DIRECT TESTIMONY OF

**DAVID P. POROCH, SARAH P. ADAMS, AND MICHAEL B. ROBINSON**

**ON BEHALF OF**

**GEORGIA POWER COMPANY**

**DOCKET NO. 42516**

1. INTRODUCTION

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

A. David P. Poroch. I am Executive Vice President, Chief Financial Officer, Treasurer, and Comptroller for Georgia Power Company (“Georgia Power” or the “Company”). My business address is 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

A. Sarah P. Adams. I am Assistant Comptroller for Georgia Power. My business address is 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

A. Michael B. Robinson. I am the Power Delivery Operations General Manager for Georgia Power. My business address is 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

**Q. MR. POROCH, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.**

A. I graduated from Northwood University in 1991 with a Bachelor of Business Administration degree in Accounting. I began my career in the audit practice of Deloitte & Touche LLP and progressed through staff, senior, manager, and senior manager positions. In 2003, I was promoted to partner. I have 22 years of experience in the utilities sector of the energy industry and additional significant experience in financial services.

In January 2012, I joined Southern Company Services as Chief Audit Executive and was promoted to Vice President in August 2012. In this role, I was responsible for overseeing the internal auditing services of Southern Company and its subsidiaries. In August 2014, I joined Georgia Power as Vice President and Comptroller. In April 2019, I assumed my current position as Executive Vice President, Chief Financial Officer, Treasurer, and Comptroller of Georgia Power. In my current position, I am responsible for the financial and accounting functions of the Company. My duties include overseeing corporate accounting in accordance with generally accepted accounting principles (“GAAP”) and various regulatory requirements and the preparation and filing of financial reports and regulatory filings, including rate cases. I also oversee budgeting, financial planning and analysis, and treasury activities of the Company. I am also a Certified Public Accountant, licensed in Michigan, Georgia, and Florida.

**Q. MR. POROCH, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION (“COMMISSION”)?**

A. Yes, I testified before this Commission regarding the Fifteenth, Sixteenth and Seventeenth Semi-Annual Vogtle Construction Monitoring (“VCM”) Reports and the Supplemental Information, Staff Review, and Opportunity for Settlement in Docket No. 29849. I also testified in the Company’s Fuel Cost Recovery proceeding in Docket No. 39638.

**Q. MS. ADAMS, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.**

A. I graduated from the University of Georgia in 1993 with a Bachelor of Science in Middle School Education and in 1998 with a Master of Accountancy degree. I began my professional accounting career with Arthur Andersen, LLP in Atlanta as an auditor primarily serving Southern Company. From 2002 to 2003 I served as senior financial analyst at Mirant Corporation. In 2003, I joined Southern Company and held several leadership positions in the Southern Company Generation and Southern Power Company organizations. In 2011, I joined Georgia Power as the manager of fuel and bulk power accounting and led several departments, including internal controls & compliance, corporate secretary support, and accounting & finance operations before being elected to my current position as Assistant Comptroller in 2017. My responsibilities include management and oversight of accounting research, preparation of financial statements in accordance with GAAP as well as regulatory accounting filings with the Commission. I am a Certified Public Accountant licensed in Georgia.

**Q. MS. ADAMS, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. No, I have not previously testified before the Commission.

**Q. MR. ROBINSON, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I graduated from Auburn University in 1993 with a Bachelor of Electrical Engineering, magna cum laude. I began my career as a cooperative education student with Georgia Power working in distribution and marketing. After leaving the Company to serve in the United States Navy, I worked for an electric municipality in Texas, the Kerrville Public Utility Board, for five years where I was responsible for all distribution and substation facilities. In 1999, I returned to Southern Company as an engineer on the Enhanced Power Quality team with Alabama Power. Throughout my career at Southern Company, I have served in a variety of positions throughout the system including: principal engineer in Transmission Planning; supervisor of the transmission maintenance center in Albany, Georgia; supervisor of the transmission control center in Valdosta, Georgia; transmission planning manager; South Georgia area transmission manager; Metro South distribution manager; and general manager of Transmission Planning and Operations.

I am currently the Power Delivery Operations General Manager for Georgia Power. I lead a team of 275 employees that consists of Georgia Power’s two distribution control centers, the Georgia Transmission Control Center, operations support, and North American Electric Reliability Corporation compliance. This team is responsible for operating 75,000 miles of distribution lines, 17,000 miles of transmission lines, and over 2,000 substations statewide.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. No, I have not previously testified before the Commission.

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

A. The purpose of our testimony is to support the Company’s filing in this docket, including the calculation of the test period revenue requirement. This Commission’s May 9, 2016 Order in Docket No. 39971, regarding the AGL Resources - Southern Company Merger (“Merger Order”), required that the Company file a general rate case by July 1, 2019, so that the Commission may consider whether to continue, modify, or discontinue the rate plan established in Georgia Power Company’s 2013 Rate Case, Docket No. 36989 (“2013 Rate Case”). In our testimony, we demonstrate that the Company’s revenues under current rates are inadequate to cover the Company’s cost of service, and we propose an Alternate Rate Plan (“ARP”) similar to the ARPs Georgia Power has had in place since 1995. Our testimony will also discuss certain transmission-related upgrades necessary should additional coal units be retired as well as the Company’s grid investment plan for transmission and distribution (“T&D”) projects over the next several years. These investments are reasonable and necessary for Georgia Power to maintain a reliable and safe T&D system.

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A.The remainder of our testimony is organized as follows:

* Section II (pages 8 to 17) provides an overview of the Company’s request and the principal factors affecting that request.
* Section III (pages 18 to 24) describes the ARP.
* Section IV (pages 24 to 26) discusses the proposed method for recovery of Coal Combustion Residuals (“CCR”) Asset Retirement Obligation (“ARO”) compliance costs.
* Section V (page 27) discusses the Environmental Compliance Cost Recovery (“ECCR”) Tariff.
* Section VI (pages 27 to 28) discusses the Demand Side Management (“DSM”) Tariffs.
* Section VII (pages 28 to 29) discusses the Municipal Franchise Fee (“MFF”) Tariff.
* Section VIII (pages 30 to 33) provides a detailed discussion of our forecasted revenue requirements for both the statutory test period and the three-year proposed ARP.
* Section IX (pages 34 to 50) provides a summary of projections for Test Period Ending July 31, 2020.
* Section X (pages 50 to 62) provides a discussion of T&D investments.
* Section XI (page 62) provides an explanation of the adjustments made related to the Company’s 2019 Integrated Resource Plan (“2019 IRP”).
* Section XII (pages 63 to 65) provides a discussion of wholesale sales.
* Section XIII (pages 65 to 66) provides a discussion of working capital requirements.

**Q. MR. POROCH AND MS. ADAMS, PLEASE SUMMARIZE THE COMPANY’S REQUEST IN THIS CASE.**

A. The Company is proposing an ARP that will provide the following:

* Provide customers with the full benefits of the 2017 Tax Cuts and Jobs Act (“Tax Reform Act”) while maintaining the Company’s financial integrity;
* Allow the Company to recover the necessary capital investments made since 2013 and investments that will be made over the next three years with updated depreciation rates;
* Reasonably amortize the substantial deferred storm damage expenses incurred since 2013 and set a reasonable level of anticipated storm damage expenses for the next three years in an effort to prevent further under recoveries;
* Allow the Company to recover the costs necessary to comply with the federal and state regulations for CCR ARO; and
* Finally, as Mr. Legg will discuss in his testimony, the Company plans to modernize our rate design to reflect the evolving nature of our business and our customers’ usage patterns.

Importantly, the requested increase is not driven by an increase in operation and maintenance (“O&M”) expenses since the 2013 Rate Case. Our projected O&M expenses included in this filing are lower than the amount approved in the 2013 Rate Case, despite inflationary pressures and increased labor and health care costs.

As Mr. Bowers discusses in his testimony, there are several factors that have increased our revenue requirement since 2013, and several factors that have offset some of those increases. As a result, a significant portion of our increased cost of serving our customers has been mitigated. Despite these mitigating factors, the current base rates established by the Commission’s final order in the Company’s 2013 Rate Case and revised through the 2015 and 2016 compliance filings (collectively the “2013 Rate Case Order”) are no longer sufficient to allow the Company to recover the costs necessary to continue providing safe and reliable retail electric service for our customers and maintaining the high levels of customer service that Georgia Power’s customers have come to expect.

**Q. ARE THERE COSTS RELATED TO PLANT VOGTLE UNITS 3 AND 4 INCLUDED IN THIS FILING?**

A. Only the Vogtle Units 3 and 4 cost components approved in the 2013 Rate Case Order are reflected in retail cost of service in this filing. In compliance with the 2013 Rate Case Order, the Company continues the adjustments for Vogtle 3 and 4 nuclear fuel and the Nuclear Construction Cost Recovery (“NCCR”) Tariff. In compliance with the VCM-17 final order, other Vogtle Units 3 and 4 costs are excluded from this filing as shown in Exhibit\_\_\_(DPP/SPA/MBR-6, Schedule 3).

**Q. MR. ROBINSON, PLEASE SUMMARIZE THE T&D INVESTMENTS YOU WILL DISCUSS IN YOUR TESTIMONY.**

A. The Company manages an extensive T&D system that has served Georgia Power customers with reliable, affordable, and safe electric service for over a century. As part of the stipulation executed between Public Interest Advocacy Staff, the Company, and certain Intervenors (collectively the “Parties”) to resolve all issues in the 2019 IRP (“2019 IRP Stipulation”), the Parties acknowledged that should the retirement of Plant Bowen Units 1 and 2 be necessary, there will be transmission issues that would need to be addressed in the 2019 base rate case. I am testifying in part to facilitate the consideration of this issue.

In addition, I will present to the Commission the Company’s overall plans to increase our investment in the T&D system for the benefit of Georgia Power customers. Georgia Power continually evaluates options for building, operating, and maintaining our network performance. The Company determined that it must increase grid investments to address two emerging issues. First, a significant portion of the Company’s transmission assets are approaching or have exceeded industry standards for expected life. Without implementing a more proactive approach, the Company will experience increased equipment failures, higher maintenance costs, and higher replacement costs. Second, the Company must invest in certain distribution feeders on the system to ensure that all customers are receiving appropriate levels of reliability.

Georgia Power has made strategic infrastructure investments that have substantially benefited customers over the past decade. Over the next several years, the Company will continue making prudent and necessary infrastructure investments required to improve reliability and service for customers. The Commission enabled a pathway for the initial investment in the Advanced Metering Infrastructure (“AMI”) project, and the Company now has more comprehensive data and analytical results that will allow us to improve the customer experience for nearly 1.1 million additional customers.

1. OVERVIEW OF THE COMPANY’S REQUEST AND THE PRINCIPAL FACTORS AFFECTING THAT REQUEST

**Q. WHAT IS THE COMPANY’S REQUESTED INCREASE IN BASE RATES?**

A. As we will explain later in our testimony, the Company is requesting a continuation of the ARP with two step increases during the three-year term of the ARP. The primary drivers of the increase will be discussed later in our testimony, however, key components include the continued investment in the production, transmission and delivery of clean, safe, reliable electricity to our customers; the need to amortize and recover the deferred storm damage costs including four major storms since 2013; the need to update our depreciation and amortization expenses to account for current conditions; and the need to address incremental CCR ARO compliance costs that the Company is incurring to comply with state and federal regulations. There are some offsetting factors that are also discussed later in our testimony, such as Tax Reform Act savings and reductions in O&M expenses. As shown below in Table 1, the Company requests increases of $563 million, $145 million, and $234 million to be effective January 1, 2020, January 1, 2021 and January 1, 2022, respectively.

**Table 1: Proposed Rate Adjustments (in millions)**

|  |  |  |  |
| --- | --- | --- | --- |
| Effective Date | **January 1, 2020** | **January 1, 2021** | **January 1, 2022** |
| Traditional Base: |  |  |  |
| Levelized (a) | $209 | $0 | $0 |
| CCR ARO (b) | 158 | 140 | 227 |
| ECCR (c) | 165 | 0 | 0 |
| DSM\* (d) | 14 | 2 | 1 |
| MFF (e) | 17 | 3 | 5 |
| **Total ($)** | **$563** | **$145** | **$234** |

\*As determined by the Commission through annual DSM filings.

Note: Amounts may not sum to total due to rounding.

*See the following exhibits supporting Table 1:*

(a) Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 2 Traditional Base) Page 1

(b) Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 2 Traditional Base) Page 4

(c) Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 3 ECCR) Page 1

(d) Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 4 DSM) Page 1

(e) Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 5 MFF) Page 1

The proposed rate adjustment includes a levelized increase of $209 million of traditional base and a levelized increase of $165 million for the ECCR tariff effective January 1, 2020. Except for adjustments to traditional base tariffs required in the VCM-17 final order, this levelized increase of $374 million will not change through December 31, 2022.

In each of the three years 2020 through 2022, the Company requests recovery of CCR ARO compliance costs through annual increases in traditional base tariffs.

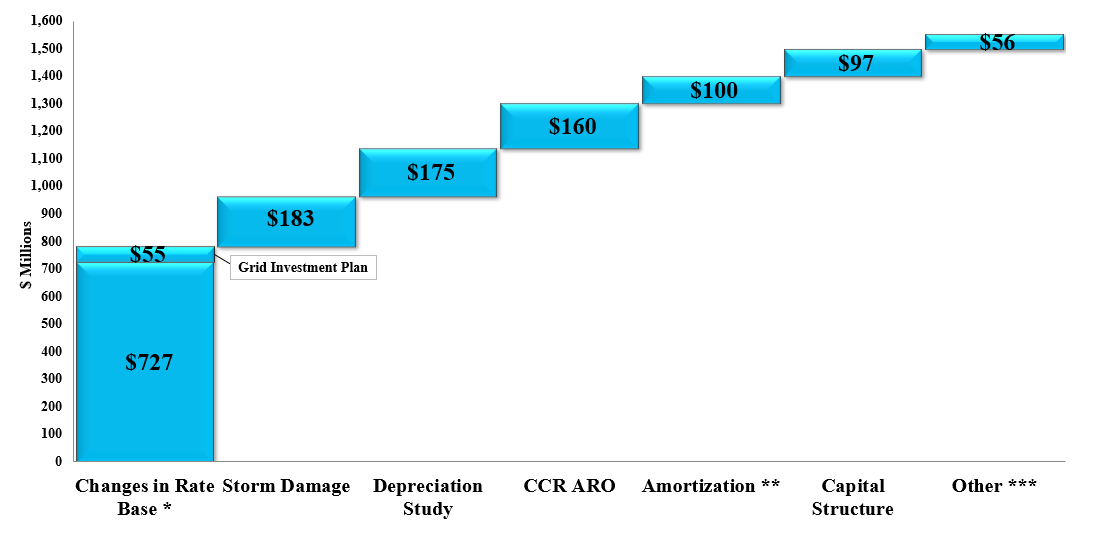
The DSM tariffs will be adjusted annually to collect the Commission-approved DSM costs addressed in Georgia Power’s DSM certification proceeding in Docket No. 42311 (“2019 DSM Certification”). The Company will also continue the true-up of actual revenues collected and expenses incurred under the DSM tariffs through the annual compliance filings. Therefore, the proposed DSM tariffs do not include levelization over the three-year period.

Accordingly, the MFF tariff will be adjusted to capture the increase in the tariffs discussed above and updated to incorporate the change in percentage of revenues from inside the municipalities. The MFF tariff may be modified during the term of the proposed ARP to account for new incorporation of municipalities, as provided in the current MFF tariff. The changes in the CCR ARO compliance cost collections and the DSM collections will have a corresponding effect on the MFF tariffs in 2021 and 2022.

Combined, the Company’s 2020 requested increase totals $563 million, a change of 7.22% to the Company’s retail rates that will result in an increase of approximately $9.78 to the monthly bill of a typical residential customer using an average of 1,000 kWh per month. The proposed 2021 and 2022 annual traditional base rate increases for projected incremental CCR ARO compliance costs of $140 million and $227 million, combined with expected increases for DSM and MFF tariffs, will result in increases of 1.75% and 2.74% of retail rates, and approximately $2.56 and $4.14 to the monthly bill of a typical residential customer using an average of 1,000 kWh per month.

**Q. PLEASE EXPLAIN THE REASONS FOR THE INCREASE IN THE COMPANY’S PROJECTED REVENUE REQUIREMENT SINCE CURRENT BASE RATES WERE ESTABLISHED IN THE 2013 RATE CASE.**

A. Over the last six years the Company has made significant investments for the benefit of customers and incurred substantial and unexpected storm restoration costs, which have been deferred as provided by prior Commission Orders. In addition, we need to continue to comply with environmental regulations and make capital investments to serve our customers. The chart below helps illustrate the principal cost drivers since 2013.

**Chart 1: Review of Increasing Drivers**

*\* Changes in Rate Base include changes in depreciation and property taxes*

*\*\* Amortization includes Stewart County, obsolete inventory and Mitchell 3, Hammond, McIntosh, Hydro NBV*

*\*\*\* Other includes MFF, cost of debt, other revenues, etc.*

The largest factor contributing to our increased costs since the 2013 Rate Case, is the fact that since 2013 and accounting for adjustments in the 2015 and 2016 compliance filings, the Company’s net retail rate base has increased by approximately $1 billion through 2018 on a 13-month average basis and is expected to further increase an additional $4.8 billion through 2022. The increases for prior and future rate base are primarily driven by continued investment in the production, transmission and delivery of clean, safe, and reliable electricity to our customers offset by deferred tax liabilities and accumulated depreciation. The annual revenue requirement caused by these investments, including the associated depreciation and property taxes, is included in the first column.

The next largest factor is the need to amortize and recover the deferred $449 million balance in storm damage costs including four major storms since 2013. We propose to amortize that amount over three years ($150 million annually) and also set a new level of projected storm accrual at $64 million annually to better reflect anticipated costs of future storms.

The third major cost driver is the need to update our depreciation expenses to account for current conditions. For example, the depreciation rates set in the 2013 Rate Case Order must be adjusted to reflect updated estimates for service lives and removal costs.

Another major cost driver is the need to address incremental CCR ARO compliance costs that the Company is incurring to comply with state and federal regulations. The Company’s proposed plan for addressing these, as well as other environmental compliance costs, was included in the Company’s Environmental Compliance Strategy (“ECS”) in the 2019 IRP. The Company’s proposed methodology for recovering these costs is described in more detail later in the testimony.

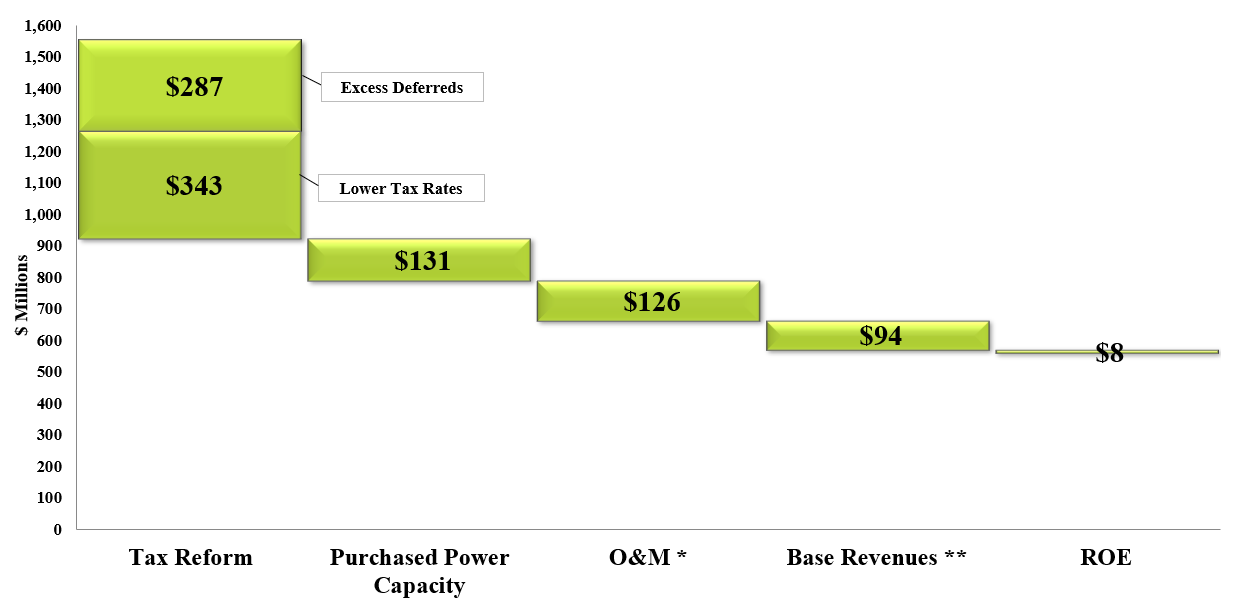
The Company is also proposing reasonable periods for amortization of certain regulatory assets previously approved by the Commission and those contained in the 2019 IRP Stipulation such as obsolete inventory of decertified plants, future nuclear costs, and the remaining net book values of certain retired plants. The case, as filed, will seek to fully amortize these regulatory assets in a timely manner consistent with the three-year rate order under the proposed ARP, except for the net book value of Plant Hammond Units 1-4, which we have proposed to amortize over the remaining useful lives of the units as approved in the 2013 Rate Case Order.

While the Tax Reform Act provided sizable benefits to our customers, it also adversely affected the Company’s credit metrics requiring a change in equity ratio. As will be explained in more detail later in this testimony as well as in the testimonies of Dr. Vander Weide and Mr. Fetter, the capital structure and associated return on equity (“ROE”) proposed in this case are critical to maintaining our credit ratings. If our credit ratings are lowered, costs will increase for all customers.

**Q. HAVE SOME FACTORS HELPED MITIGATE THE REVENUE REQUIREMENT INCREASE?**

A. Yes. The chart below helps illustrate the factors which have mitigated the increases in our costs since 2013:

**Chart 2: Review of Decreasing Drivers**

*\* O&M includes environmental remediation*

*\*\* Base Revenues include DSM under-recovery*

By far, the factor having the largest downward impact on our revenue requirement is the customer benefits from the Tax Reform Act which reduced the corporate federal income tax rate from 35% to 21%. To date, customers have received approximately $225 million through refunds provided in October 2018 and June 2019 and will receive additional refunds of approximately $105 million in February 2020. This translates to approximately $70 in refunds for the typical residential customer. In total, the Tax Reform Act will provide almost $2.5 billion of tax benefits to Georgia Power customers through 2022.  As a result, the Company is requesting substantially lower rates than would have otherwise been required beginning in 2020.

During the consideration of the Tax Reform Act by the Commission, the Company explained that the reduction to federal and state income tax rates have a corresponding and significant impact on the Company’s credit metrics if they are not addressed by a modest increase in the equity ratio component of the Company’s capital structure. This adjustment to the Company’s capital structure is needed to ensure that the Company maintains the ability to readily access the capital markets at favorable rates. Without the Commission’s decision to adopt the Tax Reform Act Settlement in Docket No. 36989 (“Tax Reform Act Settlement”), there would have been a reduction in the funds from operations (“FFO”). The reduction in FFO is driven by a combination of reduced deferred taxes held as a result of lower tax rates, lower revenue requirements due to the amortization of excess deferred tax benefits, and slower tax depreciation for future capital investments in the absence of bonus depreciation. A decrease in cash flows will weaken credit metrics and increase financial pressures on the Company to the detriment of customers.

A strong capital structure is critical to the financial health and stability of the Company. As discussed by Mr. Fetter, the FFO-to-debt ratio is a critical credit metric for utilities. In the Commission’s Order on the Tax Reform Act, the Commission increased the Company’s allowed equity component in the capital structure which correctly recognized the adverse effects the Tax Reform Act would have on the Company’s key credit rating metrics. Similarly, in this case, the Commission should adopt the recommendation of Dr. Vander Weide on the ROE and the resulting capital structure to ensure that the Company can continue to access capital markets at reasonable rates and terms.

Another significant factor putting downward pressure on our revenue requirements is the decrease in power purchase agreement (“PPA”) expenses primarily driven by the expiration of two PPAs. This will save the Company and our customers approximately $131 million annually.

Despite inflationary pressures and increased labor and health care costs, we have worked hard to manage the Company’s O&M expenses. In fact, our projected O&M expenses, with the exception of Commission-approved accruals for storm restoration, are now approximately $126 million lower than the levels set in the 2013 Rate Case Order. In an effort to address our customers’ changing expectations and to reduce costs, the Company implemented various cost-containment and business restructuring efforts. We have implemented several payment initiatives designed to improve customer satisfaction and reduce bad debt expense; consolidated various functions across the Company to reduce headcount and better align priorities and strategies; and closed all of the Company’s local bill payment offices.

In regard to base revenues, on a weather-normalized basis, retail base revenues are lower than what was projected in the 2013 Rate Case. Although pre-recession organic sales growth has not materialized, our current modest sales growth expectations that are generated by new customers still contribute to lowering the revenue requirement by approximately $94 million.

Another factor reducing our revenue requirements is our recognition that the Company’s ROE can be reduced from 10.95% set in the 2013 Rate Case Order to 10.90% for the next three years to reflect modest changes in the economic environment. Dr. Vander Weide will further explain the basis for the recommended ROE in his testimony.

**Q. IN SUMMARY, SHOW THE PRIMARY DRIVERS OF THE COMPANY’S PROPOSED LEVELIZED AND ANNUAL INCREASES.**

A. Chart 3 below depicts the factors we have just discussed that are increasing and offsetting revenue requirements along with the resulting revenue deficiency.

**Chart 3: Review of Drivers 2014-2022**



*\*Changes in Rate Base include changes in depreciation and property taxes*

*\*\*Amortization includes Stewart County, obsolete inventory and Mitchell 3, Hammond, McIntosh, Hydro NBV*

*\*\*\* Other includes MFF, cost of debt, other revenues, etc.; O&M includes environmental remediation; Base Revenues include DSM under-recovery*

**Q. DID THE COMPANY CONSIDER ONE-YEAR RATE INCREASES FOR EACH OF THE THREE YEARS IN THIS CASE?**

A.Yes. After considering all of the factors identified above, if we were to propose three consecutive one-year rate increases using a traditional annual rate case structure, or a three-year accounting order that adjusted rates on a non-levelized basis, the Company projects that the revenue deficiencies will be as follows:

**Table 2: Projected Revenue Requirement Deficiency by Year (in millions)**

|  |  |  |  |
| --- | --- | --- | --- |
|  | **2020** | **2021** | **2022** |
| Traditional Base: |  |  |  |
| Not Levelized (a) | ($4) | $230 | $434 |
| CCR ARO (b) | 158 | 298 | 525 |
| ECCR (c) | 184 | 167 | 141 |
| DSM\* (d) | 14 | 16 | 17 |
| MFF | 12 | 21 | 30 |
| **Total ($)** | **$364** | **$732** | **$1,147** |

\*As determined by the Commission through annual DSM filings.

*See the following for exhibits supporting Table 2:*

(a) Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 2 Traditional Base) Page 3

(b) Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 2 Traditional Base) Page 4

(c) Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 3 ECCR) Page 3

(d) Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 4 DSM) Page 1

As Table 2 illustrates, the Company’s projected revenue requirement in 2020 is lower, but the 2021 and 2022 revenue requirements are higher than the levelized revenue requirement over the three-year period. Of course, using an annual rate case structure, the projected costs can change and the ultimate amount of rate change from year to year creates uncertainty for our customers.

Rather than annual rate increases to address the total revenue requirement, and their uncertain outcomes for both the Company and our customers, we propose continuing the three-year ARP with its rate certainty and protections for customers through the existing earnings sharing mechanism. As Table 2 above clearly illustrates, even with the factors offsetting the increase to revenue requirements, the Company still has a revenue deficiency in each year 2020 through 2022.

III. THE PROPOSED ALTERNATE RATE PLAN

**Q. HOW DOES THE COMPANY PROPOSE TO COLLECT THE REVENUE REQUIREMENT UNDER ITS PROPOSED THREE-YEAR (2020 – 2022) ARP?**

A. The Company proposes to continue with the existing ARP structure which is outlined as follows:

* Continuation of traditional base rate tariffs through December 31, 2022 with adjustments necessary to collect the three-year revenue requirements effective January 1, 2020. The tariff adjustments will reflect currently-projected revenues, expenses, rate base growth and cost of capital that includes a fair and reasonable ROE, based on a test year ending July 31, 2020, with a modification for an appropriate levelization adjustment for all items except the CCR ARO compliance costs. The base rate tariffs will be adjusted further on January 1, 2021 and on January 1, 2022 to reflect the increase in the revenue requirement for CCR ARO compliance costs, as described later in our testimony;
* Continuation of the ECCR tariff through December 31, 2022, with revisions effective January 1, 2020 for currently projected revenues, expenses, rate base growth and cost of capital that includes a fair and reasonable ROE based on a test year ending July 31, 2020, with a modification for an appropriate three-year levelization adjustment;
* Adjustment of the DSM tariffs with revisions effective January 1, 2020 to recover prior period under-recovered cost, the cost of the programs, and Additional Sum to be approved by the Commission in the 2019 DSM Certification with annual filings to update the DSM tariffs to be effective January 1, 2021 and 2022;
* Adjustment of the MFF tariff with revisions effective January 1, 2020 to update the percentage of revenues inside municipalities with the option to file annual compliance filings to account for new incorporation of municipalities;
* Continuation of the current ROE range of 10.00% to 12.00%;
* Continuation of the Annual Surveillance Report (“ASR”) process with two-thirds of any earnings above the allowed ROE range dedicated to the benefit of customers and one-third retained by the Company; and
* Continuation of the option to file an Interim Cost Recovery (“ICR”) tariff in the event that earnings are projected to fall below the bottom of the range during any calendar year of the three-year term of the plan.

The ARP proposed by the Company in this case will retain many of the existing structural features, such as sharing of earnings above the ROE band, that were approved in the 2013 Rate Case Order. Importantly, this balanced approach provides stable rates for customers, smaller increases over time for CCR ARO compliance, and provides Georgia Power with timely recovery of previously incurred or increasing costs to maintain strong credit metrics.

**Q. PLEASE DESCRIBE THE ACCOUNTING FOR LEVELIZATION OF REVENUE REQUIREMENT UNDER THE PROPOSED THREE-YEAR ARP.**

A. As presented in Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 2), the Company’s projected revenue requirement for traditional base rate tariffs excluding CCR ARO compliance costs in 2020 is lower and the 2021 and 2022 revenue requirements are higher than the levelized revenue requirement over the three-year period. Therefore, with base rates requested under the levelized revenue requirement in this filing, the Company projects to over-collect in 2020 and under-collect in 2021 and 2022. To balance revenues associated with the revenue requirement for the corresponding years, the Company proposes to defer the projected over-collection of $214 million in 2020 to a regulatory liability account that will reduce rate base in 2021 and 2022 and be fully amortized at the end of 2022.

For the ECCR tariff presented in Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 3 ECCR), the Company’s projected revenue requirements in 2020 and 2021 are higher, but the 2022 revenue requirement is lower than the levelized revenue requirement over the three-year period. Therefore, the Company projects to under-collect in 2020 and 2021 and over-collect in 2022. To balance revenues associated with the revenue requirement for the corresponding years, the Company proposes to defer the projected under-collection of $21 million in 2020 and 2021 to a regulatory asset account that will increase rate base in 2021 and 2022 and be fully amortized at the end of 2022.

**Q. WHY IS THE COMPANY PROPOSING TO RECOVER THE CCR ARO COMPLIANCE COSTS THROUGH ANNUAL STEP INCREASES?**

A.Current traditional base rates include estimates for coal ash pond and certain landfill closure costs developed prior to the approval of both federal and state CCR rules in 2015 and 2016, respectively. Therefore, current rates do not include the latest estimates for CCR ARO compliance costs as presented in the Company’s 2019 IRP. To mitigate the immediate impact to customer bills, the Company proposes to recover these costs by adjusting rates on an annual basis beginning January 1, 2020. The Company understands the importance of balancing rate stability and minimizing the impact of the necessary rate increases on customers. We believe a gradual approach to increasing the recovery of CCR ARO compliance costs over time represents a balance between the value of rate stability with a one-time levelized rate adjustment and the importance of minimizing the amount of the initial rate adjustment customers will experience in 2020. We discuss our proposal for CCR ARO compliance cost recovery further in Section IV.

**Q. HOW WILL THE COMPANY’S PROPOSED ARP BENEFIT CUSTOMERS?**

A. The Company’s proposed ARP will produce several benefits for Georgia Power customers. As experience has shown over the past 23 years, our ARPs have aligned customer interests with shareholder interests in that both benefit from the Company’s focus on providing clean, safe, reliable, and affordable electricity and exceptional customer service. In an environment with frequent rate cases, utilities often have little incentive to manage and reduce costs. Conversely, customers have no opportunity to share in earnings when the utility delivers better than expected financial results.

Under the ARPs, like we have had in Georgia since 1995, customers have experienced more rate stability over each of the three-year periods. This allows customers to better plan their energy budgets.

In addition, customers and the Company both benefit from the fact that the ARP reduces regulatory lag. It allows Georgia Power to recover prudently-incurred costs to serve customers on a more-timely basis. Recovering such costs on a timely basis is a cornerstone of a constructive regulatory framework and represents a qualitative attribute considered favorably by credit rating agencies. To that end, a constructive regulatory framework and continued ability to access capital markets at competitive rates on a timely basis ultimately translates to lower costs for Georgia Power customers. Importantly, adequate capital market access is required for the Company’s overall financial stability, which allows it to maintain outstanding customer service—a hallmark of Georgia Power.

Finally, the continuation of the sharing mechanism benefits Georgia Power customers. If the Company performs better than expected, customers receive the majority (two-thirds) of any earnings above the approved ROE range under the proposed ARP. The Company’s proposal includes the same sharing mechanism previously approved by the Commission since the first ARP was approved in 1995. Absent the ARP, no obligation would exist requiring Georgia Power share any earnings with customers. When sharing has occurred through prior ARPs, customers have received the benefits through customer refunds or reduction in regulatory assets.  Since 2013, customers have benefited by approximately $160 million from this mechanism. The Company supports a continuation of this mechanism.

**Q. PLEASE DESCRIBE THE EXHIBITS SUPPORTING YOUR TESTIMONY.**

A. The exhibits supporting our testimony are as follows:

* Exhibit\_\_\_(DPP/SPA/MBR-1) consists of five schedules demonstrating and supporting the calculation of the requested revenue requirements based on a test period ending July 31, 2020, as well as calendar years 2020, 2021, and 2022.  
    
  Schedule 1 contains the calculations of the requested revenue requirements for the twelve months ending July 31, 2020 and calendar years 2020, 2021, and 2022 for the total Company excluding MFF, including projected retail rate base by components and calculation of retail operating income.

Schedule 2 contains the calculations of the requested revenue requirements for the twelve months ending July 31, 2020 and calendar years 2020, 2021, and 2022 for the traditional base tariffs. This schedule includes the calculation of the levelized revenue requirement excluding CCR ARO compliance costs as well as the annual step increases for those costs.

Schedule 3 shows the components and calculation of the requested revenue requirements related to the ECCR tariff. This schedule covers the test period ending July 31, 2020 and calendar years 2020, 2021, and 2022. This schedule also includes the calculation of the levelized revenue requirement necessary to provide stable rates over the three-year period.

Schedule 4 shows the components and calculation of the proposed revenue requirements related to the DSM tariffs. This schedule covers the test period ending July 31, 2020 and calendar years 2020, 2021, and 2022.

Schedule 5 provides the calculation and the revenue requirement impact of the MFF tariff associated with each of the base tariffs for the test period ending July 31, 2020 as well as the calendar years 2020, 2021, and 2022.

* Exhibit\_\_\_(DPP/SPA/MBR-2) is the Summary of Projections. This exhibit demonstrates the changes in revenues, expenses and rate base from the historic period, after regulatory adjustments as approved by the Commission in Docket No. 36989, and previous rate cases, for the year ended December 31, 2018, to the test period ending July 31, 2020. The exhibit also displays the adjusted retail cost of service amounts and balances for the test period ending July 31, 2020, taking into account previously approved and proposed regulatory adjustments. The exhibit provides explanations for the corresponding changes between periods, as well as the regulatory adjustments within each period.
* Exhibit\_\_\_(DPP/SPA/MBR-3) displays the details and the calculation of the 7.93% weighted average cost of capital ending July 31, 2020, including the Company’s projected capital structure and cost of debt, proposed cost of equity as supported by Dr. Vander Weide in his testimony, and a reconciliation of the budgeted balances to the adjusted balances used in calculating the retail revenue requirements. In addition, we have included the components and calculations of the 13-month weighted average cost of capital for the calendar years ending 2020, 2021, and 2022.
* Exhibit\_\_\_(DPP/SPA/MBR-4) contains various schedules that provide detailed support for amounts included in projected retail rate base included in the Company’s revenue requirement for the test period.
* Exhibit\_\_\_(DPP/SPA/MBR-5) contains various schedules that provide detailed support for amounts included in projected retail expenses included in the Company’s revenue requirement for the test period.
* Exhibit\_\_\_(DPP/SPA/MBR-6) contains various schedules that provide detailed support for amounts excluded from projected retail rate base and expenses in the Company’s revenue requirement for the test period.
* Exhibit\_\_\_(DPP/SPA/MBR-7) contains detailed information regarding the distribution investment packages.
* Exhibit\_\_\_(DPP/SPA/MBR-8) contains detailed information regarding the transmission investment packages.

IV. RECOVERY OF CCR ARO COMPLIANCE COSTS

**Q. PLEASE DESCRIBE THE CURRENT RECOVERY OF ARO COSTS.**

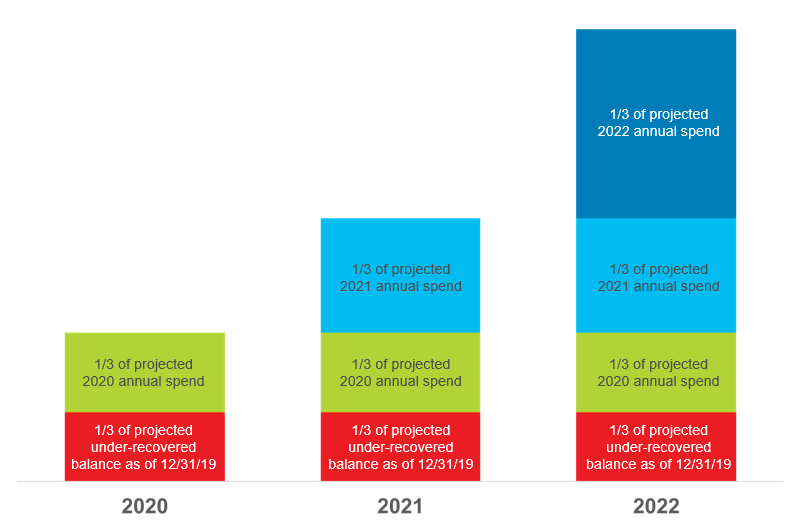
A. The Company currently recovers all ARO costs based on the annual accrual approved in the 2013 Rate Case Order. Similar to plant removal and dismantlement, ARO costs were designed to be recovered over the life of the related asset and prior to the expected date of the ARO settlements, which were generally expected to occur at the end of life of the asset. The accrued recovery of the ARO costs and actual settlements are offset and any resulting under- or over-recovery is reflected in a net regulatory liability account included in retail rate base. Except for costs associated with ash ponds and certain landfills for CCR compliance, Georgia Power proposes to continue following this methodology of accruing for ARO costs over the life of the related asset.

**Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO RECOVER CCR ARO COMPLIANCE COSTS.**

A. As provided and discussed in the Company’s 2019 IRP filing, the projected annual spend on ash ponds and landfills necessary to comply with federal and state CCR environmental regulations are currently estimated to be $277 million, $395 million, and $655 million for 2020, 2021, and 2022, respectively. In addition, the ARO regulatory balance related to CCR AROs is projected to be cumulatively under-collected by $241 million as of December 31, 2019.

To address this under-recovery, the Company proposes to recover the balance as of December 31, 2019 ratably over the three-year period ending December 31, 2022. The following chart illustrates the Company’s proposal for recovery of CCR ARO costs under the proposed ARP.

**Chart 4: Illustration of Proposed CCR ARO Recovery Method by Year**



*Chart for illustrative purposes only*

For costs projected to be incurred in 2020, the Company proposes to recover the annual spend on ash ponds and landfills ratably over the three-year period ending December 31, 2022. The projected annual spend in 2021 would be recovered in years 2021 through 2023; and the projected annual spend in 2022 would be recovered in years 2022 through 2024. Including recovery of the projected under-collected balance at December 31, 2019, projected expenditures in 2020 through 2022, and the return on the under-recovered balance, and subtracting the level of ARO accrual for ash pond compliance currently reflected in base rates, this methodology results in an annual revenue deficiency of $158 million, $298 million, and $525 million for 2020, 2021, and 2022, respectively. The Company proposes to increase traditional base rates $158 million in 2020 followed by additional annual increases to traditional base rates of $140 million and $227 million effective January 1, 2021 and 2022 respectively.

**Q. PLEASE ELABORATE ON THE COMPANY’S PROPOSED PROCESS FOR THE ANNUAL RATE ADJUSTMENTS FOR CCR ARO COMPLIANCE COSTS.**

A. Following the initial increase effective January 1, 2020, the Company proposes to submit a filing on November 1, 2020 for recovery of the projected incremental increase in CCR ARO compliance costs for 2021. The concept of a semi-annual report filing was introduced in the 2019 IRP. The 2019 IRP Stipulation requires the Company and Staff to determine the format and content of such filing. Our proposed adjustments would be based on this filing, with new rates to be effective January 1, 2021. On November 1, 2021, the Company would submit an additional filing for recovery of the projected incremental increase in CCR ARO compliance costs for 2022 with new rates to be effective January 1, 2022.

V. ENVIRONMENTAL COMPLIANCE COST RECOVERY TARIFF

**Q. WHAT RATE INCREASE IS THE COMPANY REQUESTING RELATED TO ECCR COSTS?**

A. The Company is requesting an increase of $165 million to be collected through the ECCR tariff in 2020. This amount reflects the levelization of revenue requirements designed to provide stable rates for customers over the three-year period. This revenue levelization is reflected in Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 3 ECCR), which also shows the projected required environmental investments and expenses associated with the ECCR tariff in 2020, 2021, and 2022. The costs supporting these projections are consistent with the Company’s ECS filed with and reviewed by the Commission in the Company’s 2019 IRP. The 2019 IRP Stipulation provides for the approval of the ECS.

**Q. WHAT HAPPENS TO THE ECCR TARIFF IF PROJECTED COSTS CHANGE?**

A. Consistent with the current ECCR tariff approved by the Commission in the 2016 Compliance Filing pursuant to the 2013 Rate Case Order, the projected costs to be recovered through the ECCR tariff are set based on the ECS approved in the IRP process. Any changes in projected costs will not impact the ECCR tariff rate as proposed by the Company and the ECCR tariff rate will remain stable during the term of the ARP.

VI. DEMAND SIDE MANAGEMENT TARIFFS

**Q. WHAT COSTS ARE TO BE RECOVERED BY THE COMPANY’S PROPOSED DSM TARIFFS?**

A. The Company has included an increase of $14 million, which reflects recovery of prior period under-recovered cost and the program costs and Additional Sum filed in the Company’s 2019 DSM Certification application, to be recovered through the DSM tariffs, effective January 1, 2020, as detailed on Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 4 DSM).

**Q. HOW IS THE COMPANY PROPOSING TO RECOVER REVENUE REQUIREMENTS ASSOCIATED WITH THE DSM TARIFFS?**

**A.** Consistent with the 2013 Rate Case Order, the proposed DSM tariffs will be set to collect program costs and Additional Sum approved in the Company’s 2019 DSM Certification application. The Company’s compliance filing in 2020 will reflect what is approved by the Commission in the 2019 DSM Certification docket.

VII. MUNICIPAL FRANCHISE FEE TARIFF

**Q. WHAT ARE THE TERMS OF THE CURRENT MFF TARIFF?**

A. In the Commission’s final order in Docket No. 25060 (“2007 Rate Case Order”), the Commission ordered the establishment of the MFF tariff in accordance with the Commission’s Order in Docket No. 21112. The MFF tariff reflects 50% of MFF revenues being collected from customers located within municipal areas covered by a franchise agreement and 50% being collected from all customers, regardless of location. Because the tariff is a percentage rate and is calculated based on each customer’s total bill before sales taxes are applied, the percentage rate does not have to be changed even if revenues change.

**Q. IF THE MFF TARIFF IS BASED ON PERCENTAGE RATES, WHAT COULD CAUSE THE MFF TARIFF TO CHANGE?**

A. The primary driver that could cause the MFF tariff to change from year to year is the proportion of revenues collected from customers receiving service within the municipalities’ boundaries. The MFF tariff is designed to recover the amount of franchise fees paid pursuant to our franchise agreements with the cities across our service territory. Under those agreements, the cities charge, and we pay, 4% of total revenues generated inside the respective city, which includes amounts collected from all of the tariffs: base, NCCR, ECCR, DSM, and Fuel Cost Recovery (“FCR”). Therefore, as customer demographics (proportion of electric sales revenues generated inside vs. outside municipalities) as well as customer usage patterns change from year to year, so will our franchise fee payments and so should the MFF tariff. We propose adjusting the MFF tariff annually, if needed, to align revenues with costs.

**Q. HAS THERE BEEN A SUBSTANTIAL SHIFT IN REVENUES BETWEEN CUSTOMERS RECEIVING SERVICE WITHIN MUNICIPAL BOUNDARIES AND ALL OTHER CUSTOMERS?**

A. Yes. Since the Company last updated the MFF tariff in the 2016 Compliance Filing, a number of new municipalities have been incorporated in Georgia Power’s service territory. In addition to the Macon/Bibb and Georgetown/Quitman consolidations at the end of 2014, the city of Tucker was incorporated in 2016 and the cities of South Fulton and Stonecrest were incorporated in 2018. Evidenced by the new municipalities created in the last few years, the Company expects this trend to continue in its service territory, which will increase the Company’s total franchise fee expense going forward.

**Q. HOW IS THE COMPANY PROPOSING TO RECOVER REVENUE REQUIREMENTS ASSOCIATED WITH THE MFF TARIFF?**

A. The Company is requesting approval of the $17 million increase shown on Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 5 MFF) in connection with this proceeding, to be effective January 1, 2020. The Company will continue to evaluate changes in the proportionate share of revenues collected within municipalities and, if necessary, file an update to the MFF tariff by submitting an annual filing by November 1st as provided for in the current MFF tariff.

VIII. REVENUE REQUIREMENT

**Q. WHAT PERIODS DOES THE INFORMATION IN THIS FILING COVER?**

A. The historical data in this filing is based on the Company’s actual performance for the twelve months ended December 31, 2018. The projected test period for the traditional revenue requirement is the twelve months ending July 31, 2020. In addition, the Company has provided projected data for calendar years 2020, 2021, and 2022 to meet the requirements of the 2013 Rate Case Order and the three-year continuance of the Merger Order and to support the basis for a levelized revenue requirement.

**Q. PLEASE SUMMARIZE THE RESULT OF YOUR REVENUE REQUIREMENT CALCULATIONS FOR THE TRADITIONAL TEST PERIOD ENDING JULY 31, 2020.**

A. The revenue requirement calculation in Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 1 Total Company) shows a revenue deficiency, excluding MFF, of $195 million for the period ending July 31, 2020 to be collected through the base tariffs. The jurisdictional allocations are based on an allocated cost-of-service study for the projected test period ending July 31, 2020 that Mr. Vogt will discuss in his testimony.

**Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE RETAIL REVENUE DEFICIENCY AMOUNT FOR THE TRADITIONAL TEST PERIOD ENDING JULY 31, 2020.**

A. Revenue collected from customers must cover all costs of service, including O&M expenses, taxes, depreciation, and the cost of capital, including an appropriate ROE. Retail rates must be sufficient to satisfy the interest requirements of the Company’s debt, while providing an opportunity for a fair and reasonable return on common equity invested. These cost of capital requirements are weighted by the mix of long-term debt and common equity, and reflect certain Commission rate making adjustments, to produce an overall required retail rate of return. This rate of return is then applied to the retail rate base to yield the Company’s retail earnings requirement.

The retail earnings requirement is then compared to earnings projected under the Company’s current base rates to determine the amount of retail earnings deficiency during the test period. This earnings deficiency is then adjusted to cover income taxes by using an “income expansion factor.” This factor, 74.602%, reflects a federal income tax rate of 21% and a state income tax rate of 5.75%. The income expansion factor also includes a reduction for uncollectible accounts, slightly offset by compensation for collection of sales tax. The retail earnings deficiency is then divided by the income expansion factor to determine the total revenue deficiency from retail customers, excluding MFF.

The computation of the income expansion factor is shown in Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 1 Total Company), page 2.

**Q. WHAT IS THE SOURCE OF THE PROJECTED COSTS USED IN THE FILING?**

A. The projected costs used to calculate the revenue deficiency and rate base come from the Company’s 2019 Annual Budget. The preparation of the Company’s annual budget is a cyclical process of planning, resource identification, review, revision and approval. The process involves all functional areas throughout the Company. This process results in a comprehensive financial budget, which reflects the Company’s best estimate of the resources required to provide clean, safe and reliable electric service and maintain the level of service our customers expect, while effectively managing costs.

**Q. WHAT IS THE RETAIL RATE BASE UPON WHICH THE COMPANY IS BASING ITS REVENUE DEFICIENCY FOR THE TRADITIONAL TEST PERIOD ENDING JULY 31, 2020?**

A. The projected retail rate base is $20.1 billion for the period ending July 31, 2020 as shown in the revenue deficiency calculation in Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 1 Total Company) page 1.

**Q. WHAT RATE OF RETURN IS APPLIED TO THE RETAIL RATE BASE IN THE REVENUE REQUIREMENT CALCULATION FOR THE TRADITIONAL TEST PERIOD ENDING JULY 31, 2020?**

A. The Company’s requested overall retail cost of capital is 7.93% for the period ending July 31, 2020, as determined in Exhibit\_\_\_(DPP/SPA/MBR-3, Schedule 1), which is equal to the overall cost of capital requested in the Company’s 2013 Rate Case, but slightly higher than the 7.71% that was approved.

**Q. PLEASE DESCRIBE HOW THE COMPANY’S OVERALL COST OF CAPITAL IS DETERMINED.**

A. The Company’s overall cost of capital of 7.93% is based on the 13-month average of the estimated capitalization from July 31, 2019 through July 31, 2020. The long-term debt proportion of capitalization is multiplied by its average estimated embedded cost for each month through July 31, 2020. The required return on common equity of 10.90% is described by Dr. Vander Weide in his testimony. Exhibit\_\_\_(DPP/SPA/MBR-3, Schedule 1) shows the capital structure components for the test period, together with associated costs.

**Q. HOW HAS THE COMPANY PRESENTED THE REVENUE REQUIREMENT CALCULATIONS FOR THE THREE-YEAR PERIOD IDENTIFIED IN THE PROPOSED ARP?**

A. The attached exhibits focus on the test period ending July 31, 2020, as required in the Commission’s 2013 Rate Case Order and three-year continuance provided for in the Merger Order. The Company has also filed revenue requirement information for the calendar years 2020, 2021, and 2022, consistent with the intent of the 2013 Rate Case Order and in light of the three-year continuance. This information is intended to support the Company’s requested adjustment to the test period revenue requirement for those periods. The 2020, 2021, and 2022 revenue requirements for traditional base rates including incremental ARO costs related to CCR compliance, the ECCR tariff, and the DSM tariffs are shown separately in Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 2 Traditional Base), Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 3 ECCR), and Exhibit\_\_\_(DPP/SPA/MBR-1, Schedule 4, DSM), respectively.

**Q. WHY IS THE COMPANY CHOOSING TO BASE THE REVENUE REQUIREMENT, EXCLUDING THE INCREMENTAL ARO COST FOR CCR COMPLIANCE, ON A TEST PERIOD ENDING JULY 31, 2020 WITH A LEVELIZED ADJUSTMENT FOR CALENDAR YEARS 2020, 2021, AND 2022?**

A. There are two primary reasons the Company has chosen to present the requested revenue requirement based on a test period ending July 31, 2020 with a levelized adjustment for calendar years 2020, 2021, and 2022. First, the test period ending July 31, 2020 only partially recognizes the increase in rate base and expenses that the Company will incur in the first full year following an approved increase in rates. By presenting an adjusted revenue requirement for the entire period ending December 31, 2020, the Company is demonstrating the first full year revenue deficiency, which mitigates the amount of time between incurring the cost and recovering the cost (regulatory lag). Second, by using the three calendar years ending December 31, 2022, the Company reflects the annual revenue deficiencies used in determining a levelized revenue requirement in order to provide more stable base rates during the three-year period.

IX. SUMMARY OF PROJECTIONS FOR TEST PERIOD ENDING JULY 31, 2020

**Q. PLEASE DESCRIBE THE RATE MAKING ADJUSTMENTS PREVIOUSLY ALLOWED OR REQUIRED BY THE COMMISSION THAT ARE REFLECTED IN THE COMPANY’S REQUESTED REVENUE REQUIREMENTS.**

A. The Company has made the following adjustments as reflected in Exhibit\_\_\_(DPP/SPA/MBR-2):

1. Pursuant to the Commission’s Order in Docket No. 3270, the corporate headquarters lease was reflected as an operating lease rather than as a capital lease.
2. Pursuant to the Commission’s Order in Docket No. 3840, institutional and goodwill advertising expenses have been removed from retail expenses.
3. Pursuant to the Commission’s Order in Docket No. 3840, 75% of economy energy profits were returned to retail customers through the fuel clause with 25% retained by the Company.
4. Pursuant to the Commission’s Order in Docket No. 18300, 80% of profits from short-term capacity sales were returned to retail customers with 20% retained by the Company.
5. Pursuant to the Commission’s Order in Docket No. 3673, expenses associated with the Nuclear Energy Institute have been excluded from retail expenses.
6. Wholesale revenues and expenses associated with non-territorial power marketing transactions have been removed from retail income.
7. Pursuant to the Commission’s Orders in Docket Nos. 4900, 22528, 25036, 37854, and 40161, the approved Additional Sum has been added to expenses for certain PPAs.
8. The carrying charge on over or under-recovered fuel costs added to revenues has been removed since they are credited to customers through the fuel clause.
9. Pursuant to the Commission’s Order in Docket No. 3936, revenues and costs associated with Unregulated Outdoor Lighting have been removed from retail operations.
10. The revenues and expenses related to Municipal Franchise Fees have been removed as the tariff is calculated separately from retail revenue requirement.
11. Accumulated Deferred Income Taxes (“ADIT”) related to Construction Work In Progress (“CWIP”) have been removed.
12. Income tax expense has been adjusted to reflect, as a tax deduction, only the interest expenses applicable to the retail rate base.
13. The reserve held by the external trustee for nuclear decommissioning has been removed from the ARO regulatory liability balance.
14. Pursuant to Commission’s Order in Docket No. 3397, nuclear fuel stock related to Plant Vogtle Units 3 and 4 has been removed from retail rate base and recorded as Allowance for Funds Used During Construction on the related balance.
15. Pursuant to the Merger Order, retail expenses have been adjusted to reflect 40% of the Merger Savings related to Southern Company’s acquisition of AGL Resources (now known as Southern Company Gas) to be retained by Georgia Power.
16. Nuclear Construction Cost Recovery tariff revenues and associated rate base items have been removed.
17. DSM Additional Sum has been added to expenses and the carrying charge on over- or under-recovered DSM tariffs to revenues has been removed since they are credited to customers through that tariff. The ADITs associated with the DSM over/under-recovery have also been removed.
18. Pursuant to the Commission’s Order in Docket No. 25060, any shoreline maintenance costs in excess of licensing fees collected from lake lot lessees in association with Federal Energy Regulatory Commission (“FERC”) Boundary Land has been removed.
19. Pursuant to the Commission’s Order in Docket No. 25322, 50% of profits from Co-Location Wireless Equipment programs were returned to retail customers with 50% retained by the Company.
20. Pursuant to the Commission’s Order in Docket No. 26550, the market differential adjustment was applied to retail revenues relating to certain wholesale assets transferred to retail rate base.
21. The interest portion of the capacity payments associated with the West Georgia and Dahlberg capital lease PPAs was removed.
22. The cumulative impact of these regulatory adjustments has been reflected on cash working capital

All of these adjustments are consistent with the treatment reflected in the Company’s previously filed Annual Surveillance Reports.

**Q. WHY ARE EXPENSES RELATED TO STOCK-BASED COMPENSATION APPROPRIATE FOR RETAIL COST RECOVERY?**

A. Stock-based compensation, similar to cash compensation, is part of the Company’s total compensation offered in order to attract and retain high-performing employees. It is common practice for companies to include a long-term, at-risk component such as stock-based compensation in the total compensation for employees that have greater responsibility for decisions that impact the long-term performance of the company. This form of at-risk compensation is not additional compensation. It is part of the employee’s market pay and put at risk to align employee behaviors with customer interests. Stock-based compensation, as part of a comprehensive compensation plan, allows the Company to remain competitive with the market for employees and incents the balance of long-term and short-term goals, both which, in turn, enable the Company to provide its customers with high satisfaction and reliability by allowing the Company to operate its business efficiently and effectively.

**Q. WHAT OTHER ADJUSTMENTS ARE INCLUDED IN THE COMPANY’S FILING THAT HAVE BEEN INCLUDED IN PREVIOUS CASES?**

A. The Company is proposing the following adjustments that reflect prior Commission orders:

1. Depreciation expense to reflect new depreciation rates
2. Nuclear Decommissioning expense
3. Storm Damage expense
4. Environmental Remediation expense
5. Staff consultant fees paid by the Company
6. Proration of federal ADITs
7. Test Period Normalization items

**Q. HOW HAVE THE NEW DEPRECIATION RATES BEEN REFLECTED IN THE TRADITIONAL REVENUE REQUIREMENT FOR THE PERIOD ENDING JULY 31, 2020?**

A. The depreciation rates used by the Company are reviewed in every base rate case to ensure that they continue to reflect the current cost of providing service to our customers. Our latest depreciation study shows that current depreciation rates, which were approved in the 2013 Rate Case, need to be changed to reflect updated estimates of generating unit retirement dates, decommissioning costs, and to recognize the additional investment in new facilities and retirements since the previous depreciation study. Based on the new study, the proposed revenue requirement in this filing reflects the new depreciation rates. Please refer to Exhibit\_\_\_(DPP/SPA/MBR-5, Schedule 1) and the depreciation study, which can be found in Appendix\_\_\_Exhibit 2 of this filing.

**Q. WHO PREPARED THE NEW DEPRECIATION STUDY AND ON WHAT PRINCIPLES IS IT BASED?**

A. The depreciation study was developed by Alliance Consulting Group. In addition, Southern Company Services and Brandenburg, a national demolition firm, updated the dismantlement study through 2017, which was used by Alliance Consulting Group for certain assumptions in their study. The key principles reflected in the rates are the average life group procedure, the remaining life technique, and the traditional net salvage approach. The current depreciation study is consistent with the general principles and processes followed in the 2013 Rate Case.

**Q. HAS THE COMPANY INCLUDED AN ADJUSTMENT FOR FUNDING NUCLEAR DECOMMISSIONING?**

A. Yes. The Company has updated funding amounts in the budget for the nuclear decommissioning trust accounts to reflect the treatment approved by this Commission since 2001. External trust fund balances were updated as of December 31, 2018 to calculate the projected fund contributions until decommissioning. Accordingly, we have decreased the annual nuclear decommissioning expense from $5.4 million to $4.3 million in this filing.

The proposed level of nuclear decommissioning funding is currently expected to meet Nuclear Regulatory Commission minimum funding requirements for decommissioning structures and equipment and also provides funding for the storage and eventual removal of spent nuclear fuel. Consistent with the Commission’s previous orders, the Company also excluded any costs related to site restoration of the facilities. As required by the Commission, the amounts collected will continue to be placed in an external trust fund. Information supporting the funding requirement calculation can be found in Exhibit\_\_\_(DPP/SPA/MBR-5, Schedule 4).

**Q. PLEASE DESCRIBE THE CHANGE IN THE STORM DAMAGE REGULATORY ASSET BALANCE SINCE THE 2013 RATE CASE.**

A. The storm damage regulatory asset balance has increased from $37.1 million as of December 31, 2013 to $415.8 million as of December 31, 2018. Since the Commission approved the annual storm damage expense of $29.9 million in the 2013 Rate Case, there have been a number of significant storms that impacted the Georgia Power service territory. Most notably, costs charged to the storm reserve account for Ice Storm Pax (2014) of approximately $75 million; Hurricanes Matthew (2016) and Irma (2017) totaling approximately $240 million; and Hurricane Michael in 2018, of approximately $130 million; each caused extensive damage to Georgia Power’s T&D systems at significant cost to restore power to our customers as timely and safely as possible.

**Q. PLEASE EXPLAIN THE CHANGE IN STORM DAMAGE EXPENSE AS INCLUDED IN THE BUDGET.**

A. As stated above, the Commission set the amount of annual storm damage expense at $29.9 million in 2013 Rate Case Order, which consisted of $22.8 million for projected annual storm costs and $7.1 million for recovery of prior storm costs. Although the Company projected annual storm costs based on a five-year historical average in previous base rate cases, Georgia Power has experienced a significant increase in the amount of storm restoration costs resulting from some very severe weather events in the last five years. Therefore, the Company used a 10-year historical average to project annual storm costs in this filing. As a result, the Company projects annual storm costs of $63.5 million. The regulatory asset balance for storm damage is estimated to increase to $449.4 million as of December 31, 2019. The proposed storm damage expense is set at a level expected to cover the projected increase in annual storm restoration costs estimated over the next three years, but also reimburse the Company for unrecovered storm costs already incurred since the 2013 Rate Case over the next three years. The annual storm damage expense included in the filing is $213.3 million, or an annual increase of $183.4 million. This increase reflects the Company’s request to reduce the current and projected regulatory asset balance for storm damage to zero and also accounts for an increase of $40.8 million for projected annual storm costs. The methodology used to develop the projected annual storm damage expense is shown in Exhibit\_\_\_(DPP/SPA/MBR-5, Schedule 2).

**Q. PLEASE EXPLAIN THE CHANGE IN ENVIRONMENTAL REMEDIATION EXPENSE AS INCLUDED IN THE BUDGET.**

A. The environmental remediation regulatory balance has increased from a net regulatory liability of $6.1 million as of December 31, 2013 to a net regulatory asset of $33.7 million as of December 31, 2018 and is projected to be net regulatory asset of $42.3 million at December 31, 2019. The Commission set the amount of annual environmental remediation expense at $2.3 million in the 2013 Rate Case Order. The annual environmental remediation expense included in the filing is $14.4 million, or an annual increase of $12.1 million. This increase reflects the Company’s request to recover the projected net regulatory asset balance for environmental remediation over the proposed three-year rate period. This is partially offset by a decrease of $2.8 million in the projected annual environmental remediation costs. The methodology used to develop the annual accrual is the same as approved by the Commission in previous cases and is shown in Exhibit\_\_\_(DPP/SPA/MBR-5, Schedule 3).

**Q. PLEASE EXPLAIN THE ADJUSTMENT FOR THE FEES PAID BY THE COMPANY FOR CONSULTANTS RETAINED BY THE COMMISSION STAFF.**

A. Based on O.C.G.A. § 46-2-33(a) and the May 28, 2019 Commission Order, the Company is required to provide up to $708,000 per case per year toward fees for reasonably necessary specialized testimony and assistance in certain proceedings initiated by the Company, with escalation provided on an annual basis based on the Consumer Price Index (CPI). This adjustment reflects the Company’s projection of such costs not included in the Company’s budget.

**Q. PLEASE EXPLAIN THE ADJUSTMENT FOR THE PRORATION OF FEDERAL ADITS.**

A. The Company’s calculations to determine federal ADITs conforms with Internal Revenue Code Section 167(*l*), which requires the federal ADITs provided under its normalization rules to be prorated or weighted by the number of days in each month instead of a 13-month average, when included in the revenue requirement for setting rates.

**Q. PLEASE EXPLAIN THE TEST PERIOD NORMALIZATION ADJUSTMENTS IN THE FILING.**

A. These adjustments provide for certain revenues and expenses to be normalized in the test period to align the revenue requirement impact of those adjustments and the effective date of the proposed base rates. Therefore, customers are not charged for costs or credited for revenues that are included in the test period but are eliminated effective January 1, 2020; and likewise, the adjustments include revenues or costs that begin January 1, 2020 and should be included for the full year in the test period revenue requirement. These normalization items primarily consist of changes in expenses such as changes in depreciation rates and recovery of AROs, and new amortization of regulatory assets or liabilities such as those related to tax reform and obsolete inventory at retired plants.

These adjustments are consistent with the Commission’s prior precedent and in accordance with general ratemaking principles. All of the costs were incurred in order to provide service to customers and under the approval of the Commission.

**Q. WHAT NEW ADJUSTMENTS OR ACCOUNTING ITEMS ARE INCLUDED IN THE FILING THAT HAVE NOT BEEN INCLUDED IN PREVIOUS CASES?**

A. The Company has included the following adjustments:

1. Excess ADITs and Deferred Tax Savings resulting from the Tax Reform Act

2. Amortization of Future Nuclear costs

3. Amortization of Obsolete Inventory of Decertified Plants

4. Amortization of Net Book Value (“NBV”) of Plant Mitchell Unit 3

5. Accounting for Software Costs

6. Recovery of Electric Transportation Costs

7. Gains and Losses on Disposition of Utility Land

**Q. PLEASE DESCRIBE THE IMPACTS OF THE TAX CUTS AND JOBS ACT AND THE COMMISSION APPROVAL OF THE TAX REFORM ACT SETTLEMENT.**

A. In December 2017, the Tax Reform Act was signed into law which lowered the federal corporate income tax rate from 35% to 21%, effective January 1, 2018. In March 2018, the Company and Commission Staff executed the Tax Reform Act Settlement, which addressed the impacts of the Tax Reform Act on retail cost of service. The settlement was subsequently approved by the Commission. Following the change in federal income tax rate, the state income tax rate was also changed from 6.00% to 5.75%, effective January 1, 2019, for seven years through 2025. The Tax Reform Act Settlement provides significant savings for customers both short-term and long-term while addressing the Company’s need to mitigate the negative impact of the legislation on the Company’s credit metrics.

Specifically, the Tax Reform Act Settlement provides retail customers:

* Refunds of $330 million of revenue collected in 2018 and 2019 for reduction in federal income tax rates effective in 2018 and 2019;
* The deferral of all retail federal unprotected and protected excess ADITs to be considered in this case; and
* The deferral of all retail state excess ADITs and tax savings as a result of the reduction in state income tax rates to be considered in this case.

Although the legislation provides income tax savings to the Company, and therefore to customers, it has a negative impact to the Company’s cash flow metrics because it eliminates bonus depreciation tax deduction on future capital assets and lowers the level of deferrable income taxes going forward. To partially mitigate this impact, the Commission allowed the Company to increase its common equity ratio to the lower of the actual common equity structure or 55%.

**Q. WHAT IS THE IMPACT OF TAX REFORM ON THE COMPANY’S REVENUE REQUIREMENT IN THIS FILING?**

A. The Company’s revenue requirements for the test period and calendar years 2020 through 2022 reflect the lower federal and state income tax rates in these income tax calculations, resulting in a lower income tax requirement for customers. In addition, as it relates to the unprotected ADITs and state tax savings in 2018 and 2019 deferred for consideration in this case, the Company is proposing to amortize these items, representing approximately $670 million, for the benefit of customers over the three years covered by this ARP. Protected ADITs related to tax depreciation are included in rate base using the average rate assumption method (“ARAM”) as required by the Internal Revenue Service normalization rules in order to continue giving customers the significant tax benefits of accelerated depreciation.

For federal protected excess ADITs, the amortization is also required to follow ARAM under the Internal Revenue Service normalization rules. Beyond the deferral period of these benefits in 2018 and 2019, customers will receive the benefit of this amortization in 2020 through 2022 through the credits reflected in the income tax calculation, which reduces revenue requirement by approximately $65 million annually.

**Q. WHAT TAXES DOES THE COMPANY PAY?**

A. The Company pays federal and state income taxes, local property taxes, sales and use taxes, payroll taxes and several other miscellaneous taxes. Taxes other than income taxes are shown on Exhibit\_\_\_(DPP/SPA/MBR-5, Schedule 5) and the computation of income taxes is shown on Exhibit\_\_\_(DPP/SPA/MBR-5, Schedule 6, Workpaper 1).

**Q. WHAT TIMING DIFFERENCES RESULT IN DEFERRED INCOME TAXES?**

A. Exhibit\_\_\_(DPP/SPA/MBR-4, Schedule 6) identifies the categories of timing differences that result in deferred income taxes. It also shows both the provision for deferred income taxes and the reversal of income taxes deferred in prior years for each specific item. The impacts to revenue requirement related to income taxes as a result of the Tax Reform Act, including impacts to ADITs, are discussed in Section II above.

**Q. PLEASE EXPLAIN THE ADJUSTMENT FOR FUTURE NUCLEAR COSTS.**

A. In Docket No. 40161, the Commission authorized the Company to spend up to $99 million through June 2019 to investigate the option of pursuing new nuclear generation in Stewart County, Georgia. The Commission found that if the project was terminated, costs incurred toward that effort would be deferred for recovery to a regulatory asset and the timing of that recovery would be addressed in a future base rate case in which the Commission would determine the appropriate period to amortize the recovery of such costs. On March 1, 2017, the Company filed a letter with the Commission notifying its intent to suspend work related to the investigation of pursuing new nuclear generation. In accordance with the Commission’s order, the Company reclassified the $48.8 million of costs incurred to a regulatory asset and proposes to amortize such costs ratably over the three-year period ending December 31, 2022. This site will remain in the Company’s portfolio and available as a possible site for new generation facilities such as nuclear, gas and renewables.

**Q. PLEASE EXPLAIN THE ADJUSTMENT FOR OBSOLETE INVENTORY OF DECERTIFIED PLANTS.**

A. As approved by the Commission in Docket Nos. 34218, 36498, and 40161, obsolete materials and supplies associated with decertified units in those proceedings have been reclassified to a regulatory asset, net of any salvage credits. The Company proposes to amortize the $44.5 million of obsolete inventory, which includes an estimate of the obsolete inventory for plants requested to be decertified in the 2019 IRP, ratably over the three-year period ending December 31, 2022.

**Q. PLEASE EXPLAIN THE ADJUSTMENT FOR NET BOOK VALUE (“NBV”) OF PLANT MITCHELL UNIT 3.**

A. As approved by the Commission in Docket No. 40161, the Company reclassified the NBV of Plant Mitchell Unit 3 to a regulatory asset as of August 2016 and continued to amortize it through December 2019 based on a period equal to the remaining useful life approved by the Commission in Docket No. 36989. The Company proposes to amortize the projected remaining regulatory asset balance as of December 31, 2019 of $4.8 million ratably over the three-year period ending December 31, 2022.

**Q. WHY DID THE COMPANY SELECT A THREE-YEAR AMORTIZATION PERIOD FOR THE THREE REGULATORY ASSETS DISCUSSED ABOVE?**

A. A three-year amortization period provides reasonable balance between rate impact to customers and timely recovery of previously incurred costs for the Company. A three-year period also provides for the amortization expense to be eliminated at the next time base rates are adjusted, presuming the Commission approves the Company’s proposed three-year ARP. This treatment is similar to the Company’s proposal to amortize the tax reform regulatory liabilities for the benefit of customers over the three-year period.

**Q. PLEASE DESCRIBE THE CURRENT ACCOUNTING FOR CAPITAL SOFTWARE AND CLOUD COMPUTING.**

A. The Company follows GAAP which provides for the accounting guidance on software and cloud computing. Under this standard, a significant portion of the software project and cloud computing costs are treated as O&M and expensed as incurred.

These costs include:

* General and administrative costs and overhead costs
* Costs incurred during the preliminary project stage to evaluate alternatives and determine final selection of the software solution
* Training costs
* Data conversion costs
* Application maintenance costs

Further, portions of costs incurred related to updates and upgrades which extend the useful life of the application may not qualify for capital treatment under current accounting guidance.

Q. WHAT CONCERNS DO YOU HAVE WITH THE CURRENT ACCOUNTING STANDARDS?

A. The current accounting standards create uneven expense recognition patterns and result in inconsistent treatment of the same or similarly focused technology project costs based on different types of technology and cost. Because of the desire for more predictable costs over time, this inconsistency in accounting treatment can influence utilities’ decisions towards certain technology and implementation approaches that are more likely to be capitalized. Ideally, selection of technology solutions and implementation approaches should be based on technology itself and maximizing benefits to customers and utilities.

Q. HAS THIS ISSUE BEEN CONSIDERED BY THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (“NARUC”)?

A. Yes. A resolution from NARUC in November 2016 summarizes this issue and the role that state regulators can play to mitigate the disparity between cloud-based and on-premise technology solutions:

Utilities best serve customers, society, the environment, and the grid by making software procurement decisions regardless of the delivery method or payment model . . . NARUC encourages State regulators to consider whether cloud computing and on-premise solutions should receive similar regulatory accounting treatment, in that both would be eligible to earn a rate of return and would be paid for out of a utility’s capital budget.

**Q. WHAT IS THE COMPANY’S REQUEST ON THE ACCOUNTING TREATMENT OF SOFTWARE AND CLOUD COMPUTING COSTS?**

A. The Company requests the Commission to allow for the deferral as a regulatory asset certain software and cloud computing project costs that would otherwise be expensed under GAAP. The Commission would address the timing of cost recovery in the next base rate case. Since the software and cloud computing arrangements provide service to customers over their useful lives, the deferral of these costs will allow the related costs to be recovered over a period more consistent with when the customers will receive the benefit of these services. This will also allow the Company to focus on the best available outcome and benefit to customers when selecting software solutions without any unnecessary bias due to a certain accounting treatment.

**Q. HOW HAVE SOFTWARE AND CLOUD COMPUTING COSTS BEEN ADDRESSED IN THIS FILING?**

A. Software and cloud computing costs have been included in this filing consistent with GAAP and past ratemaking practices. As such, approximately $40 million, or an annual average of approximately $14 million on a levelized basis, has been included as O&M expenses related to the implementation of software and/or cloud computing solutions. Should the Commission find it reasonable to adopt a policy similar to that suggested by NARUC, the Company would defer those costs to a regulatory asset and adjust its requested rate increase accordingly.

**Q. WHAT IS INCLUDED IN THIS FILING IN REGARD TO ELECTRIC TRANSPORTATION ACTIVITIES?**

A. The Company has included projected capital and O&M costs for electric transportation activities such as: (1) net investment of all the existing community electric vehicle (“EV”) charging facilities (located on and off Company property) and the associated revenues and expenses; (2) commercial and residential rebates for installing EV chargers; and (3) an amount for EV education and awareness. These activities include those that were formerly part of the Electric Transportation Pilot.  Since 2014, the Company has made approximately $3 million in capital investment in EV charging facilities, most of which has not been allowed in cost of service. In this filing, the Company includes $6 million of capital investment over the term of the ARP, recognizing that the actual amount to be invested is a policy decision by the Commission.

**Q. WHAT IS THE CURRENT ACCOUNTING TREATMENT OF GAINS AND LOSSES ON DISPOSITION OF UTILITY LAND?**

A. The Company follows the accounting guidance contained in the Code of Federal Regulations (“CFR”), which directs any gains or losses on sale of land to be recorded above the line when such property has been recorded in account 105, Electric Plant Held for Future Use (“PHFFU”), and never placed in service for the benefit for customers. Further, as provided in the CFR, gains or losses are recorded below the line if the property has been recorded in account 101, Electric Plant-in-Service (“EPIS”).

**Q. DO YOU HAVE A VIEW ON WHY THE FERC SYSTEM OF ACCOUNTS HAS TWO DIFFERENT ACCOUNTING TREATMENTS FOR THE GAINS AND LOSSES ON THE DISPOSITION OF UTILITY LAND?**

A. Yes. The logical explanation for the “above-the-line” accounting treatment provided for any gains/losses from the disposition of such property that had only been recorded in PHFFU, but never been placed in account 101, EPIS, is that this would discourage utilities from speculatively acquiring land, including it in rate base, earning a return, then selling it and retaining the gain. Whereas, the “below-the-line” accounting treatment provided for any gains/losses from the disposition of such property that had previously been recorded in EPIS, determined to be used and useful in the provision of electric service, recognizes that any residual value of such property upon disposition belongs to its owner.

**Q. PLEASE DESCRIBE THE COMPANY’S PROPOSAL AS TO THE PROSPECTIVE TREATMENT OF GAINS AND LOSSES ON DISPOSITION OF UTILITY LAND.**

A. The CFR accounting guidance is clear in the treatment of gains and losses on disposition of utility land. The Company makes prudent investments for the benefit of customers and customers, in turn, pay for the cost of electric service. The ownership does not transfer from the Company to the customers. Therefore, any gains and losses from the disposition of any land that was placed into EPIS to serve customers should be fully retained by the Company. On the few occasions when land has been sold, the above accounting guidance has been applied and accepted by the Commission.

However, the Company is sensitive to the concerns Commission Staff has raised recently related to the disposition of land. While Georgia Power has consistently followed the FERC guidance provided in the CFR, the Company agrees with Staff that the Commission has the ability to establish retail ratemaking on its own application of this guidance. As a means of facilitating efficiency going forward, the Company proposes that the Commission adopt the following policy regarding the sharing of any gains or losses on the disposition of the Company’s utility land after January 1, 2020.

Any net gains or losses on disposition of utility land, including land held in PHFFU, be shared 20% with customers with the remaining 80% to be retained by the Company. The fair market value (“FMV”) of the land will be determined at the time that it is moved from EPIS (FERC account 101) or PHFFU (FERC account 105) to non-utility property (FERC account 121) by having the land appraised by a third-party. The gain or loss subject to sharing upon the future sale will be measured by taking the difference between the FMV and the NBV of the land at the time it is transferred to non-utility property. This sharing proposal has no impact to the revenue requirement in this filing since there are no gains or losses from land sales projected in the budget. The Company is requesting that the Commission adopt this proposal for the reasons that we have already articulated in our testimony.

**Q. ARE LAND RIGHTS INCLUDED IN THE COMPANY’S PROPOSAL?**

A. No. Land rights consist of easements and rights of way that can only be utilized for utility purposes. Land right agreements cannot be transferred to other parties. If the land rights are no longer needed, the agreement would be terminated.

X. TRANSMISSION AND DISTRIBUTION INVESTMENTS

**Q. PLEASE PROVIDE AN OVERVIEW OF THE GEORGIA TRANSMISSION SYSTEM.**

A. This transmission system, along with other Integrated Transmission System (“ITS”) transmission facilities, connects approximately 15,300 MW of Georgia Power-owned, installed generating capacity. The Company also has energy available from system pool purchases and PPAs. Georgia Power participates in the ITS and owns approximately 12,500 miles of the over 17,000 miles of transmission lines that make up Georgia’s integrated transmission grid. This transmission grid is connected to 1,776 Georgia Power-owned transmission & distribution substations. The Company’s total residential, commercial, and industrial peak demand served in 2018 was approximately 15,700 MW. Transmission system voltages include 500kV and 230kV for bulk power transmission, 115kV and 161kV for much of the load-serving transmission, and sub-transmission voltages of 69kV and 46kV to supply the remaining (and typically older) load-serving facilities.

**Q. PLEASE PROVIDE AN OVERVIEW OF GEORGIA POWER’S DISTRIBUTION SYSTEM.**

A. The Company’s assigned service territory encompasses roughly 57,000 square miles across the state. The Georgia Power distribution system serves customers in all but four of Georgia’s 159 counties. The system is made up of more than 2,500 distribution feeders and approximately 215 Network Underground feeders. Feeders are distribution lines that originate from distribution substations and connect individual customers to the electric grid. Feeders are also commonly referred to as circuits.

The Georgia Power distribution system includes both overhead and underground assets. Georgia Power owns and maintains nearly 1.4 million poles, over 680,000 transformers, and nearly 49,000 miles of overhead and 26,000 miles of underground line on its distribution system.

* 1. PLEASE DISCUSS THE COMPANY’S MAJOR T&D INVESTMENTS OVER THE PAST DECADE.

A. The Company continually invests in T&D systems as needed to connect new generation and load to the grid.

In 2007, the Commission approved implementation of the Company’s $275 million AMI project and the Company replaced legacy mechanical meters with smart meters by the end of 2012. Furthermore, in 2010, the U.S. Department of Energy awarded Georgia Power a Smart Grid Investment Grant (“SGIG”). During the SGIG project, the Company increased its deployment of intelligent substation and line devices, asset health monitors, and self-healing distribution networks.[[1]](#footnote-1) From 2010 to 2013, the Company invested over $100 million in smart grid technologies under the SGIG project. Since 2013, the Company has continued its investment in system improvements similar to those undertaken during SGIG.

As load growth declined in 2007, older equipment replacements due to load growth projects also declined. Each year since 2008, the Company has increased spending on capital maintenance projects that target the replacement of aged assets. Capital maintenance spending accounted for 19% of the transmission budget in 2008 and 46% in 2018.

**Q. HAVE CUSTOMERS BENEFITED FROM THESE GRID INVESTMENTS?**

A. Yes. These investments have allowed Georgia Power to provide customers with faster power restoration times, real-time access to outage information, and innovative rate options—the Company and customers now have a more holistic view of the overall customer experience.

* Intelligent devices: The SGIG project and subsequent investments have created a network of distribution devices that can be monitored and operated remotely to decrease outage restoration times.
* Faster power restoration times: AMI has allowed the Company to proactively respond to a customer outage without a customer having to report it.
* Real-time access to outage information: The Company’s integration of AMI devices and corresponding data into its outage management system has enabled enhanced services such as personalized outage communication along with a web and mobile-based outage communication map.
* Innovative rate options: Through AMI-obtained data the Company provides innovative rate offerings.

Furthermore, smart devices have facilitated the deployment of self-healing distribution networks that segment target feeders such that a single outage affects fewer customers. As

of January 1, 2019, 1.3 million Georgia Power customers are served by a self-healing distribution network.

**Q. WHAT IS THE COMPANY’S OBJECTIVE IN MANAGING THE T&D SYSTEM?**

A. The Company’s core objective is to maintain a reliable, affordable, and safe transmission and distribution system for Georgia Power customers.

**Q. WHAT TRANSMISSION PROJECTS ARE COVERED BY THE 10 YEAR TRANSMISSION PLAN FILED TRI-ANNUALLY WITH THE COMMISSION IN THE COMPANY’S IRP?**

A.The 10-year Transmission Plan includes the future transmission facilities required to solve system inadequacies over the next 10 years and is used to demonstrate that the system is capable of reliably supporting changes in loads and resources over the same period.  The plan includes approximately 7% of the overall transmission planned budget expenditures annually.

**Q. ARE THERE SPECIFIC PROJECTS RELATED TO THE 2019 IRP THAT YOU ARE ADDRESSING IN THIS CASE?**

A. Yes. Commission Staff and the Company acknowledge that transmission issues must be addressed to preserve the retirement option for Plant Bowen 1 and 2 and agree that this rate case is the appropriate forum for discussing potential transmission solutions. Importantly, to preserve the retirement option for future consideration, the Company must start taking steps towards construction and completion of the appropriate transmission solutions. As the Company refines transmission analyses along with potential solutions, the Company will consider all practical and economic solutions, including non-traditional transmission solutions, to address the constraints that will result should Bowen Units 1 and 2 be retired.

**Q.** **WHAT OTHER T&D INVESTMENTS WILL YOU BE DISCUSSING IN YOUR TESTIMONY?**

A. For the remainder of this Section we will be discussing the Company’s intention to make needed T&D investments through our grid investment plan. Although not a major driver of revenue requirements in this rate case, the Company plans to invest an additional approximately $7.5 billion over the next 12 years for T&D. In that regard, the grid investment plan is a multi-year effort that will benefit customers for years to come and will be important in future rate filings before this Commission.

**Q. HOW DOES THE COMPANY CATEGORIZE INVESTMENTS IN THE T&D SYSTEM?**

A. Investments can be categorized into five distinct groups: (1) New Business; (2) Growth/Load Flow; (3) Commitments; (4) Reliability; and (5) Maintenance.

**Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF EACH CAPITAL INVESTMENT CATEGORY.**

A. New Business includes expenditures used to purchase and install new facilities or upgrade existing facilities required to serve new customers and new load. Growth/LoadFlow includes expenditures used to meet the demand and need for increasing capacity due to customer growth and changing generation resources.  This could include new distribution feeders, transmission lines and substations, and land that will be used for future substations and transmission lines. Commitments includes expenditures used to fund projects that are required, i.e. DOT relocations. Reliability includes substation relay modifications, replacing obsolete equipment, insulation and grounding improvements, and grid modernization.  Finally, Capital Maintenance includes expenditures dedicated to replacing broken poles, replacing deteriorated conductors with an equivalent conductor, and replacing damaged or failed transformers and other equipment.  This category also includes cycle-based asset replacement programs that replace decaying poles, transformers, reclosers and substation breakers.

**Q.** **HOW DOES THE COMPANY PRIORITIZE NEEDED INVESTMENTS TO THE T&D SYSTEM?**

A. The Company reviews several factors when prioritizing investments. Among these are assessments from planning, operations, review of risks to system reliability and service, and economic prudency. To the extent possible, while responding to new business, growth and load flow, and ongoing commitments, the Company identifies system areas where improvement and maintenance spending is warranted.

**Q. WILL THE COMPANY BE INCREASING COSTS IN ANY OF THE INVESTMENT CATEGORIES IDENTIFIED ABOVE?**

A. As part of the grid investment plan, the Company will make a series of investments in T&D projects over a 12-year period. For transmission, the Company will strategically increase expenditures primarily in the Capital Maintenance category. For distribution, the Company will strategically increase expenditures primarily in the Reliability category. The Company will invest approximately $1.3 billion in the first three years. Exhibit\_\_\_(DPP/SPA/MBR-7) and Exhibit\_\_\_(DPP/SPA/MBR-8) contain more details regarding these investments.

**Q. HAS THE COMPANY HAD TO MODIFY ITS APPROACH TO ADDRESSING MAINTENANCE AND RELIABILITY INVESTMENTS?**

A. Yes. Through 2009, the Company was able to address many Capital Maintenance and Reliability issues through load growth projects. As load growth has slowed on the transmission system, the Company has developed a long range, proactive approach to address aging assets on the transmission system. The Company continues to address underperforming feeders on the distribution system with a greater emphasis on ensuring that all customers receive a similar level of reliable service. Through this approach, the Company will reduce the risk of aging infrastructure and improve the overall customer experience.

**Q.** **WHAT APPROVALS ARE YOU SEEKING IN THIS CASE FOR T&D INVESTMENTS?**

A. As with prior cases, the Company is seeking approval to undertake these investments and cost recovery of the investments made during the period covered by the ARP. In this case, such investments include, but are not limited to, investments related to the transmission upgrades required should Bowen 1 and 2 or future coal units be retired as well as the work the Company will begin that is necessary to effectuate the grid investment plan. Both of these efforts will expand over multiple years, and for long term investments like the grid investment plan, the Company will continue to update the Commission on progress of these initiatives in future cases.

***Distribution Plan***

**Q. PLEASE PROVIDE AN OVERVIEW OF THE DISTRIBUTION PORTION OF THE COMPANY’S GRID INVESTMENT PLAN.**

A. The Company plans to invest in approximately 800 underperforming distribution feeders to improve reliability for customers. Underperforming feeders are described as a feeder in the third or fourth quartile across the Georgia Power system in both SAIDI and SAIFI performance. Customers receiving service from these feeders experience longer and more frequent outages than customers served from the remaining approximately 1,700 feeders. Investments have been identified for each individual feeder to improve its reliability based on the root causes of historical outages. Potential solutions include the creation of more self-healing distribution networks, utilization of advanced control and monitoring technologies, placing distribution infrastructure underground in a targeted manner, sectionalizing of customers, replacing existing framing hardware to improve basic insulation level and creating additional distribution feeder ties. This effort leverages proven solutions to address the root causes of system reliability issues.

* 1. PLEASE IDENTIFY THE PRIMARY GOALS OF THE DISTRIBUTION PROJECTS.

A. The Company is seeking to improve reliability for customers who are experiencing lower levels of reliability compared to other customers, improving the customer experience, and reducing O&M expenses over time.

**Q. HOW DOES THE COMPANY MEASURE DISTRIBUTION SYSTEM PERFORMANCE?**

A. The chart below defines the metrics the Company currently relies on to measure distribution system performance:

|  |  |
| --- | --- |
| System Average Interruption Frequency Index (SAIFI): | Average number of sustained interruptions for each customer on an annual basis. (outages > 5 minutes) |
| System Average Interruption Duration Index (SAIDI) | The total duration of interruption for the average customer during the year. (outages > 5 minutes) |

* 1. HOW DID THE COMPANY DEVELOP DISTRIBUTION PACKAGES FOR THE GRID INVESTMENT PLAN?

A. Exhibit\_\_\_(DPP/SPA/MBR-7) provides detailed information regarding investment packages. The Company evaluated every distribution feeder on the system based on a variety of factors, including traditional reliability metrics, outage drivers, and physical design. Based on that evaluation, the Company identified approximately 800 underperforming feeders that provide the greatest opportunities to improve service reliability for customers. Specifically, these 800 feeders not only fall below the company’s SAIDI and SAIFI median, but also have seen reliability performance declines over the past five years—these feeders have experienced an average SAIDI increase of 14% per year and an average SAIFI increase of 4% per year. An increase in SAIDI and SAIFI metrics represents a decline in reliability (i.e. longer and more frequent outages). The reliability of the remaining 1,700 feeders either remained flat or had improved reliability performance over the same period.

**Q. DOES THE COMPANY HAVE CONCERNS ABOUT MAINTAINING CONSISTENT CUSTOMER SATISFACTION LEVELS?**

A. Yes. The Company has determined that regions with lower reliability have lower customer satisfaction levels. Although many factors impact customer satisfaction, including reliability, price, employee interactions and a variety of other variables, the distribution strategy targets improving satisfaction for the 1.1 million customers receiving service from these underperforming feeders.

* 1. **WILL THE GRID INVESTMENT PLAN IMPROVE RELIABILITY ISSUES RELATED TO VEGETATION?**

A. Yes. The Company’s vegetation management program effectively manages conditions and threats that are on the right-of-way and in close proximity to Georgia Power-owned lines. The majority of vegetation-related outages are initiated by weather and fallen trees and limbs coming from outside of the right-of-way, which are difficult for any program to control. The distribution projects included in the grid investment plan redesign select feeders to be more resistant to vegetation-related outages.

**Q. DOES THE DISTRIBUTION PLAN CONSIDER FACTORS OTHER THAN IMPROVING RELIABILITY ON THE IDENTIFIED UNDERPERFORMING FEEDERS?**

A. Yes. The distribution plan balances the level of investment with customer outage cost savings and reduced O&M costs.

**Q. HOW DID THE COMPANY DETERMINE THE OPTIMAL LEVEL OF INVESTMENT FOR THE DISTRIBUTION PLAN?**

A. The Company determined the optimal level of investment for the distribution plan by considering three key factors. First, we looked at the reduction in economic cost to customers from outages by making the investments. Secondly, we looked at the reductions in O&M cost resulting from the investments made. Finally, we looked at the revenue requirement associated with the investments. The result is that the distribution plan proposed by the Company optimizes the level of investment utilizing these factors and targeting feeders that will produce the greatest benefits for our customers.

***Transmission Plan***

* 1. HOW DOES THE COMPANY MEASURE TRANSMISSION SYSTEM PERFORMANCE?

A. Similar, to distribution, the Company relies on SAIDI and SAIFI metrics to measure the effectiveness of transmission operations. Furthermore, the Company assesses infrastructure performance on an ongoing basis.

* 1. **HOW HAS GEORGIA POWER’S TRANSMISSION SYSTEM PERFORMED UNDER THESE METRICS?**

A. Georgia Power’s expertise in maintaining assets and equipment, careful prioritization of resources, strategic use of proactive maintenance programs and networked design of the transmission system have allowed it to improve transmission system reliability and performance. However, Georgia Power must make strategic investments to ensure that it can continue providing cost-effective and reliable service going forward.

**Q. WHAT IS THE PRIMARY GOAL OF THE TRANSMISSION PROJECTS INCLUDED IN THE GRID INVESTMENT PLAN?**

* + 1. The transmission investments focus exclusively on mitigating the risk of outages associated with aging assets and infrastructure. A significant portion of the Company’s transmission assets are approaching or have exceeded their expected lives. Currently, 46% of substation transformers are past the industry expected life and without this program, 60% of substation transformers on the system would be past their expected life by the end of the grid investment plan in 2031. Similarly, 24% of voltage regulators are currently past the industry expected life and 72% will be past their expected life by 2031. For substation breakers, 28% are currently past their industry expected life and 41% will be past their expected lives by 2031.

**Q. PLEASE EXPLAIN HOW THE COMPANY SELECTED TRANSMISSION INVESTMENTS.**

A. Exhibit (DPP/SPA/MBR-8) contains detailed information regarding transmission investment package descriptions. For both transmission lines and T&D substations, the Company used asset age to develop the transmission system investments.

**Q. HOW MANY TRANSMISSION SUBSTATIONS AND TRANSMISSION MILES DID THE COMPANY SELECT FOR ADDITIONAL INVESTMENT?**

A. The Company identified approximately 380 substations for investment, which represents approximately 20% of the total Georgia Power-owned substations. These substations have the oldest equipment and the highest risk of causing future outages. The Company will invest in approximately 1,050 transmission line miles, which represents approximately 8% of the total Georgia Power-owned lines. These represent the oldest transmission lines with conductor in the poorest condition.

**Q. YOU MENTIONED THAT GEORGIA POWER HAS IMPROVED TRANSMISSION SYSTEM RELIABILITY AND PERFORMANCE THROUGH ITS EXPERTISE IN MAINTAINING ASSETS AND EQUIPMENT. PLEASE EXPLAIN.**

A. In many cases, the Company has extended the service lives of assets and equipment well beyond their industry standard expected lives. Accordingly, the Company has begun increasing capital maintenance and reliability programs to replace aging infrastructure over the past decade. Programs such as the Overhead Ground Wire Replacement Program and the End of Life Transformer Replacement Program represent efforts to replace assets that were predicted to fail. These programs are designed to reduce reliability problems from equipment failure by using a statewide approach to identify the highest priority replacements. Even with the increase in spending, only a very small percentage of the assets in service are being replaced in any given year as a result of these programs.

**Q. HOW WILL THE TRANSMISSION INVESTMENTS MITIGATE RISK ASSOCIATED WITH AGING INFRASTRUCTURE?**

A. By implementing the grid investment plan, the Company will reduce the number of assets beyond their expected life on the system, thereby reducing the likelihood of failures and ensuring the integrity of the system.

**Q. WHAT WILL HAPPEN IF THE COMPANY DOES NOT UNDERTAKE THESE STRATEGIC INVESTMENTS?**

A. If the Company does not undertake these strategic investments, the risk of outages and equipment failure, including costly catastrophic equipment failure will increase. This risk will be more consequential during periods of high system load and/or high construction and maintenance workload. The Company cannot predict the precise timing of negative consequences, much like maintenance of a vehicle. Even with the best maintenance routines—oil changes, tire rotations, tune-ups, components of a car will wear out and fail, and components must ultimately be replaced to keep the car on the road. Similarly, the collective expertise of Georgia Power’s organizations leads the Company to believe that the grid investment plan is immediately necessary. If the Company does not increase investment now, it will jeopardize system performance and increase costs. Those cost increases come in the form of additional customer outages, increased costs of re-dispatching generation out of economics, increased maintenance costs to maintain aged equipment, and increased replacement costs associated with unplanned, and potentially catastrophic, failures.

XI. GEORGIA POWER’S 2019 INTEGRATED RESOURCE PLAN

**Q. PLEASE EXPLAIN THE ADJUSTMENTS RELATED TO THE COMPANY’S PENDING DECERTIFICATION REQUESTS IN THE 2019 IRP.**

A. This base rate filing reflects assumptions consistent with the Company’s 2019 IRP. Accordingly, the remaining NBV of Plant Hammond Units 1-4 has been reclassified to a regulatory asset account as of the expected Commission decision date and amortized ratably over a period equal to the respective unit’s remaining useful life as established in the depreciation study approved as part of the Company’s 2013 Rate Case. This filing also reflects reclassifying the remaining NBV of Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2 to regulatory asset accounts as of the expected Commission decision date and amortizing ratably over the three-year period ending December 31, 2022. Accordingly, these units have been excluded from the depreciation study filed in this proceeding and depreciation on these units will cease when the NBV is reclassified to regulatory assets. In addition, the Company reclassified $17.5 million of estimated unusable material and supplies inventory from Plants Hammond and McIntosh to a regulatory asset and proposes to amortize this amount ratably over the three-year period ending December 31, 2022. Similar to the NBV and obsolete inventory associated with previously decertified units, the regulatory assets and associated amortization amounts have been included in the ECCR revenue requirement.

XII. WHOLESALE SALES

**Q. PLEASE DESCRIBE THE TYPES OF SALES THE COMPANY TYPICALLY MAKES IN THE WHOLESALE MARKETS.**

A. Generally, there are three types of sales Georgia Power makes to the wholesale market. The first is Economy Energy/Opportunity sales, the second is Market-Based Tariff sales from non-specified generating units, and the third is Wholesale Block Power and Solar sales from dedicated units. The Company also facilitates the transfer of energy generated at Plant Scherer Unit 4 to its owners, Jacksonville Electric Authority and Florida Power and Light, through the Transmission Service Agreement (“TSA”). All of these sales are governed by FERC.

**Q. PLEASE DESCRIBE THE TREATMENT OF ECONOMY ENERGY/ OPPORTUNITY SALES.**

A. Economy Energy/Opportunity sales are short-term, non-firm sales to wholesale customers outside Georgia Power’s service territory. Pursuant to the Commission’s Order in Georgia Power’s 1989 rate case in Docket No. 3840 and subsequent dockets, the Company returns 75% of actual profits on economy sales to retail customers, with the Company retaining the remaining 25%.

**Q. PLEASE DESCRIBE THE TREATMENT OF MARKET-BASED TARIFF SALES FROM NON-SPECIFIED UNITS.**

A. These are sales of capacity and energy made from Company resources to off-system companies under the Southern Company FERC-approved, Market-Based Rate tariff. Consistent with the treatment of these sales in Georgia Power’s 1983 rate case in Docket No. 3397 and later updated in Docket No. 18300, the Company returns 80% of capacity revenues from these sales to retail customers, with the Company retaining the remaining 20%.

**Q. PLEASE DESCRIBE THE TREATMENT OF BLOCK POWER AND SOLAR SALES.**

A. The Wholesale Block Power and Solar sales are contractual agreements between Georgia Power and non-associated companies that currently provide for capacity and energy sales of approximately 480 MW which are priced from specific Georgia Power units. Through the transfer of wholesale capacity to retail as approved by the Commission in prior dockets as well as the retirement of certain generation units approved in the last few IRP filings, the total MW capacity sold to Wholesale Blocks has decreased significantly. Investment and expenses associated with the Wholesale Blocks are allocated based on Block Power MW sales as a percentage of the Company’s total MW ownership of the assigned units. For Wholesale Solar sales to Dalton and Tri-County, the MWs are sourced from dedicated solar generating units directly serving these customers. Exhibit\_\_\_(DPP/SPA/MBR-6, Schedule 2, Workpapers 1 and 2) reflect these Wholesale Block Power and Solar sales assignments and allocations.

Consistent with their treatment in previous rate cases, the investment, revenues and expenses related to Wholesale Block Power and Solar sales, which are sold off-system, have been assigned to wholesale cost of service and are thus excluded from retail cost of service.

**Q. WHAT OTHER WHOLESALE SALES ARE EXCLUDED FROM RETAIL COST OF SERVICE?**

A. Exhibit\_\_\_(DPP/SPA/MBR-6, Schedule 2, Workpapers 1 and 2) also includes an assignment of costs related to the Plant Scherer Unit 4 TSA. The Plant Scherer Unit 4 TSA is a cost-based long-term firm contract regulated by FERC, which sets a fixed rate of return on the transmission investments associated with the contract. Investment and expenses associated with the TSA are allocated based on specific transmission assets of 115kV and above voltage levels. Consistent with their treatment in prior rate cases, the investment, revenues and expenses related to Plant Scherer Unit 4 TSA, which are sold off-system, have been assigned to wholesale cost of service and are thus excluded from retail cost of service.

XIII. WORKING CAPITAL

**Q. PLEASE EXPLAIN THE CONCEPT OF WORKING CAPITAL AS IT RELATES TO A REGULATED UTILITY.**

A. Working capital for a regulated utility can be described as the average amount of capital (in excess of that used to finance net utility plant and other separately identified rate base components) necessary to operate the business. This capital bridges the gap from when costs are incurred by the Company to provide electric service but the payments have not yet been received from customers for that service. It also covers those items that must be financed by investors pending recovery from customers. This is different from the definition of working capital as it is used in the ordinary business or accounting sense. Working capital as applied to commercial enterprises is defined as current assets less current liabilities and is used for purposes of evaluating the liquidity of a commercial business at a given point in time.

**Q. WHAT IS INCLUDED IN THE COMPANY’S WORKING CAPITAL REQUIREMENT?**

A. The working capital requirement included in this filing consists of 13-month average balances of materials and supplies inventories, minimum bank balances, and prepayments. A provision for cash working capital (i.e., the cash necessary to pay operating expenses prior to collection of revenues net of payments) is included in overall working capital. Exhibit\_(DPP/SPA/MBR-4, Schedule 4, Workpaper 1) provides a summary of the Company’s working capital components included in this filing. In addition, Exhibit\_(DPP/SPA/MBR-1, Schedule 5 MFF) provides the estimated cash working capital requirement related to municipal franchise fees.

**Q. WHAT METHOD WAS USED IN COMPUTING THE COMPANY’S CASH WORKING CAPITAL REQUIREMENT FOR THE TEST PERIOD?**

A. The Company performed a lead-lag study to determine the estimated cash working capital requirement for the test period. The study method used in this filing is consistent with studies approved by this Commission in prior rate case proceedings. The lead-lag methodology performed involves a study of the time lag between the date customers receive service from the Company and the date they pay for such service. This is reduced by any offsetting lead time between the date suppliers and employees render service to the Company and the date the Company pays for such services.

This lead-lag methodology is generally accepted as the most reliable method for determining a cash working capital requirement and has historically been the stated preference of this Commission. One of the most important aspects of this methodology is that it provides specific analysis of day-to-day operations of the Company, and the results are applied to specific Company cost of service accounts. It does not rely on point-in-time balances from historical accounting records; rather, it provides a picture of the average flow of funds a utility requires in its operating cycle which can be applied to projected expenses to determine cash working capital. Although this approach is much more time-consuming than some other methods, it produces a more refined analysis. A complete description of the lead-lag study is included in Appendix Exhibit 3.

**Q. Does this conclude your testimony?**

A. Yes.

1. Self-healing networks are also known as FLISR (Fault Location Isolation and Service Restoration) schemes. [↑](#footnote-ref-1)