**DIRECT TESTIMONY OF**

**LEE EVANS**

**ON BEHALF OF**

**GEORGIA POWER COMPANY**

**DOCKET NO. 44280**

i. iNTRODUCTION

1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.
2. My name is Lee Evans. I am the Director of Demand Planning & Analysis for Southern Company Services, Inc. (“SCS”). My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

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

A. I received a Bachelor of Science degree in Financial Management from Clemson University in 2006 and a Master of Science degree in Finance from Georgia State University in 2013. I have also served as an Adjunct Instructor of Finance for the University of West Florida. I am a licensed Certified Public Accountant and a member of the American Institute of Certified Public Accountants. Additionally, I am a member and past chair of the Southeastern Electric Exchange’s Rates and Regulations committee and a member of the National Economic Research Associates (“NERA”) Marginal Cost working group and the Edison Electric Institute Rates and Regulatory Affairs committee.

I began my career as an intern with SCS in 2006 and worked in various roles within the Accounting and Corporate Finance organizations. In 2011, I joined Gulf Power Company (“Gulf Power”) in Revenue Accounting and later joined the Gulf Power Regulatory and Cost Recovery organization, where I focused on rate design and tracking for cost recovery clauses and the coordination of regulatory filings. In 2015, I became the Pricing, Costing & Load Research Supervisor, where I oversaw the planning, implementation, and evaluation of retail electric prices. I also supervised the planning and production of cost studies that serve as an input toward pricing and the load research function. Then, in 2018, I worked as a Project Manager in Georgia Power Company’s (“Georgia Power” or the “Company”) Pricing & Rates organization, where I was responsible for leading various costing and pricing initiatives.

In 2019, I assumed roles of increasing responsibility at SCS, each of which oversaw developing and supporting system marginal costing tools and regulated cost-of-service studies. In 2022, I was promoted to Director of Demand Planning & Analysis of SCS. My current responsibilities, in addition to the costing function, include developing strategies and overseeing analyses that influence end-use customer demand and their integration into the planning process.

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

1. Yes, I testified before this Commission in Georgia Power’s 2022 Integrated Resource Plan (“IRP”) in Docket No. 44160.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

1. The purpose of my testimony is to present and explain the cost-of-service studies filed by the Company in this proceeding, which are contained in Exhibit\_\_\_(LPE-1) through Exhibit\_\_\_(LPE-8).

Q. WHAT IS A COST-OF-SERVICE STUDY AND WHAT IS ITS PURPOSE?

A. A cost-of-service study separates a utility’s total electric investments, revenues, and expenses among the jurisdictions an electric utility serves – for example, retail and wholesale – and then among the rate groups within each jurisdiction. The purpose of a cost-of-service study is to identify what costs are incurred to provide service to certain groups of customers. Such a study enables a regulatory commission to review a utility’s earnings and to evaluate the corresponding revenue and costs associated with rates within the commission’s jurisdiction. Like other electric utilities, Georgia Power maintains its books and records in accordance with the Uniform System of Accounts as directed by the Federal Energy Regulatory Commission (“FERC”) and this Commission. Although this system of accounting tracks company-wide information, it does not separate the Company’s investments or expenses by jurisdiction (i.e., wholesale or retail) or by the rate groups within each jurisdiction. The cost-of-service study performed by the Company in this proceeding accomplishes this objective of separating costs by jurisdiction, rate groups, and rates. It does so using generally accepted methodologies and practices that are consistent with the Company’s prior filings.

Q. PLEASE DESCRIBE THE CONTENTS OF THE EXHIBITS FILED IN SUPPORT OF YOUR TESTIMONY.

1. The contents of the exhibits filed in support of my testimony are as follows:

* Exhibits LPE-1 and LPE-2 are two separate projected Period II cost-of-service studies for the 12-month period ending July 31, 2023. These studies use the Company’s recommended allocation methodologies, which are based upon principles of cost-causation. In Exhibit LPE-1, the customer categories are rate groupings; in Exhibit LPE-2, the customer categories are individual rates.
* Exhibits LPE-3 and LPE-4 are two separate historical Period I cost-of-service studies for the 12-month period ending December 31, 2021. Like Exhibits LPE-1 and LPE-2, these studies use the Company’s recommended allocation methodologies, which are based upon principles of cost-causation. In Exhibit LPE-3, the customer categories are rate groupings; in Exhibit LPE-4, the customer categories are individual rates.
* Exhibits LPE-5 and LPE-6 are two separate Period II cost-of-service studies for the period ending July 31, 2023. In contrast to the cost-of-service studies set forth in Exhibits LPE-1 and LPE-2, the studies set forth in Exhibits LPE-5 and LPE-6 utilize an alternative 4-Coincident Peak (“4-CP”) Production function allocation methodology, as advocated by some customer groups in previous cases before this Commission.
* Exhibits LPE-7 and LPE-8 are two separate Period I cost-of-service studies for the period ending December 31, 2021. As with Exhibits LPE-5 and LPE-6, the studies set forth in Exhibits LPE-7 and LPE-8 use an alternative 4-CP Production function allocation methodology, as advocated by some customer groups in previous cases before this Commission.

Notably, Exhibits LPE-5 through LPE-8 (all of which utilize the 4-CP Production function allocation) are filed for informational purposes only and are not recommended by the Company. Additionally, Exhibits LPE-1 through LPE-8 each have 13 schedules, which set forth the results of the specific cost-of-service study included in the respective exhibits, along with the supporting analyses.

Due to the voluminous size of the eight exhibits, I have provided hard copies of the exhibits’ summary pages and full copies of the exhibits in .pdf format have been made available electronically. Those files are designated as Exhibit LPE-1.pdf through Exhibit LPE-8.pdf.

Q. WHO PREPARED THE COST-OF-SERVICE STUDIES THAT YOU ARE SPONSORING IN THIS FILING?

1. The cost-of-service studies presented in this filing were prepared under my direction at the request of Georgia Power.
2. DO YOU BELIEVE THAT THE RECOMMENDED ALLOCATION METHODOLOGIES ARE THE MOST APPROPRIATE METHODOLOGIES TO BE USED BY THIS COMMISSION IN THIS CASE?
3. Yes, I do. The methodologies recommended in this filing are consistent with those filed by the Company and accepted by this Commission in previous cases. These methodologies have influenced the Company’s current rate designs and the parity adjustments previously determined by the Commission. These methodologies appropriately reflect cost causation principles that are objective and fair to different customer groups and provide accurate and reliable results.

**II. COST OF SERVICE EXPLANATION AND USE**

1. IN PREPARING A COST-OF-SERVICE STUDY, WHAT IS THE OVERALL GUIDING PRINCIPLE OR CONCEPT THAT SHOULD BE FOLLOWED?
2. The overall objective of a cost-of-service study is to assign or allocate costs fairly and equitably to all customers. This objective is met when the cost-of-service study reflects “cost causation” by allocating costs to those customers who caused the costs to be incurred by the Company in providing them service.

When certain costs are readily identified with a specific customer group, the direct assignment of those costs to that group clearly reflects cost causation and is fair and equitable to all customers. However, most parts of an electric system are planned, designed, constructed, operated, and maintained to jointly serve all customers. Accordingly, most of Georgia Power’s costs have been incurred to serve *all* customers, and these costs are referred to as “joint” or “common” costs. Rather than be assigned to a specific customer group, joint or common costs must be allocated to customer groups based on the nature of the costs and the aggregate requirements and service characteristics of the customers that caused the costs to be incurred. By adhering to this fundamental principle of cost causation, the results of the cost-of-service study will be fair and equitable to all customers.

1. HOW ARE COST-OF-SERVICE STUDIES USED IN THE REGULATORY PROCESS?
2. A cost-of-service study is typically used to determine earnings and examine how costs are being recovered from each regulatory jurisdiction, as well as from the customers or customer groups within each jurisdiction. The respective regulatory body can use these jurisdictional cost-of-service results to ascertain the utility’s overall revenue requirement as well as judge the adequacy of rates within that jurisdiction. The National Association of Regulatory Utility Commissioners (“NARUC”) recognizes the cost-of-service study among the basic tools of ratemaking.

**Q. HOW DID GEORGIA POWER USE THE COST-OF SERVICE STUDIES IN THIS RATE FILING?**

1. The Company used the jurisdictional separation of rate base and net operating income developed in the various schedules of Exhibit LPE-1 to help determine the jurisdictional revenue increase needed to achieve the requested rate of return. These jurisdictional separations were calculated according to accepted cost-of-service principles and methodologies previously filed with this Commission. The Company also considered information from the proposed cost-of-service study in the design of proposed rates for the retail customers in this docket as described in Mr. Legg’s testimony.
2. WHERE DID YOU GET THE FINANCIAL DATA USED IN THE COST-OF-SERVICE STUDIES?
3. The Company provided the financial information for the cost-of-service studies filed in this proceeding. The Company’s investment, revenue, and expense items were then (i) directly assigned to a specific jurisdiction and rate group where costs were explicitly known to be caused by a specific rate group, and (ii) allocated to jurisdiction and rate groups and specific rates where costs were determined to be jointly caused by the different groups of customers.
4. HOW WERE WHOLESALE CUSTOMERS TREATED FOR COST-OF-SERVICE PURPOSES?
5. To ensure that retail jurisdictional allocations were appropriately made, the investment, revenues, and expenses associated with wholesale customers were identified and then removed from the Company’s Total Electric System (as depicted in the cost-of-service studies) before most allocations were made. The remaining investment, revenue, and expense items were then assigned or allocated to the retail rate groups within the retail jurisdiction. This method is consistent with the methodology filed by the Company and accepted by this Commission in previous cases.
6. WHAT ARE THE MAJOR DRIVERS THAT CAUSE COSTS TO BE INCURRED BY THE UTILITY?

Utility costs typically possess three primary characteristics or drivers that identify the link between customer and company (i.e., cost causation). These costs can be categorized as: (1) demand related, which are costs that are incurred to serve peak needs for electricity; (2) energy related, which pertain to costs that vary with energy consumption; and (3) customer related, which vary with the number of customers or the fact that each customer must have the ability to receive electric service. Each of these three drivers has its own separate and appropriate allocators to spread respective costs to the appropriate jurisdiction and to rate groups within that jurisdiction. It is important to properly classify costs to ensure that they are appropriately allocated and yield accurate results. Otherwise, conclusions drawn from the study would be misleading and potentially harmful, for instance, if they influenced subsequent rate design or rate parity adjustments.

1. PLEASE PROVIDE FURTHER EXPLANATION REGARDING HOW A COST-OF-SERVICE STUDY IS PERFORMED.
2. The Company’s financial data is analyzed to determine how each group of customers influenced the incurrence of costs by the utility. This review discloses certain direct costs that should be assigned to the specific rate groups for which these costs were directly incurred. For instance, distribution FERC account 373 contains financial costs related only to street lighting; therefore, this account is directly assigned to the street lighting rate class. However, as previously mentioned, the majority of the Company’s costs are incurred to perform a common function within the electric system for various customer groups and must therefore be allocated as opposed to directly assigned to a specific group. To accurately allocate these common costs, which are often aggregated at a high level, such costs must first be identified by the functional service they provide and then by their voltage level of service. The next task is to sub-divide the costs into the appropriate cost-causative classification (i.e., demand, energy, and customer related classification resulting in financial data of sufficient detail to select an appropriate allocator). An example of this is the determination of the cost-causative relationship of FERC account 312-Boiler Plant Equipment. Since boiler plant equipment is typically sized for maximum demand requirements, it would be included in the demand category and referred to as within the demand component. An allocator based upon demands can then apportion FERC account 312 among the appropriate rate categories.
3. PLEASE SUMMARIZE THE STEPS CONDUCTED IN PERFORMING A COST-OF-SERVICE STUDY.
4. Typically, there are five major steps required in preparing a cost-of-service study: (1) *functionalization* of the financial accounting data; (2) *levelization* of the data; (3) cost-causative *classification* of the financial costs; (4) *assignment* of certain costs and revenues; and (5) *allocation* of the common costs. Step (5) requires the development of allocators, which I will explain later in my testimony. After these steps are completed, one can observe how well customer groupings cover their cost to serve.
5. PLEASE EXPLAIN THESE FIVE STEPS IN MORE DETAIL.

A. Step 1, *functionalization,* separates the investment and expenses of the Company into specified functional categories based on the operations involved in providing electric service. The Company follows the functional categories set forth by the FERC Uniform System of Accounts, which are production, transmission, distribution, customer services (customer accounting, customer assistance, sales), and administrative and general.

Step 2, *levelization*, further separates the functionalized investment and expenses into voltage-based service levels of the system. Customers request electric service to be provided at different voltages, which are referred to as service levels. Different voltages result in different costs. The service level designations are a way of identifying and associating investment and expenses with customers and their loads at established points of electrical service. In general, the lower the voltage level of service required by the customer, the greater the cost of providing service since additional equipment is necessary to deliver lower voltage service. The following table describes each service level of the electric system.

|  |  |
| --- | --- |
| **Voltage Level** | **Level Description** |
| A | Generation |
| B-1 | Step-up Substation |
| B-2 | High Voltage Transmission Lines (>115 kV) |
| C-1 | Substations Transforming from High Voltage Transmission Line (>115 kV) to Subtransmission Voltage (<69 kV) |
| D | Subtransmission Voltage Lines (<69 kV) |
| C-2 | Substations Transforming from High Voltage Transmission Line (>115 kV) to Primary Distribution Voltage (<25 kV) |
| E | Substations Transforming from Subtransmission Voltage Lines (<69 kV) to Primary Distribution Lines (4-25 kV) |
| F | Primary Distribution Lines (4-25 kV) |
| G | Secondary Distribution (<1 kV) |

Step 3, *classification*, differentiates the levelized functional investment and expenses based on the three primary cost drivers: demand related, energy related, and customer related. These are identified by the characteristics of the investment and expenses within each function and level. Each of these three cost drivers has its own separate and appropriate allocation methodology to apportion respective costs to the associated jurisdiction, customer class, and rate group.

1. *Demand related*: Costs that are incurred to serve customers’ peak requirements for electricity. This generally refers to costs incurred by the Company to provide the capacity necessary to serve the customers’ peak kilowatt (“kW”) loads (demands) throughout the year. Demand-related costs are classified at Levels A through G.
2. *Energy related*: Costs that vary with the amount of energy utilized by the customer. These costs are comprised primarily of production fuel and variable operations and maintenance (“VO&M”) expenses, which vary with the kilowatt-hours (“kWh”) consumed by the customers. Energy-related costs are classified at Level A.
3. *Customer related*: Costs that are associated with establishing service to customers but are independent of customers’ kW and kWh consumption. This generally refers to the costs incurred by the Company to attach a customer to the distribution system and be ready to serve that customer, and for customer metering, customer billing, and certain administrative costs. Some customer-related costs may vary directly with the number of customers to be served, while others are a fixed requirement necessary for a distribution system regardless of the quantity of usage. Customer-related costs are classified at Levels F and G.

Step 4, *direct assignment*, associates specific costs and revenues with specific customers or rate groups. Finally, step 5, *allocation*, apportions the common costs of service among rate groups and requires the development of allocators.

**III. COST CLASSIFICATION OF THE DISTRIBUTION SYSTEM**

1. PLEASE DESCRIBE WHAT IS MEANT BY A MINIMUM DISTRIBUTION SYSTEM (“MDS”).
2. MDS is based on the fact that in order to simply connect a customer to the power system, a minimum amount of facilities and equipment are necessary. These minimum distribution facilities, along with meters and service drops, make up the plant investment portion of customer-related costs. The distribution facilities in excess of the minimum are classified as demand-related costs because they relate to capacity.

The MDS represents the Company’s readiness to serve a customer as opposed to the capacity needed to meet a customer’s peak demand requirements. The costs associated with the readiness to serve are independent of how much electricity a customer consumes; thus, MDS costs are classified as customer-related cost components. The MDS does not represent the costs of capacity necessary to meet a customer’s peak load requirements. The portion of the total costs of these facilities that provide capacity to meet customers’ peak load requirements is classified as a demand-related cost component.

1. DID GEORGIA POWER UTILIZE AN MDS ANALYSIS IN THIS FILING?
2. Yes. Georgia Power included the results of an MDS analysis in its classification of costs for distribution facilities, as it has done for several decades*.* The Company has relied on the MDS analysis in the parity calculation among rates and rate groups and subsequently considered the MDS with respect to any corresponding rate adjustments for over 30 years.
3. IS THE MDS ANALYSIS CONSISTENT WITH THAT UTILIZED IN THE COMPANY’S LAST RATE CASE?
4. Yes. The MDS analysis utilized in this case is consistent with the those used in prior rate cases. The Company continually makes updates and refinements to its analyses to provide this Commission with the best information to make decisions and has continued to do so in this filing. The net result of these updates and refinements is a decrease to the percentage of customer-related costs resulting from the MDS analysis.

**IV. COST ALLOCATORS**

1. WHAT ARE COST ALLOCATORS, AND WHAT ARE THEY USED FOR?
2. Cost allocators are per unit ratios, or percentages, that are based on cost-causation characteristics and applied to total common cost items (e.g., a production asset) to apportion the costs of the items to customer groups or rates. Cost allocators represent the fair share proportion of the costs of service for each customer group or rate. To best reflect cost causation across all of the assets used to provide electric service, a series of ratios are developed for the allocations of the various energy, demand, and customer cost component items.
3. HOW DID THE COMPANY DEVELOP THE COST ALLOCATORS IN THIS CASE?
4. Development began with the collection and analysis of load research data. The Company collected and then analyzed data regarding the number of customers and their respective demand and energy sales by voltage level of service, as well as territorial supply and system energy and demand losses. These demands by rate group occurred at the times of the Company’s monthly coincident peaks (“CP”) and non-coincident peaks (“NCP”). System power flows were modeled through the various voltage levels of the system. This analysis produced the “12-CP,” “4-CP,” and “NCP” demand allocators, the kWh “energy” allocators, and the “number of customers” allocator.
5. PLEASE ELABORATE ON HOW THE COMPANY DEVELOPED ENERGY AND DEMAND ALLOCATORS FOR THE VARIOUS VOLTAGE LEVELS OF SERVICE.
6. Balanced system power flows for demand and energy were developed through a model that computes total system losses for each voltage level, which the Company refers to as the power flow process. The power flow process took the total energy sales at secondary distribution, Level G, multiplied them by the loss percentage at Level G, and then combined the calculated losses and sales. The resulting amount was then added to the sales at primary distribution, Level F, and this new total was in turn multiplied by the loss percentage at Level F. This power flow calculation process was further applied at each level up through the transmission system to generation, Level A. The cumulative level sales and losses were then compared to the actual generation output. To the extent there was a difference between the total loss adjusted sales and generation output, the model adjusted the loss percentages at each level and repeated the process outlined above until the sum of the losses at each level matched the total system losses and a balanced power flow was achieved.

These total system loss percentages were then applied separately to the energy sales of each rate group to compute each rate group’s loss adjusted sales at each voltage level. The aggregation of each group’s energy sales and losses up through the system to Level A provided the basis for developing the energy allocator for VO&M costs. Since VO&M costs occur at the generation (territorial input) level, basing the energy allocator on the rate groups’ loss adjusted sales at Level A results in a fair and equitable allocation of the energy-related costs.

The Company used a similar process to calculate the 12-CP and 4-CP demand allocators. By contrast, the NCP demand allocators for Levels F and G were developed using the loss percentages calculated by the monthly CP demand flow since there is no territorial input for NCP with which to balance.

1. PLEASE EXPAND ON THE 12-CP AND NCP ALLOCATOR CONCEPTS.
2. The demand of customers can be described in many ways. A 12-CP demand is used as an allocator in the cost-of-service study where capacity is built to support the common or coincident load of customers in every month of the year. A 12-CP demand is defined as the sum of the highest kW load for the Company in each month of the 12-month period divided by twelve. At the jurisdictional, class or rate group level, 12-CP is the respective coincident demands at the time of the monthly system peaks. Using this allocator ensures that the coincident load burden placed on the system by a jurisdiction, class or rate group is allocated an appropriate share of the costs of the system. The use of this concept has been strengthened by the fact that the Company is now planning for both summer and winter reliability constraints. The summer and winter reliability planning of the Company further underscores that no one month or season is adequate at representing the coincident impact of customers on system capacity.

The NCP demand is the highest demand occurring for each rate group during the year. The NCP allocators more accurately reflect the characteristics of customer loads at the primary and secondary distribution levels and more closely approximate how the Company plans and operates these functional areas of the distribution system. This method was used to allocate distribution demand costs at Level F (primary distribution) and Level G (line transformers and secondary distribution).

1. HAS THE 12-CP METHOD BEEN USED IN PREVIOUS PROCEEDINGS BEFORE THIS COMMISSION OR BEFORE FERC?
2. Yes. The 12-CP allocation methodology was first used by the Company in Docket No. 3840 (filed in April 1989), where it was accepted by the Commission and reflected in its order. Since 1989, the 12-CP allocation methodology has been used in all subsequent cost of service studies filed by the Company with this Commission. In addition, 12-CP has been one of FERC’s preferred allocation techniques for determining wholesale jurisdictional obligations, and it has been used by the Company in its filings before FERC. It has proven to be a common and popular allocation technique employed in numerous retail filings before many state commissions throughout the United States. It is a straight-forward methodology, has a strong cost causative relationship, and has a history of providing stable and sound results.
3. WHERE IS THE 12-CP ALLOCATOR APPLIED IN THE COST-OF-SERVICE STUDIES?

A. A major application of 12-CP is to allocate production capital cost. It is also used for a portion of transmission capital cost (e.g., step-up substations) allocation.

1. PLEASE DESCRIBE HOW PRODUCTION-RELATED OPERATIONS AND MAINTENANCE COSTS WERE ALLOCATED.
2. Production-related operations and maintenance (“O&M”) running costs (i.e., VO&M) were allocated on the basis of the customer’s annual energy consumption, adjusted for losses. Fuel costs were directly identified on a rate basis and were directly offset by fuel revenue since the costs and revenues associated with fuel are handled in proceedings outside of a base rate case proceeding. Production-related O&M demand costs were allocated using the 12-CP methodology.
3. PLEASE EXPLAIN HOW TRANSMISSION-RELATED CAPITAL COSTS WERE ALLOCATED.
4. Like production-related and other costs, transmission-related capital costs were allocated in the manner in which they are incurred. With the exception of step-up substations (otherwise known as generation step-up transformers or “GSUs”), which are linked to and allocated in the same manner as production-related costs, transmission costs are incurred based upon the need for transmission capacity. Transmission capacity requirements are a function of system load requirements along with a consideration of ambient temperatures, and the bulk power flow needs.
5. HOW DO AMBIENT TEMPERATURES AFFECT TRANSMISSION CAPACITY?
6. The load carrying capability of the transmission system is inversely related to ambient temperatures. Thus, the higher the temperature, the lower the load carrying capability of a given line conductor, substation breaker, etc. The converse is also true, i.e., the lower the temperature, the higher the load carrying capability. Temperatures across Georgia Power’s transmission system are distinctly seasonal. Given sufficient transmission capacity during the hot summer months, the transmission system will effectively realize a significantly greater transmission capability during the colder winter months. Furthermore, load growth during the summer period will have a greater influence on the need for additional transmission capacity than would a comparable load growth in the winter months. Consequently, to reflect the seasonal nature of transmission costs, some form of a summer peak period allocator is appropriate. In this study, as in prior cost-of service studies filed with the Commission, the summer peak period allocator is based on an average of the coincident peak loads for the four summer months of June, July, August, and September. This is referred to as the 4-CP allocation method.
7. DO ALL TRANSMISSION-RELATED COSTS HAVE THIS TEMPERATURE SENSITIVITY THEREBY JUSTIFYING A SOLE USE OF THE 4-CP CONCEPT?
8. No, not all transmission costs are this temperature sensitive. The 4-CP method is not applicable to step-up substation facilities, and the 4-CP method is only partially applicable to bulk power transmission-related capital costs.
9. WHY IS THE 4-CP METHOD NOT APPLICABLE TO STEP-UP SUBSTATIONS?
10. Power is generated at low voltage and high current, but it is transmitted most efficiently at a higher voltage and lower current. The step-up substations provide this voltage transformation function (i.e., they prepare the generated power for efficient higher voltage transmission) but they do not provide for the transfer of power from one geographical area to another. The last point is further evidenced by the fact that step-up substations exist only at generating plant sites and all generating plants have step-up substations. Consequently, it is appropriate to allocate the capital costs associated with step-up substations in the same manner as the capital costs associated with the generating plants, which these substations directly support. Thus, the Company utilizes the 12-CP allocation method for allocating the cost of step-up substations.
11. WHY IS THE 4-CP METHOD ONLY PARTIALLY APPLICABLE FOR THE ALLOCATION OF BULK POWER TRANSMISSION-RELATED CAPITAL COSTS?
12. To exclusively use the 4-CP method to allocate these costs would not give appropriate consideration to the planning and operating interrelationship that exists between the bulk power transmission system and the generating plants. In general, the bulk power transmission system carries the generated power to the load centers through a network system. To this end, production plant generation helps support bulk power flows, provides voltage support and frequency maintenance, and imparts a certain inertial stability to the power flows across the transmission system. The transmission system helps support generation by tying generating units together for reliability and stability purposes and provides a dynamic medium for the delivery of power across the system through a grid connected to many alternate power sources and paths. While peak loads may have the greater impact on transmission planning, it is also important to recognize this very real relationship between generation and bulk power transmission facilities. Consistent with prior cost-of-service studies that the Company has filed with the Commission, the bulk power transmission system costs have been allocated using a 20 percent / 80 percent weighted average of the 12-CP / 4-CP allocators. Lower voltage service levels of the transmission function are allocated upon the 4-CP or NCP allocators depending upon specific voltage service level.
13. HOW WERE THE DISTRIBUTION-RELATED CAPITAL COSTS ALLOCATED WITHIN THE COST-OF-SERVICE STUDY?
    1. Distribution-related costs were first segregated between costs that are directly related to the requirements of setting up a customer for service (customer costs), and those costs that are directly related to the customers’ load requirements (demand costs), as previously discussed. As in prior proceedings before this Commission, customer-related costs were allocated based on the average number of customers. Depending upon the voltage level of service, distribution demand-related capital costs were either allocated on the 4-CP methodology or the rate group’s NCP demands.

Q. WHY IS THE NCP METHOD APPROPRIATE TO ALLOCATE DISTRIBUTION COSTS AT LOWER DISTRIBUTION LEVELS?

1. The NCP method is based on determining cost responsibility for each rate group on the basis of the rate groups’ maximum NCP demands rather than their contribution to the system peak. This allocator is particularly appropriate at the lower service levels of distribution service, which is comprised of primary lines, line transformers, and secondary lines, since the capital costs at these levels are essentially designed to serve the rate group’s maximum NCP loads.
2. HAS THIS NCP ALLOCATION METHOD BEEN USED PREVIOUSLY?
3. Yes, it has been used in the Company’s filings since the 1990’s and is still appropriate for this filing.
4. IN THIS COST-OF-SERVICE STUDY, HOW HAVE YOU ALLOCATED COSTS FOR GEORGIA POWER’S REAL-TIME PRICING (“RTP”) CUSTOMERS AND LOAD?
5. RTP rates differ from other electric service rates in that RTP rates consist of an embedded rate portion (which is priced under a standard rate schedule), plus a marginal or incremental portion (which is priced based upon hourly marginal costs). With regard to developing RTP load allocators, the Company’s approach has been consistent for every GPC rate case since 2004. The Customer Baseline Load (“CBL”), which is priced using embedded rates, was included in the load allocators. The revenues and expenses associated with incremental RTP sales were directly assigned to the RTP customers.

Allocating and assigning all appropriate embedded and marginal costs and revenues to the RTP rates are necessary to ensure a clear measure of the rate of return on investment. We have done this by allocating embedded production and transmission costs to the RTP customers based on their CBL load. We also allocated embedded distribution costs on their total load, consistent with our approach for all embedded firm service load. We then assigned total RTP revenue as well as the marginal costs of production and transmission to the RTP customers. These marginal costs include system lambda costs, marginal reliability costs, marginal transmission costs, and marginal cost of system losses. Assigning marginal cost to RTP customers results in a commensurate reduction in embedded cost to serve non-RTP rates. This produces an accurate accounting for the costs associated with serving RTP customers and the revenue collected from serving that load.

**Q.** **DO YOU BELIEVE THIS IS THE CORRECT COST TREATMENT FOR RTP?**

A. Yes. Because incremental RTP prices are based on marginal cost and not embedded cost, it would not be appropriate to allocate embedded production and transmission costs to incremental RTP load. To do so by possibly including incremental RTP load in the embedded production and transmission cost allocation would violate the premise of marginal costing upon which incremental RTP prices are based (i.e., RTP prices would no longer be based upon marginal costing).

**V. COST-OF-SERVICE STUDY OUTLINE**

**Q.** **PLEASE EXPLAIN THE GENERAL MAKE-UP OF EACH COST-OF-SERVICE STUDY.**

A. Page (i), the index, provides a listing of schedules that designate the three major sections of the cost-of-service study. Section 1 presents the summary of the results of the cost-of-service study by the rate groups. Section 2 presents the detailed allocation of investment, revenues, and expenses to the two jurisdictions (retail and wholesale) and to the rate groups within the retail jurisdiction. Section 3 shows the Company’s power flow diagram and the service level designations used throughout the study.

**Q. PLEASE ELABORATE ON THE INFORMATION PRESENTED IN SECTION 1 OF THE COST-OF-SERVICE STUDY.**

A. Section 1 presents, in summary form, the results of the cost-of-service study for Georgia Power for the designated period. Schedule 1.00, also known as the Summary Page, shows the Company’s total rate base, revenues, expenses, and net income separated between regulatory jurisdictions, and then within the retail jurisdiction, between the rate groups. Schedule 1.00 presents the Company’s earnings position based on present rates, Schedule 1.02 shows the allocation of cash working capital, and Schedule 1.05 develops the allocation of income taxes.

**Q.** **WHICH SECTION OF THIS STUDY DESCRIBES THE INVESTMENT ALLOCATION?**

1. In Section 2, Schedules 2.00 through 2.03 present the investment allocations. On Schedules 2.00 and 2.01, gross plant investment and accumulated provision for depreciation are analyzed and allocated to the respective rate groups identified in the heading at the top of the page. Schedules 2.02 and 2.03 set forth other items that must be considered in developing the Company’s total rate base. These items are analyzed and allocated to the various rates and rate groups as indicated by the notes contained within each schedule.

**Q.** **WHICH SCHEDULES IN THIS STUDY PRESENT THE ANALYSIS OF REVENUES AND THE ALLOCATION OF EXPENSES?**

1. Schedule 2.10 presents the analysis of revenues from sales and other operating revenues. Schedules 2.20 through 2.40 contain the expense allocations and are presented in a format similar to the schedules describing the investment allocation. Schedule 2.60 presents a listing of the allocators used in and referenced throughout the cost-of-service study.

**Q. WHAT IS SHOWN IN SECTION 3 OF THE COST-OF-SERVICE STUDY?**

1. Section 3 is a power flow diagram that shows the designation of electric service levels. The power flow diagram illustrates the various paths on which electricity flows through the Georgia Power system. These paths are indicated on the chart by vertical lines. The horizontal lines represent various points within the system established for the purpose of classifying investment and expenses and for identifying the various types of facilities used in providing electric service. The letter designations of service levels on the left side of the diagram are a means of identifying the investment and expenses with customers and customers’ loads at these established points. These levels are referred to in the study on numerous occasions. Through the use of these service levels, one can identify a customer’s service location and their relative use of the Georgia Power system. This, in turn, allows for the proper identification and association of system cost responsibility with customer service requirements at the respective service levels.

**VI. CONCLUSION**

**Q.** **ARE THE ALLOCATED COST-OF-SERVICE STUDIES FILED IN THIS PROCEEDING APPROPRIATE FOR USE BY THIS COMMISSION?**

1. Yes. The studies accurately reflect the Company’s embedded cost to serve and can be used to assess the cost to serve the retail jurisdiction, evaluate the adequacy of rate groups in covering their costs, and provide costs by rate group that can be used to design cost-based proposed rates. In addition, these studies are similar to and consistent with the allocated cost-of-service studies the Company has previously filed with this Commission.
   1. **DOES THIS COMPLETE YOUR DIRECT TESTIMONY?**
   2. Yes, it does.