies in the Electric Utility sector based on Value Line data. This stability is due to Value Line's analysis and projections which change when updated, in contrast to the CAPM and DCF results which shift with more volatile market data. Moreover, as explained in this section, the use of accounting returns is appropriate because the authorized ROE is being applied to an accounting rate base in order to determine the net income a company is authorized to recover in rates. For all of these reasons, I continue to support the use of an Expected Earnings analysis as one model to estimate the cost of equity for Georgia Power in this proceeding.

80 New Regulatory Finance, Roger A. Morin Ph.D., Public Utility Reports, 2006, at 394-395. (emphasis added)

81 Federal Energy Regulatory Commission, Opinion No. 569-A, Order on Rehearing, issued May 21, 2020, at para. 132.

V. CAPITAL STRUCTURE AND COST OF DEBT

Q. PLEASE SUMMARIZE THE INTERVENOR WITNESSES' CAPITAL STRUCTURE RECOMMENDATIONS.

A. Ms. Reno accepts the Company's proposed capital structure.[82] Mr. Gorman accepts Georgia Power's requested capital structure for 2023 until Vogtle units 3 and 4 are in service. He recommends, however, that the Commission authorize an equity ratio of 51 percent for 2024 and 2025.[83] Ms. LaConte recommends the Commission authorize a capital structure that consists of no more than 53 percent common equity.[84] Lastly, Mr. Ellis recommends a capital structure of 61.70 percent with his 5.54 percent ROE recommendation.[85]

As to the cost of long-term debt, only Ms. Reno rejects the Company's proposed cost of debt. She recommends that Georgia Power's proposed 2023 cost of debt of 3.53 percent be applied for the entire term of the Alternative Rate Plan (ARP) and that the cost of debt should not increase in 2024 and 2025.[86]

Q. ON WHAT BASIS DOES MR. GORMAN DEVELOP HIS RECOMMENDED 51 PERCENT EQUITY RATIO FOR 2024 AND 2025?

A. Mr. Gorman's recommendation is based on his review of authorized equity ratios for electric and gas utilities between 2010 and 2022, as well as adjusted debt ratios reported by S&P for electric gas, and water utilities. He concludes that adjusting Georgia Power's ratemaking capital structure to reflect a 51 percent equity ratio in 2024 and 2025 "would

82 Direct Testimony of Maureen L. Reno, at 6.
83 Direct Testimony of Michael P. Gorman, at 23-24.
84 Direct Testimony of Billie S. LaConte, at 23.
85 Direct Testimony of Mark E. Ellis, at 5.
86 Direct Testimony of Maureen L. Reno, at 17-18.

be consistent with the normalized industry ratemaking capital structure" and support the Company's current bond rating, or even improve it.[87]

Q. MR. GORMAN'S RECOMMENDATION TO REDUCE GEORGIA POWER'S RATEMAKING CAPITAL STRUCTURE IN 2023 AND 2024 IS BASED, IN PART, ON A REVIEW OF NATIONAL AVERAGE AUTHORIZED CAPITAL STRUCTURE FOR ELECTRIC AND NATURAL GAS UTILITIES.[88] PLEASE COMMENT ON THAT COMPARISON.

A. Mr. Gorman's analysis is not an apples-to-apples comparison to Georgia Power's proposed capital structure. First, his analysis includes authorized equity ratios for all rate case types reported by Regulatory Research Associates, including electric T&D rate cases and limited issue rate rider rate cases that are not base rate cases.[89] Electric T&D utilities have a different risk profile than vertically integrated electric utilities. As Figure 18 shows, the average annual authorized equity ratios for vertically integrated electric utilities are higher than Mr. Gorman's annual averages that include electric T&D utilities.

87 Direct Testimony of Michael P. Gorman, at 31-32.

88 Direct Testimony of Michael P. Gorman, at 29-30.

89 Mr. Gorman's Confidential WP 21.

Figure 18: Average Authorized Equity Ratios (2010 – 2022)

Year	All Electric Utilities[90]	Vertically Integrated Electric Utilities
2010	49.49%	50.13%
2011	49.09%	49.93%
2012	51.45%	52.37%
2013	50.12%	51.09%
2014	50.28%	51.24%
2015	50.24%	50.99%
2016	49.70%	50.04%
2017	50.02%	50.99%
2018	50.60%	51.29%
2019	51.54%	52.16%
2020	50.94%	52.02%
2021	51.01%	51.12%
2022	51.54%	51.97%

Further, although Mr. Gorman removed rate case decisions from states that include non-investor supplied capital in the ratemaking capital structure,[91] his analysis includes decisions that, unlike Georgia Power, also use short-term debt in the ratemaking capital structure, biasing the authorized equity ratio downward.

Nonetheless, the range of authorized equity ratios for vertically integrated electric utilities reported by RRA since 2010 has been from 40.25 percent to 59.09 percent.[92] Georgia Power's proposed equity ratio of 56.00 percent is well within this range and is therefore not unreasonable. Notably, Mr. Gorman's Table 7 shows an upward trend in the average

90 Mr. Gorman's Table 7, updated for rate cases decided through November 3, 2022.

91 Specifically, Arkansas, Florida, Indiana, and Michigan.

92 Source: S&P Capital IQ Pro, Regulatory Research Associates. I have excluded decisions in Arkansas, Florida, Indiana, and Michigan, which include zero cost capital items that are not part of investor-provided capital.

authorized equity ratio between 2010 and 2022. Particularly important is the increase since 2016, in part to somewhat mitigate the effects of the Tax Cuts and Jobs Act on utilities' cash flows and their credit profiles.

VI. BUSINESS RISK AND FLOTATION COSTS

Q. DO YOU AGREE WITH MR. GORMAN'S CONTENTION THAT CREDIT RATINGS TAKE INTO ACCOUNT ALL BUSINESS AND FINANCIAL RISKS THAT ARE RELEVANT TO INVESTORS?[93]

A. No. Credit ratings, while important, are not the only consideration in assessing business or financial risk, and the risks for equity investors are not the same as the risks for bondholders. Credit ratings are assessments of the likelihood a company could default on its *debt*, whereas, the purpose of setting an ROE is to determine the riskiness and cost of the Company's *equity*. Equity investors are more concerned with earnings and rate base growth, regulatory support for recovery of prudently incurred costs, the strength of the local economy and housing markets, capital spending, changes in interest rates, changes in long-term weather patterns, and more recently exposure and opportunities related to decarbonization of the industry. Bondholders are primarily concerned with stability and predictability of cash flows and timeliness of cost recovery as those affect a utility's ability to meet its fixed obligations.

S&P states that it puts a negative ratings modifier on Georgia Power and ranks the Company at the lower end of S&P's range for the excellent business risk category based upon Georgia Power's exposure to energy transition risk and the risks associated with the completion of Vogtle.[94] Further, while I have considered Georgia Power's relative regulatory risk, it is important to recognize that I did not make an adjustment to my ROE recommendation for business risk. Instead, I relied on the mean results of the four financial models I used to estimate the cost of equity for Georgia Power.

93 Direct Testimony of Michael P. Gorman, at 79-80.

94 S&P Global Ratings, *Georgia Power Company*, November 18, 2021 at 6.

Q. SEVERAL INTERVENOR WITNESSES ARGUE THAT THE COMPANY'S ALTERNATIVE RATE PLAN AND RATE STRUCTURES MITIGATE GEORGIA POWER'S RISK.[95] WHAT IS YOUR RESPONSE?

A. It is important to remember that the cost of equity is a comparative analysis. As such, the relevant point of comparison is the Company's risk relative to its peers. As explained in my direct testimony and shown in Exhibit JMC-9, a substantial majority of the proxy group companies employ a variety of rate structures and mechanisms to mitigate regulatory lag. As demonstrated in my direct testimony, the regulatory structures available to Georgia Power are no different from the perspective of the investment community than those in place at the proxy companies.[96] As a result, Georgia Power is no less risky than the proxy companies on account of its regulatory mechanisms. Therefore, contrary to these Intervenor Witnesses, my testimony and recommendation accounts for Georgia Power's regulatory mechanisms.

Q. THE INTERVENOR WITNESSES DISAGREE WITH THE INCLUSION OF FLOTATION COSTS. WHY IS IT APPROPRIATE AND NECESSARY TO CONSIDER FLOTATION COSTS IN THE AUTHORIZED ROE?

A. Flotation costs are the direct out-of-pocket costs associated with the sale of new issues of common stock. In the same way that costs associated with debt issuances are recovered through the cost of debt, equity issuance costs should also be recovered. Flotation costs are not expenses, so they do not appear on the income statement. Instead, they are reflected on the balance sheet under "Paid in Capital." Further, flotation costs are accumulated over time and remain on the balance sheet even if no new equity issuances are planned. For these reasons, I continue to include an adjustment for flotation costs in my ROE recommendation.

95 *See, e.g.*, Billie S. LaConte, at 15-17; Direct Testimony of Maureen L. Reno, AT 24-25.

96 Direct Testimony of James M. Coyne, at 42-43.

VII. CONCLUSIONS

Q. WHAT ARE YOUR CONCLUSIONS REGARDING A FAIR ROE FOR GEORGIA POWER?

A. The only reliable method for determining the cost of capital is through the application of rigorous analysis using financial models and market data from reliable sources. Additionally, the Commission's cost of capital determination should consider the general economic and capital market environment and the influence capital market conditions exert over the results of the ROE estimation models. Interest rates on government and utility bonds have increased substantially in 2022 and projections suggest a continued upward pressure in the coming years. This increase in the capital costs, and other risk factors indicate that the uncertainty and volatility in financial markets have caused equity investors to require a higher rate of return, including for electric utilities.

My recommended ROE of 11.0 percent and capital structure with a common equity ratio of 56.0 percent is fair and reasonable for Georgia Power. This capital structure is consistent with the Company's actual equity ratio, and combined with the authorized ROE will support continued financial strength and access to debt and equity capital to meet the Company's operating requirements.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

REBUTTAL TESTIMONY OF

STEVEN M. FETTER

ON BEHALF OF GEORGIA POWER COMPANY

DOCKET NO. 44280

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Steven M. Fetter. My business address is 1240 West Sims Way, Port Townsend, Washington 98104.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony to the Georgia Public Service Commission (the "Commission") on behalf of Georgia Power Company ("Georgia Power" or the "Company") on June 24, 2022.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the following points testified to by Kevin O'Donnell and Michael Gorman in their direct testimonies on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff ("PIA Staff"):

- I draw a different conclusion than Mr. O'Donnell when he states, "As can be seen in the above chart [Chart 1], most utilities are in the A-, BBB+, and BBB range." (page 5);

- I disagree with Mr. O'Donnell's assessment that, "As can be seen in Table 3 Georgia Power's credit rating is similar to other southeast electric utilities." (pages 5-6);

- Mr. O'Donnell is not accurate when he states that the position I took in the 2019 rate case about potential downgrades was shown to be inaccurate by an S&P downgrade of Georgia Power on October 27, 2021, and a Moody's downgrade "on August 8, 2019, just prior to the final order being issued in the last Company rate case in December, 2019." (pages 19-24);

- Mr. O'Donnell's reference to the Moody's downgrade noted above is inaccurate: it is off by twelve months. Moody's downgraded Georgia Power on August 8, 2018, not August 8, 2019, and thus the negative rating action occurred 16 months prior to the Commission's Final Order in the 2019 rate case. (page 20);

- I disagree with Mr. O'Donnell's rejection of my views related to Georgia Power's credit ratings because this rejection is based solely on his quantification of interest costs compared to rate costs to consumers; by adopting this approach, Mr. O'Donnell ignores the approximate 50% weighting of qualitative factors that is part and parcel of the analysis and assignment of credit ratings. (pages 24-27);

- I disagree with Mr. Gorman's financial recommendations of authorized ROE of 9.45% and equity layer moving down to 51%. (page 2); and

- I disagree with Mr. Gorman when he states, "Mr. Fetter provided no substance or evidence that supports his conclusion that GPC's credit rating and financial integrity are only achieved if the Company's return on equity and proposed ratemaking capital structure are adopted." (page 27)

III. DISCUSSION

Q. WHAT IS YOUR OVERALL CONCLUSION IN THIS REBUTTAL TESTIMONY?

A. Georgia Power's credit ratings now straddle above and below the bottom of my recommended credit rating range of ratings no lower than BBB+. For this reason, I encourage the Commission to set Georgia Power's equity level and authorized return on equity consistent with Mr. Coyne's recommendation of an 11% ROE and the Company

(Abramovitz/Adams/Houston/Robinson) Panel's recommendation of 56% equity ratio. In my opinion, the Company's recommendations are designed to maintain the Company's financial integrity with the potential of improvement over time.

Mr. O'Donnell supports PIA Staff witness Gorman's recommended 9.45% ROE with an equity layer that sinks down from 56% to 51%. I agree with Company witnesses Abramovitz and Adams that Mr. O'Donnell's recommendations would result in significant movement down from Georgia Power's current financial position.[1] Mr. O'Donnell's recommendations, if adopted, would also result in a negative impact to the qualitative side of credit rating analysis. In short, Mr. O'Donnell's recommendation would represent such a stark undermining of the Company's financial integrity that it would likely be interpreted by the rating agencies as an abrupt departure from the Commission's long record of constructive regulation characterized by consistency and gradualism in balancing the interests of customers and investors and would be very detrimental to the Company's overall credit rating profile.

Q. MR. O'DONNELL PROVIDES TWO TABLES IN HIS TESTIMONY TO SUPPORT HIS VIEW THAT ALL IS WELL AT GEORGIA POWER. YOU INDICATE THAT YOU DISAGREE WITH HIS ASSESSMENT. PLEASE EXPLAIN.

A. In both Table 3 ("Georgia Power Comparison to Southeast Electric Utilities") and Chart 1 ("Utility Credit Ratings"), Mr. O'Donnell attempts to show a stable ratings environment for Georgia Power by submitting an incomplete picture. Based solely on his Table 3, Mr. O'Donnell states: "Georgia Power's credit rating is similar to other southeast electric utilities." (pages 5-6). This is not accurate. Mr. O'Donnell's Table 3 ignores the Company's

[1] Witnesses Abramovitz and Adams also discuss how Mr. Gorman has not appropriately considered the concept of debt imputation that the credit rating agencies utilize to factor into their calculation of credit metrics debt-like instruments and circumstances that increase a utility's obligations and financial risk. That process has been a focus of the rating agencies dating back to at least the early 1990s.

lowest rating, BBB from Fitch. Below I have provided a version of his list, modified to include Fitch ratings, to show the disparity I have described:

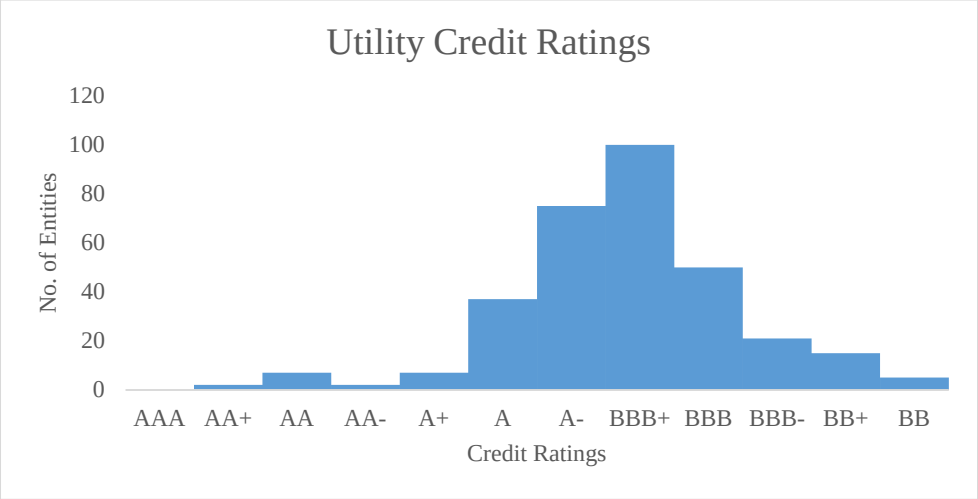
Utility	Moody's	S&P	Fitch
Florida Power & Light	A1	A	A
Alabama Power	A1	A-	A
Duke Energy Carolinas	A2	BBB+	NR
Mississippi Power	Baa1	BBB+	BBB+
Georgia Power	Baa1	BBB+	BBB

As the above chart demonstrates, in contrast to Mr. O'Donnell's assertion that Georgia Power has similar credit ratings to "other southeast electric utilities," the ratings from the three major rating agencies place the Company at the *bottom* of the list of southeast electric utilities, with a cumulative eight rating notches below Florida Power & Light and seven notches below Alabama Power.

Q. IN ADDITION, DO YOU BELIEVE THAT MR. O'DONNELL'S CHART 1 FURTHER SUPPORTS YOUR CONCERNS ABOUT GEORGIA POWER'S CREDIT RATINGS?

A. Yes. Mr. O'Donnell's Chart 1 is provided below:

Chart 1: Utility Credit Ratings



Source: Data estimated from S&P Ratings Direct Chart sent to Nova Energy Consultants on Sept. 28, 2022

Here is a breakdown of the number of utilities at each rating level:

Rating Level	Number of Utilities
AA	7
A+	7
A	37
A-	75
BBB+	100
BBB	50
BBB-	21

Investment Grade Dividing Line

BB+: 15

BB: 5

In Discussing his Table 1, Mr. O'Donnell states: "As can be seen…, most utilities are in the A-, BBB+, and BBB range." (page 5). In view of my longstanding position that regulated utilities should target having credit ratings no lower than BBB+, I think a more appropriate analysis of this chart shows that the majority of regulated utilities hold ratings of BBB+ or above – 226 – as compared to those rated below BBB+ – 91. In fact, those below BBB+ include 41 at levels no utility management, investor, or regulator would find to be acceptable: 20 below investment grade, plus 21 at the very precarious lowest investment grade rating level of BBB-. For these marginally rated utilities, one operational or financial setback, one major storm, or one cyber security attack could drive the utility below investment grade, requiring a substantial number of its investors to modify their equity/debt holdings. With Georgia Power straddling that BBB+ / BBB dividing line, now is not the time to adopt a position – as advocated by Mr. O'Donnell – that would all but guarantee that Georgia Power would for the short- and medium-term remain among the precarious marginal utilities that have little to no financial margin to mitigate the impacts of unforeseen adverse events.

Q. IN DESCRIBING YOUR TESTIMONY FROM THE COMPANY'S 2019 RATE CASE, DID MR. O'DONNELL MISCHARACTERIZE ANY PART OF YOUR TESTIMONY?

A. Yes. In reference to my testimony during the 2019 Georgia Power rate case, Mr. O'Donnell incorrectly states: "The high ROE and equity ratio in the last rate case did not, contrary to Mr. Fetter's statements in the 2019 case, prevent a credit downgrade." (page 24). First and importantly, Mr. O'Donnell is factually incorrect. In his testimony Mr. O'Donnell stated that the Moody's downgrade occurred "on August 8, 2019, *just prior to the final order being issued in the last Company rate case in December, 2019*." This statement is not accurate. The Moody's downgrade was announced on August 8, ***2018***, which was 16 months *before* the Commission's December 2019 decision in the Georgia Power rate case, and, indeed, more than a year before the initial hearing and before PIA Staff filed any testimony in the 2019 rate case. At the same time, prior to the 2019 rate case, S&P (on March 25, 2017) and Fitch (on September 28, 2018) had already placed Negative outlooks on their Georgia Power ratings, signaling the potential direction of a credit rating change within the foreseeable future. The timing of the Moody's action and those Negative outlooks are relevant. They indicate that the financial strength of the Company had already been weakening well before the 2019 rate case, and they help explain why, after a relatively supportive regulatory decision at the end of 2019, downgrades at S&P and Fitch might occur.

In addition to this inaccuracy, Mr. O'Donnell completely mischaracterizes my 2019 rate case testimony to the Commission. Below is a full quote from my 2019 testimony:

> In order for Georgia Power to be able to maintain its current ratings range across all three agencies, I encourage the Commission to set the ROE and capital structure at levels consistent with Dr. Vander Weide's recommendations. Such a Commission determination would show a continuation of the strong regulatory support that Georgia Power has long experienced, which should avoid further weakening in the Company's credit profile. On the other hand, a less than constructive decision by the Commission in this case could lead to further negative credit rating actions, potentially moving the Company below the 'BBB+' / 'Baa1' rating level that I have long testified represents the lowest appropriate credit rating level for a U.S. regulated utility. (pages 22-23).

What is important to note is that in my prior testimony, I was referring to Dr. James Vander Weide's recommendation that the Commission set an authorized ROE of 10.9% with an equity level of 56%. The Company ultimately agreed to a settlement resolving all issues except the Company's set point ROE and equity ratio, which were deferred to the

Commission, which authorized an ROE of 10.5% and an equity ratio of 56%. Even though my recommendation was superseded by the settlement, I was still hopeful that the lower, albeit still supportive, Commission-ordered financial parameters would overcome the pending Negative outlooks at S&P and Fitch. Unfortunately, they could not, with S&P bringing Georgia Power's rating to BBB+ and Fitch going even lower at BBB. (Moody's, of course, had acted long before both my testimony and the Commission decision.) I still firmly believe that the financial enhancement that would have been provided by Dr. Vander Weide's recommended 10.9% ROE level could have forestalled Fitch's move to BBB, below my recommended range of no lower than BBB+.

Q. YOU ALSO CHALLENGE MR. O'DONNELL'S APPROACH OF FOCUSING ON THE FINANCIAL SIDE OF CREDIT RATINGS WITHOUT CONSIDERING THE QUALITATIVE FACTORS INVOLVED IN THE RATINGS PROCESS. PLEASE EXPLAIN.

A. While credit rating agencies certainly give great weight to financial metrics when formulating their credit ratings, Mr. O'Donnell has not given appropriate consideration to qualitative rating factors, most especially "Regulation." Based on my leadership role at a major rating agency, I know that the qualitative assessment is given virtually equal weight as the quantitative factors in coming to a rating determination. As I discussed in my direct testimony, "Regulation" is the most important qualitative factor. Mr. O'Donnell supports Mr. Gorman's proposed significant downward movement in Georgia Power's financial measures, while both of them ignore the qualitative impacts. This is a mistake, and, in my view, has resulted in incomplete analyses by those two witnesses. If adopted by this Commission, Mr. Gorman's recommendations would represent a clear break from the Commission's past constructive decision-making. The likely result would be negative actions by the rating agencies as they recognize both the less supportive financial measures as well as qualitative judgments pointing toward a potential reordering of the state's regulatory philosophy.

Q. WOULD SUCH A MAJOR RESETTING OF THE GEORGIA REGULATORY CLIMATE HAVE A SIGNIFICANT EFFECT ON GEORGIA POWER'S DAY-TO-DAY OPERATIONS?

A. Yes, and the key reason is "Access" to the capital markets. During the past 15 years, we have seen even "A"-rated utilities encounter issues regarding access to capital markets during times of stress such as the 2008-2009 recession and the economic concerns that accompanied the early onset of the COVID contagion. At cross-examination of my direct testimony, I shared the story of Entergy New Orleans ("ENO") pre-and-post Hurricane Katrina. Prior to Katrina, ENO was a financially improving regulated utility that had solidified its Moody's credit rating at the Baa3 investment-grade level with expected near-term positive movement. Katrina hit New Orleans during the last week of August 2005. Within three weeks, ENO's rating had fallen to Ca, far below investment-grade level. With its access to the capital markets completely shut off, parent Entergy Corp. moved ENO into bankruptcy, which then opened the way for the parent to begin funding ENO's long struggle back toward financial stability. It is important to note that all of my talk about the precarious nature of BBB- ratings can be seen within ENO's saga – that utility has had its ups and downs since Katrina, but as of now, 17 years later, ENO sits below investment grade in the Ba / BB category at both Moody's and S&P.

With access in mind, I attempted to follow Mr. O'Donnell's complex financial analysis (pages 25-27) about the cost of a downgrade compared to the potential cost to customers resulting from this rate case. I found it interesting that, if I understand his methodology correctly, Mr. O'Donnell is calculating Georgia Power's potential movement down through the BBB category, with each step equal in financial pain. Thus, he sets the cost of a downgrade from Baa1 to Baa2 as 14 basis points of interest, resulting in additional financing cost for the Company of $96 million. He then compares this to his hypothetical calculated increased customer rate cost of $1.26 billion. He at no time states that a Baa1 utility (which would be within my recommended range) would be a much more attractive investment target for the financial community than would be the declining number of utilities holding Baa2 ratings. I have always believed that the best way to test a hypothesis that

appears compelling, but which one fears might be suspect, is to take the assumptions another step further, and even still further (eventually to absurd levels), which I will proceed to do.

I noted earlier the precarious situation a regulated utility would find itself in with a rating of Baa3 – the lowest investment-grade level and thus the bane of investors who fear that one notch down puts the rating "off a cliff." Taking Mr. O'Donnell's assumptions, financing at the anxiety-producing Baa3 level would cost another 14 basis points, or $96 million more, providing this comparison: additional financing costs of $192 million compared to consumer costs of $1.26 billion. Now, let's take this to the absurd level – Georgia Power and its regulators, with the encouragement of some intervenors, decide to allow the Company's credit rating to free fall to below investment-grade level at BB. The chart below demonstrates the differential in the cost of 10-year debt going down into the junk bond level of the BB category over the past decade.

		10-Year A Utility Index	10-Year BBB Utility Index	10-Year BB Utility Index
12/30/2011	**YE '11**	3.14%	4.05%	6.25%
12/31/2012	**YE '12**	2.66%	3.38%	5.26%
12/31/2013	**YE '13**	3.83%	4.48%	6.05%
12/31/2014	**YE '14**	3.12%	3.46%	5.22%
12/31/2015	**YE '15**	3.56%	4.02%	6.79%
12/30/2016	**YE '16**	3.39%	3.71%	5.71%
12/29/2017	**YE '17**	3.22%	3.43%	4.61%
12/31/2018	**YE '18**	3.98%	4.48%	6.98%
12/31/2019	**YE '19**	2.80%	3.12%	4.51%
12/31/2020	**YE '20**	1.82%	1.97%	3.10%
12/31/2021	**YE '21**	2.43%	2.63%	3.37%
10/28/2022	**Current**	5.61%	6.06%	6.77%

Source: Bloomberg

As this chart shows, the increase in interest cost between the BBB and BB categories varies depending upon capital markets conditions but approximately spans the range of 10% to 60% more. I would estimate that a significant percentage of investment institutions would no longer be permitted to invest in such below investment-grade bonds – or would have to modify their current holdings going forward. Utilizing the above data, one could multiply the negative cost of Mr. O'Donnell's one-notch downgrade analysis by 100% and *still* show a preference for the increased

interest costs at close to $400 million for the three-notch downgrade versus consumer rate costs of $1.26 billion, all the while basically eliminating most of the outside financing access then available to the Company. At cross-examination on his testimony, Mr. O'Donnell even suggested that if the Company's ratings were to fall too low to access traditional financing, there would always be the option to run its multi-billion-dollar business using private placement financing, usually reserved to fund construction of individual plants or projects.[2] Mr. O'Donnell's suggestion stretches access to capital markets far beyond logical reasoning and does not equate to the required level of access on reasonable terms.

The bottom line is that credit rating analysis is not solely a numbers game. Rating agencies weigh quantitative and qualitative factors on a virtually equal basis, so only looking at quantitative factors will not render an appropriate strategy, nor will only focusing on qualitative factors, most especially regulation, provide a valid plan. The two sides must be weighed equally, which I have done in every one of the cases in which I have testified, using the same fairness parameters whether I was testifying for a regulated utility, a public utility commission, or a consumer advocate.

Q. MR. GORMAN CLAIMS THAT YOU PROVIDE "NO SUBSTANCE SUPPORTING OR EVIDENCE THAT SUPPORTS [YOUR] CONCLUSION THAT GPC'S CREDIT RATING AND FINANCIAL INTEGRITY ARE ONLY ACHIEVED IF THE COMPANY'S RETURN ON EQUITY AND PROPOSED RATEMAKING CAPITAL STRUCTURE ARE ADOPTED." PLEASE COMMENT ON THIS STATEMENT.

A. Mr. Gorman is wrong. And if I may, I would like to begin my answer to Mr. Gorman's claim by offering a serious and critical question: "Where would Georgia Power – and its customers and, indeed, the state of Georgia – be now if, instead of approving the settlement and setting authorized ROE at 10.5% with a 56% equity layer, the regulators in 2019 had adopted Mr. Gorman's recommendation of authorized ROE of 9.25% with equity at 51%?" Purely on a financial analytical basis, I expect the Company would have probably been just

[2] PSC Docket No.44280 GPC 2022 Rate Case (11/10/2022); Day 3 of Cross Examination, time stamp 3:49:30.

slightly "north" of the investment-grade / non-investment grade dividing line at BBB- / Baa3. But when the negative qualitative effects were layered in, junk bond status would likely not have been out of the question. With Vogtle so close to completion now (assisted by that supportive 2019 rate case settlement and Commission approval), I cannot imagine that the small increment of rate relief flowing from Mr. Gorman's position back then would have balanced out the negative effects of Georgia Power's impaired capital markets access, higher interest costs for multiple years to come, and a degree of doubt whether Vogtle would have been able to progress to the point of knocking on the door of startup. Those are the facts upon which I stand now, as the Commission is faced with almost the very same question – whether to accept Mr. O'Donnell's financial proposals for short-term rate gain, or solidify the Company's current ratings, with positive movement likely with the successful startup of Vogtle.

IV. CONCLUSION

Q. MR. FETTER, DO YOU HAVE ANY CONCLUDING THOUGHTS?

A. Yes, I do. I have testified before the Georgia Public Service Commission for almost two decades. As a former Commission Chairman and head of a major utility ratings practice, I have respected this Commission's commitment to adjudicating cases with a long-term vision, one that incorporates both quantitative and qualitative factors. Accordingly, for the reasons stated above, my recommendation remains the same as in my direct testimony. The Commission should maintain its longstanding commitment to constructive regulation, which has provided the Company a framework within which to attract capital and provide quality service to customers, while also taking the steps necessary to move forward when unexpected impediments have arisen.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

REBUTTAL TESTIMONY OF

LEE EVANS AND LARRY LEGG

ON BEHALF OF

GEORGIA POWER COMPANY

DOCKET NO. 44280

I. INTRODUCTION

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

A. Lee Evans, Director of Demand Planning & Analysis for Southern Company Services, Inc. ("SCS"). My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. Larry T. Legg, Director of Pricing and Rates for Georgia Power Company ("Georgia Power" or the "Company"), 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

Q. MR. LEGG AND MR. EVANS, DID YOU PREVIOUSLY PRESENT DIRECT AND SUPPLEMENTAL DIRECT TESTIMONY AND EXHIBITS ON BEHALF OF GEORGIA POWER IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to respond to recommendations made by the Georgia Public Service Commission's ("Commission") Public Interest Advocacy ("PIA") Staff and Intervenors as they relate to rate design and cost-of-service. The fact that we may not specifically address a particular recommendation made by PIA Staff or an Intervenor should not be construed as support for such position.

Q. ARE YOU PROVIDING ANY EXHIBITS TO YOUR TESTIMONY?

A. No.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. As part of our longstanding commitment to meet our customers' energy needs, Georgia Power offers our customers an extensive portfolio of more than 40 individual electric service base rate options from which to choose, with multiple options available for customers of differing sizes and classes. These rate offerings, including the changes proposed by Georgia Power in this rate case, will enable the Company to continue providing customers with clean, safe, and reliable electricity at prices that are below the national average. While a more thorough discussion of the issues we address on rebuttal appears in the following sections of our testimony, here we provide a general summary of our testimony with respect to a number of key issues.

Residential Rates

Notably, and for the avoidance of doubt, the Company is *not* proposing to discontinue the Residential Service ("R") tariff; rather, the Company proposes to make the rate unavailable to new residential premises that establish service after December 31, 2022. Georgia Power also opposes the structural changes to the R rate proposed by PIA Staff, as these changes would fundamentally alter the rate for the more than 1.8 million customers currently taking service under the rate without due consideration of this impact.

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, such as Time of Use Residential Demand ("TOU-RD"), with price signals that more accurately reflect the cost of electric service for customers. 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, in addition to TOU-RD as the default residential rate. Contrary to the assertions of PIA Staff and certain intervenors, the TOU-RD rate is designed to be revenue neutral and not cost customers more than the

R rate. Because the TOU-RD rate provides better price signals, customers are able to make more informed decisions about their energy use and can save on their electric bills by shifting usage or staggering the use of key appliances.

Commercial and Industrial Rates

The Company's commercial and industrial rates continue to be appropriately structured, and the Company does not agree with the proposed changes to these rates. PIA Staff's recommendation that customers on marginal rates should be assessed the fully embedded cost of the Environmental Compliance Cost Recovery ("ECCR") tariff is fundamentally inconsistent with how marginal rates like Real-Time Pricing ("RTP") are designed to operate and should be denied. 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. To include fully embedded costs such as ECCR in the marginal portion of the rates like RTP would undermine the rate structure and significantly decrease the appeal of the rate to current and future customers. Altogether, PIA Staff's recommendation to include ECCR in marginal RTP prices, as well as their recommendation to recover ECCR costs on a per kWh basis rather than as a percent of base revenue, results in an overall increase to the RTP tariffs of $150 million. The Commission should reject both recommendations. The Commission should also reject Department of Defense Witness Blank's recommendation to modify the Company's criteria for the reduction of CBLs for customers who install behind the meter generation because customer generation does not permanently remove the customer's load and does not justify the reduction of a customer's CBL.

Community Solar

The Commission should approve the Company's requested increase to the Community Solar block prices as agreed to by PIA Staff, since the purpose of this program is to support the development of renewable energy but does not guarantee bill savings. In addition, the Georgia Coalition of Local Government's ("Coalition") proposed price reduction is premised on a misunderstanding of how the program operates and should be rejected.

Charge It Electric Vehicle Tariff

The Commission should also approve the Charge It Electric Vehicle ("CIEV") tariff, as agreed to by PIA Staff, as an appropriately structured and time limited offering to encourage the growth of electric vehicles ("EVs") in Georgia.

Cost-of-Service Study

The Company's cost-of-service study ("COSS") continues to reasonably allocate the Company's revenue requirement across retail rates based on principles of cost causation. Georgia Power's continued use of a 12 coincident peak ("12-CP") methodology to allocate production costs is reasonable and appropriately recognizes the Company's need to plan and operate its system in every month of the year. Staff and Intervenor proposals to replace the 12-CP method with an energy-based allocation method or summer-focused allocation method are neither compelling nor justified.

Parity Adjustments

Finally, the Company is supportive of general movement towards parity but not the rate specific adjustments proposed by PIA Staff or Georgia Association of Manufacturers ("GAM") Witness Pollock. Instead, the Company supports parity adjustments rooted in the Company's COSS that are made at the rate group rather than individual rate level.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?

A. Our testimony is organized as follows:

- Section II (pages 5 to 11) discusses proposed changes to residential rates;
- Section III (pages 11 to 14) discusses proposed modifications to commercial rates;
- Section IV (pages 14 to 18) discusses proposed changes to the Community Solar and CIEV tariffs;
- Section V (pages 18 to 19) discusses the Company's proposed Interconnection Application Fee;

- Section VI (pages 19 to 20) discusses hourly interval data;
- Section VII (pages 20 to 22) discusses proposed changes to the COSS; and
- Section VIII (page 23) discusses proposed parity adjustments.

II. RESIDENTIAL RATES

Residential Service "R" Tariff

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED CHANGES TO THE R RATE.

A. As Mr. Legg states in his Direct Testimony, the Company proposes to update the R tariff to make the rate unavailable to newly constructed residential premises that establish service on Georgia Power's electric system after December 31, 2022. This update will encourage residential customers to adopt more modern rate structures with price signals that more accurately and appropriately reflect the cost of electric service. However, the R tariff will remain available to residential premises for which electric service is established prior to January 1, 2023.

As part of its commitment to customer satisfaction, Georgia Power has actively promoted the variety of residential rate options it offers to help customers select the rate that best fits their needs. As a result, customer adoption of residential rate options such as the TOU-RD (also known as "Smart Usage"), TOU-PEV, Pay by Day ("PBD"), and FlatBill tariffs has increased significantly. Indeed, the number of residential customers who have chosen to participate in a time-of-use rate has increased by more than 250%. Many customers have demonstrated a preference for these rate plans, which are designed to provide customers with options that best meet their needs. By closing the R rate to new premises, the Company will continue to gradually transition new residential accounts onto the other rates within the Domestic Group that better align with the cost to serve customers.

Q. IS PIA STAFF PROPOSING ANY MODIFICATIONS TO THE R RATE?

A. Yes. PIA Staff proposes to eliminate the declining block rates during non-summer months and move to a flat rate for all kilowatt hour ("kWh") usage.

Q. DO YOU AGREE WITH PIA STAFF'S RECOMMENDATION TO REPLACE THE DECLINING WINTER BLOCK RATE STRUCTURE WITH A FLAT ENERGY RATE?

A. No. Notably, the Commission has declined to adopt this recommendation in each of the last two rate cases and should continue to do so in this case. Although the price signal the R rate sends is not as strong as more recent tariff designs, the Company originally designed the R rate to reflect the seasonality of costs to serve residential customers. The inclining price blocks in June through September appropriately reflect the fact that the Company's costs are higher in the summer months. Importantly, the inclining price structure provides incentives for energy efficiency and conservation. The declining block structure in the winter months recognizes that off-peak costs are generally lower and, therefore, provides price signals to reflect this reality. The declining block structure provides an economical option for customers choosing to use electric 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.

Q. ARE THERE OTHER CONCERNS WITH PIA STAFF'S PROPOSAL TO SIGNIFICANTLY MODIFY THE R RATE?

A. Yes. PIA Staff is proposing significant modifications to the R rate without providing any analysis or discussion of the impacts these changes would have on the large number of customers who are currently on that rate. Currently, more than 1.8 million customers take service on the R rate, and it is not clear that PIA Staff has considered how their proposed modifications will impact these customers or what steps should be taken to educate customers prior to the implementation of such changes. PIA Staff is proposing to fundamentally alter the rate through which Georgia Power's largest number of customers

are being served, without due consideration of the impact to those customers. Further, the R rate design is antiquated and sends poor price signals to customers about the cost of the electricity they consume, as compared to the Company's newer rate designs. Thus, it makes no sense to fundamentally alter the longstanding R tariff while customers are transitioning to more modern rates that more appropriately reflect the cost of electric service for customers.

Q. IS THE COMPANY PROPOSING TO ELIMINATE THE R RATE?

A. No. The Company is ***not*** proposing to eliminate the R rate. Under the Company's proposal, customers currently on the R rate will be able to remain on the rate. Customers currently on the R rate who subsequently move to another existing premises will also be able to remain on the rate. The Company is only proposing to close the R rate for new residential premises that initially establish service with Georgia Power after December 31, 2022. This incremental change in the availability of the R rate is a measured and logical step in Georgia Power's gradual movement towards more modern rate designs that send price signals that more appropriately reflect the cost of electric service for customers.

Q. ASIDE FROM THE R RATE, WHAT OTHER RATE OPTIONS ARE AVAILABLE FOR CUSTOMERS AT A NEW PREMISES?

A. If the Company's proposal is adopted, customers at new residential premises can choose from the Company's other residential rate options, which include TOU-RD, TOU-PEV, or PrePay. Additionally, once those premises have twelve months of service history, customers can also select the Company's FlatBill or Pay by Day rates.

Q. DOES THE COMPANY HAVE ANY FEEDBACK FROM CUSTOMERS REGARDING THEIR EXPERIENCE ON TOU-RD?

A. Yes. Customer surveys have shown that, as compared to customers on the R rate, 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.

These same surveys showed that TOU-RD customers had an overall higher satisfaction score for Georgia Power as compared to R rate customers.

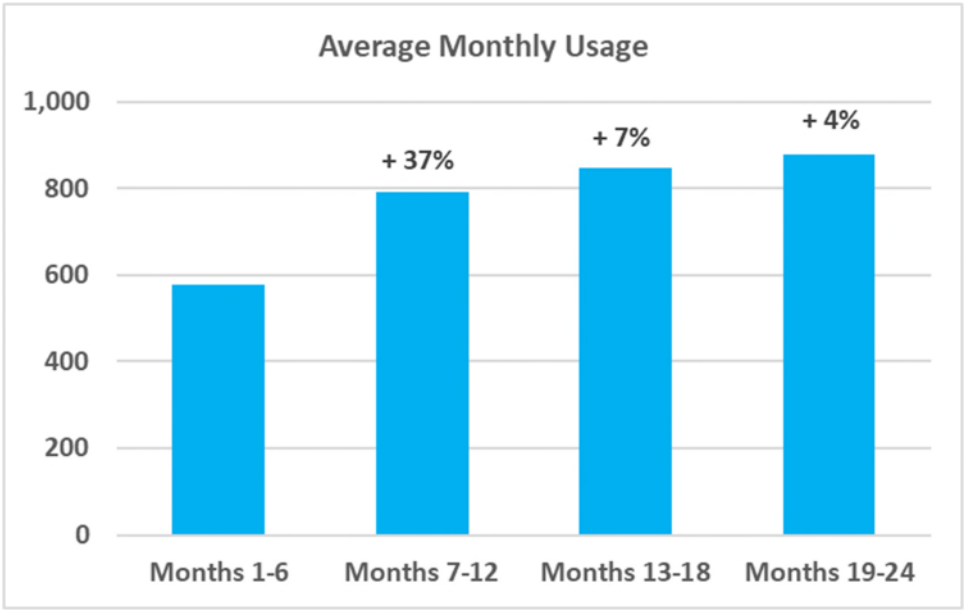
Q. IS THE TOU-RD RATE INHERENTLY MORE COSTLY FOR CUSTOMERS THAN THE R RATE, AS CLAIMED BY PIA STAFF AND INTERVENORS?

A. No. The TOU-RD rate is not designed to cost customers more than the R rate; rather, the TOU-RD rate was designed to be revenue neutral for the average customer – meaning that the average customer would pay the same annual bill amount on the TOU-RD rate as they would on the R rate. 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 or staggering the use of key appliances. As a result, customers receive more efficient economic signals regarding their usage and energy choices.

Q. IS THE BILL COMPARISON NOTED IN PIA STAFF'S TESTIMONY AN APPROPRIATE REPRESENTATION OF THE PRICE IMPACTS OF THE TOU-RD RATE AS COMPARED TO THE R RATE?

A. No. As new premises are added to the Georgia Power system, it can take anywhere from one to two years for the premises' monthly usage to normalize. This ramp-up period could be due to numerous factors, including the timing of home construction, installation of appliances, or occupancy. Because the bill comparisons that Staff highlight in their testimony represent premises that are new to our system, the average monthly usage for those premises is far below the level to which the usage will ultimately mature (see Figure 1). Therefore, the bill comparisons used by Staff are heavily skewed by extremely low usage and therefore fail to tell a complete story.

Figure 1



As Figure 1 above demonstrates, a customer's average monthly usage will increase continually for the first 24 months of existence on Georgia Power's system. 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." By allowing the 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.

Q. AS COMPARED TO THE R RATE, WHY ARE THREE-PART RATES – LIKE TOU-RD – MORE COST-REFLECTIVE?

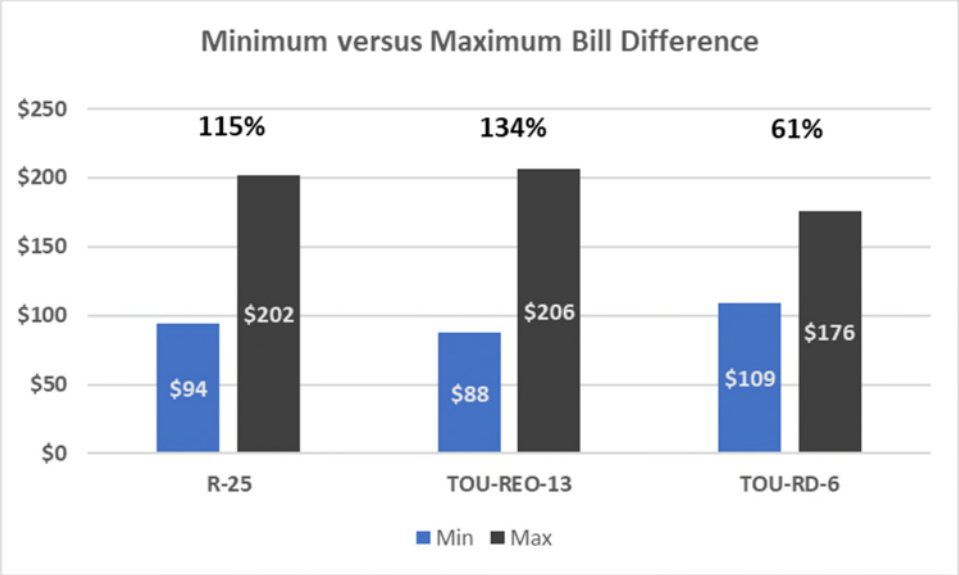
A. Costs to serve our customers are divided into three components: (1) customer-related costs; (2) demand-related costs; and (3) energy-related costs. To ensure our rates most accurately reflect the cost-of-service, all three cost components should be accounted for within the design of a rate. As such, 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. 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 results in less efficient use of the electric system by customers and higher prices overall.

Q. WHY IS THE TOU-RD RATE A BETTER DEFAULT RATE THAN TOU - RESIDENTIAL ENERGY ONLY ("TOU-REO") AS PROPOSED BY GSEIA, SEIA, AND VOTE SOLAR?

A. As described above, TOU-RD is a modern, three-part rate that sends price signals that more accurately and appropriately reflect the cost of electric service. In addition, the TOU-RD rate is more stable than the TOU-REO rate from a monthly billing standpoint, meaning that it has a smaller margin between minimum and maximum bills during an annual period. Figure 2 below provides an example of the bill volatility between the R, TOU-REO and TOU-RD rates for the average residential customer and shows that TOU-RD is much less volatile than either the TOU-REO or the R Rate when comparing the difference between minimum and maximum bills over a given year.

Figure 2



Q. WHY IS IT APPROPRIATE TO INCREASE THE BASIC SERVICE CHARGE AS PART OF THE COMPANY'S REQUEST?

A. The increased basic service charge better aligns with the Company's costs to serve customers. As stated by Mr. Legg during the Company's direct hearings, Georgia Power has proposed to increase all traditional base rates on an equal percentage basis, including rate elements. This includes the residential basic service charge, which recovers the customer-related costs the Company incurs to serve a customer, regardless of the amount of energy that customer may use. As proposed, the monthly increase to the basic service charge would be approximately $2.27 for a residential customer.

Q. DOES THE COMPANY AGREE WITH STAFF'S PROPOSAL TO INCREASE THE INCOME QUALIFIED SENIOR CITIZEN DISCOUNT BY THE AMOUNT OF ANY INCREASE TO THE BASIC SERVICE CHARGE?

A. Yes.

III. COMMERCIAL RATES

Q. DO YOU AGREE WITH PIA STAFF'S RECOMMENDATION THAT CUSTOMERS ON MARGINAL RATES SHOULD BE ASSESSED THE FULL EMBEDDED COST OF THE ENVIRONMENTAL COMPLIANCE COST RECOVERY ("ECCR") TARIFF?

A. No. Staff's recommendation is fundamentally inconsistent with how marginal rates like RTP are designed to operate. 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. The ECCR costs include coal combustion residual asset retirement obligations ("CCR ARO") that are fully embedded costs incurred by the Company independent of a customer's kWh usage. As such, they are appropriately recovered through the CBL portion of marginally priced rates. To include fully embedded costs such as ECCR in the marginal portion of the RTP rate would not only undermine the

rate structure, but also prevent these rates from actually functioning as marginal rates. The hourly prices would no longer reflect marginal costs or real-time prices.

Q. WHAT WOULD HAPPEN IF ECCR COSTS WERE ALLOCATED TO THE MARGINAL PORTION OF RTP AND OTHER INCREMENTAL RATES?

A. 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. 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. 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.

Q. DOES PIA STAFF'S PROPOSED 50% MOVEMENT OF ECCR IN INCREMENTAL RATES MITIGATE THE IMPACT OF STAFF'S RECOMMENDATION?

A. No. As described above, 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.

Q. DOES GEORGIA POWER AGREE WITH DEPARTMENT OF DEFENSE WITNESS BLANK'S RECOMMENDATION TO MODIFY THE CBL REDUCTION CRITERIA?

A. No. CBLs may be reduced when load originally represented in the CBL has been permanently removed. Mr. Blank proposes to reduce CBLs when customers install generation that runs "at least 6,000 hours" (68%) of the year, even though no load has been removed. For almost one third of the year, the customer's usage on the system would be the same as it was before the installation of the generation. Generation does not

permanently remove load, and therefore does not justify the reduction of the customer's CBL.

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. 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 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. 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 the premature revision of the CBL.

Q. DOES THE COMPANY AGREE WITH WITNESS BLANK'S RECOMMENDATION TO ALLOW RTP CUSTOMERS TO ALSO TAKE SERVICE ON THE BACKUP ("BU") TARIFF?

A. No. The purpose of the BU tariff is to enable customers who are not currently receiving hourly marginal pricing to avoid yearly demand ratcheting, if their generation operates as expected. Customers may receive this benefit *or* they may benefit from marginal pricing, but not both.

Q. DOES THIS MEAN RTP CUSTOMERS ARE NOT ABLE TO BENEFIT FROM INSTALLING GENERATION?

A. No. RTP customers that install and use generation receive the benefit of the Company's marginal price for that hour. 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.

Q. DOES THE COMPANY SUPPORT MODIFYING THE TERMS AND CONDITIONS OF THE FIXED PRICE ALTERNATIVE ("FPA") RATE AND PRICE PROTECTION PRODUCT ("PPP") OFFERING TO REMOVE COMPANY DISCRETION REGARDING WHEN TO OFFER THESE RATES?

A. No. 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.

Q. DOES GEORGIA POWER SUPPORT MARTA'S REQUEST TO NOT APPLY ANY INCREASES TO THE ELECTRIC TRANSPORTATION ("ET") RATE?

A. No. Georgia Power does not support MARTA's request because it would result in a revenue deficiency being spread to other customers. Georgia Power is sympathetic to MARTA's ridership challenges during the pandemic; however, these challenges are not unique to MARTA and many other businesses have dealt with similar challenges.

IV. COMMUNITY SOLAR AND CHARGE IT ELECTRIC VEHICLE TARIFFS

Community Solar

Q. WHAT IS THE PURPOSE OF THE COMMUNITY SOLAR TARIFF?

A. The Community Solar tariff is a program that 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. 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. Additionally, the equivalent renewable energy credits ("RECs") are retired on the customer's behalf. As noted in this Commission's 2017 Order approving the program, 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 Company currently operates three Community Solar facilities located near Athens, Augusta, and Savannah.

Q. ARE GUARANTEED BILL SAVINGS PART OF THIS PROGRAM?

A. No. The Company does not guarantee or advertise the Community Solar program as a bill savings opportunity. In some months throughout the year, the credit that participating customers receive on their bill based on the solar facility's production may exceed the charge to participate, resulting in bill savings. However, as noted above, the purpose of the program is to support renewable energy and the development of solar power in Georgia and not to achieve bill savings.

Q. WHAT DID THE COMMISSION APPROVE IN THE 2022 INTEGRATED RESOURCE PLAN REGARDING THE COMMUNITY SOLAR TARIFF?

A. The Commission approved updates to the Community Solar program to make it more accessible to customers. More specifically, the Commission approved certain changes as proposed by the Company, including the Income Qualified Community Solar Pilot. The Commission did not approve the Company's requested pricing change "to increase the residential block charge to $27.99 and to set the commercial option at $29.99/month," electing instead to reserve the pricing decision for consideration in this rate case.

Q. WHAT ARE THE PROPOSED CHANGES TO THE COMMUNITY SOLAR TARIFF THAT ARE TO BE ADDRESSED IN THIS CASE?

A. The Company proposes to update the pricing for the existing residential Community Solar Charge from $24.99 to $27.99 per one kilowatt block in order to ensure that participants are not subsidized by non-participants. 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.

Q. WHY SHOULD THE COMMISSION REJECT PIA STAFF'S AND THE COALITION'S RECOMMENDATIONS TO DECREASE THE PER KILOWATT ("KW") BLOCK PRICE FOR A COMMUNITY SOLAR SUBSCRIPTION?

A. 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. As such, the Company has requested an increase in its subscription rates for residential and commercial customers participating in Community Solar. Based on the approved structure of the Community Solar program, a reduction in the price per kW block of energy would leave costs unrecovered and, therefore, shift cost recovery to non-participants.

In addition, the Coalition bases their reduction on the misguided premise that Community Solar participants pay for rate riders like NCCR, ECCR, and fuel more than once. Customers participating on the Community Solar rate still receive and pay for service on their normal retail electric service rate and are still served from all energy resources generating into or otherwise supplying the Company's system. When a participating customer pays the subscription rate to participate in the Community Solar program, this is a voluntary premium the customer opts to pay to support the addition of solar resources in Georgia. This subscription affords the participating customer the opportunity to offset their purchase of energy from Georgia Power by the amount of energy produced at the Community Solar facilities. In turn, this energy credit offsets the purchase of delivered

energy applied to the customer's bill, including with respect to the components for ECCR, NCCR, and fuel. Therefore, savings on the riders are achieved when the participating customers' kWh usage is reduced by the Community Solar production amount.

The Company includes the rate riders as part of the calculation in setting the Community Solar monthly charge because (i) that is consistent with how the R rate works and (ii) the Company must ensure that the riders are not under recovered simply because the participating customer's bill reflects fewer kWhs as a result of the energy credit applied under the Community Solar program.

Finally, because the Community Solar participant still takes service on their normal retail rate, participation in the Community Solar tariff does not automatically excuse the customer from paying their share of NCCR, ECCR, and fuel.

Q. WHY IS IT INAPPROPRIATE TO LOCK IN A COMMUNITY SOLAR PARTICIPANT'S RATE FOR THE DURATION OF PROGRAM PARTICIPATION AS PROPOSED BY THE COALITION?

A. The Company designed program pricing to prevent cost shifting to non-participating customers. The Company's costs and revenues are constantly changing. To hold a customer's cost of participation static for the duration of their participation would lead to inappropriate cost shifting to other participating and non-participating customers.

Charge Electric Vehicle ("CIEV") Rider

Q. PLEASE DESCRIBE THE CIEV RIDER.

A. Georgia Power is supporting the rapidly expanding EV market with a rider that is tailored to provide affordably priced electric service and to encourage the growth of EVs in our state. The CIEV rider will modify how the Power & Light tariffs price commercial EV charging loads. 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.

Q. WHY IS IT INAPPROPRIATE TO OPEN THE CIEV RIDER TO EXISTING LOCATIONS AS RECOMMENDED BY SEVERAL INTERVENORS?

A. 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 type of cost shift and supports keeping the CIEV rider limited to new, separately metered premises in order to appropriately incentivize new EV charging installations without doing harm to existing customers.

V. INTERCONNECTION APPLICATION FEE

Q. PLEASE EXPLAIN WHY THE COMPANY PROPOSED AN INTERCONNECTION APPLICATION FEE IN SECTION G OF THE COMPANY'S RULES AND REGULATIONS FOR ELECTRIC SERVICE.

A. The Company proposed to introduce a one-time $200 interconnection application fee that will be required for all customers seeking to interconnect a customer generating facility to the Georgia Power system. This fee is designed to recover costs associated with supporting the safe and reliable interconnection of a customer generator to the system and will help ensure that such costs are not borne by all other customers.

Q. WOULD THE COMPANY CONSIDER MAINTAINING THE EXISTING $5/KW WITNESS TESTING FEE AS PROPOSED BY GSEIA, SEIA, AND VOTE SOLAR?

A. No. The current $5/kW witness testing fee was agreed to by settlement in 2017 as part of the application of the RCB Framework to behind the meter solar. As settled to, this fee was not implemented to fully recover the Company's cost to witness test new customer generators smaller than 250 kW let alone the administrative costs to review, process, and update the customer's account for the installation of generation at its premises. In contrast, the Company's proposed $200 one-time fee is designed to cover the application, administrative costs, impact study fees and witness testing fees (where required) for new customer generation. The cost to provide these services does not vary significantly based on the size of the facility and the Company believes a flat, one-time fee is more appropriate than the outdated $5/kW witness testing fee.

VI. HOURLY INTERVAL DATA

Q. DID THE COMPANY COMPLY WITH THE COMMISSION'S DIRECTION TO EVALUATE CUSTOMER ACCESS TO HOURLY INTERVAL DATA FOLLOWING THE 2019 RATE CASE?

A. Yes. Consistent with the Commission's direction following the 2019 rate case, Georgia Power worked with Staff to develop options for customer access to usage data and then submitted recommendations to the Commission for approval. In addition, the cost to provide additional options for access to customer usage data was directed to be deferred as a regulatory asset and recovered in a future base rate proceeding, which the Company has requested for recovery in this case.

Q. IS GEORGIA POWER REQUIRED TO PROVIDE HOURLY USAGE DATA TO ALL CUSTOMERS FREE OF CHARGE AS ASSERTED BY THE COALITION?

A. No.

Q. DO THE VAST MAJORITY OF CUSTOMERS HAVE ACCESS TO THEIR HOURLY USAGE DATA?

A. Yes. The Company made hourly usage data available to customers via My Power Usage ("MPU") in January 2022. This was the result of the hourly usage project approved by the Commission. A limited group of customers are unable to use MPU; these include customers who opt-out of an AMI meter and certain unmetered accounts. Special Service Account and RTP customers are also not eligible for daily or hourly usage via MPU because they are on more complex rates and not on AMI meters, but these customers can access hourly interval usage data, along with additional features and options, by subscribing to the Company's Energy Direct website.

Q. ARE ADDITIONAL CHANGES NEEDED TO THE PROVISION OF HOURLY INTERVAL USAGE DATA?

A. No.

VII. PROPOSED CHANGES TO THE COSS

Q. DO YOU BELIEVE THAT OTHER ALLOCATION METHODOLOGIES IN ADDITION TO THE COMPANY'S FILED 12-CP METHODOLOGY SHOULD BE CONSIDERED BY THIS COMMISSION FOR THE ALLOCATION OF THE CAPACITY COMPONENT OF THE PRODUCTION FUNCTION?

A. No. When preparing for a rate case filing, Georgia Power considers other allocation methodologies in addition to its historical preference of 12-CP. For this rate case, the Company determined that 12-CP remains the most accurate and appropriate methodology. As stated in Mr. Evans' direct testimony, the 12-CP methodology incorporates the fact that Georgia Power's system is planned and operated for the purpose of serving load requests every month of the year. Additionally, PIA Staff's proposed methodologies not only impact 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.

Q. ARE PIA STAFF'S RECOMMENDATIONS CONSISTENT WITH THEIR 2019 RECOMMENDATIONS TO CHANGE HOW THE COMPANY ALLOCATES GENERATION PLANT PRODUCTION COSTS?

A. No. Staff is recommending energy-based allocation methods in this case, which are substantially different from the "up to" 8-CP method proposed by PIA Staff in the last case. If PIA Staff's recommendation had been adopted in the last case, it would be wholly inappropriate to pivot to the other end of the spectrum so drastically in this case. Adopting PIA Staff's vacillating recommendations in the 2013 and 2019 cases, and now this current rate case, would have resulted in great swings in parity results from case-to-case. To depart from using 12-CP as an allocator for Production cost, especially without compelling evidence to do so, could cause significant and unexpected disruptions to customer bills.

Q. WOULD THE COMPANY CONSIDER MOVING TO A 4-CP OR SUMMER PEAK PRODUCTION COST ALLOCATION METHOD AS RECOMMENDED BY INTERVENORS?

A. No. 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. If one were to use a pure summer peak allocator, this 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.

Q. WHY IS THE 12-CP METHOD THE MOST APPROPRIATE WAY TO ALLOCATE THE COMPANY'S PRODUCTION COSTS?

A. 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. At the jurisdictional, class, or rate group level, 12-CP is the respective coincident demands at the time of the monthly system peaks. 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.

The Company's adoption of seasonal planning further reinforces the appropriateness of the 12-CP approach. 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. 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. Georgia Power forecasts to remain a summer peaking utility. 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.

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. Further, 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. It has proven to be a common and popular allocation technique employed in numerous retail filings before many state commissions throughout the United States. It is a straightforward methodology, has a strong cost causative relationship, and has a history of providing stable and sound results.

VIII. PARITY ADJUSTMENTS

Q. DOES THE COMPANY SUPPORT MOVEMENTS TOWARD PARITY AMONG RATE GROUPS?

A. Yes. The Company has made movements toward parity in previous rate cases based on PIA Staff's recommendation. In fact, since 2010, all of Georgia Power's rate groups have moved toward parity or maintained relative parity. While the Company supports movement towards parity, the Company does not support the parity adjustments outlined in the testimony of Mr. Pollock on behalf of GAM or the testimony of the Barber, Deitchman, Watkins panel for PIA Staff. Any adjustments toward parity should be based upon the COSS presented in Exhibit LPE-1 filed by the Company in the rate case filing. The precision of a COSS and the accuracy of the results are greatly impacted by the number of customers and the amount of load in each rate. The smaller the number of customers and the smaller the amount of load in a particular rate, the lesser the potential accuracy of the results associated with that rate. Some rates have very limited participation and may produce volatile rates of return and parity results in cost-of-service studies for different time periods. With this in mind, the Commission should consider the cost-of-service to the eight rate groups instead of by individual rates.

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing REBUTTAL TESTIMONY OF THE PANEL OF AARON P. ABRAMOVITZ, SARAH P. ADAMS, ADAM D. HOUSTON AND MICHAEL B. ROBINSON, (2) THE REBUTTAL TESTIMONY OF JAMES M. COYNE, (3) THE REBUTTAL TESTIMONY OF STEVEN M. FETTER, AND (4) THE REBUTTAL TESTIMONY OF THE PANEL OF LARRY T. LEGG AND LEE EVANS 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 18th day of November 2022.



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