BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of:	**)**	
GEORGIA POWER COMPANY'S	**)**	**DOCKET NO. 31958**
2010 RATE CASE	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

GLENN A. WATKINS

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

PUBLIC VERSION

OCTOBER 22, 2010

TABLE OF CONTENTS

PAGE

I. INTRODUCTION.....1

II. REVIEW OF REAL TIME PRICING ("RTP") CHANGES.....2

III. CLASS COST OF SERVICE 11

IV. CLASS AND RATE SCHEDULE REVENUE RESPONSIBILITY 27

V. RATE STRUCTURE DESIGN ISSUES.....31

- **A. Residential Basic Service Charge 31**
- **B. Seasonal Rate Billing 32**
- **C. Time of Use ("TOU") Tariff Provisions.....33**
- **D. Demand Side Management ("DSM") Rider 35**
- **E. Customer Service Guarantee ("CSG") 36**
- **F. Nuclear Construction Costs Recovery ("NCCR") Tariff.....37**

DIRECT TESTIMONY OF
GLENN A. WATKINS
IN THE MATTER OF THE APPLICATION OF
GEORGIA POWER COMPANY
DOCKET NO. 31958

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is James Center III, 1051 East Cary Street, Suite 601, Richmond, VA 23219.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am a Principal and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with an office in Richmond, Virginia. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Georgia, Illinois, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. A more complete description of my education and experience is provided in Staff Exhibit___(GAW-1).

Q. ON WHOSE BEHALF ARE YOU APPEARING?

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

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

A. Technical Associates has been retained by the Staff to evaluate the accuracy and reasonableness of Georgia Power Company's ("Georgia Power" or "Company") retail class cost of service study, proposed distribution of revenues by class, rate design, and other tariff issues. The purpose of my testimony, therefore, is to comment on Georgia Power's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the Staff.

II. <u>REVIEW OF REAL TIME PRICING ("RTP") CHANGES</u>

Q. PLEASE EXPLAIN THE PURPOSE OF A RTP RELIABILITY CAPACITY CHARGE.

A. The purpose of the RTP Reliability Capacity Charge is to send a price signal to customers and collect costs associated with Generation capacity during peak periods. Unlike Georgia Power's traditional rate schedules, the RTP pricing structure is intended to reflect the marginal costs of providing service to these customers. The marginal cost of electricity is comprised of two major components: marginal capacity costs and marginal energy costs.[1]

Under the current RTP pricing structure, marginal energy costs are priced and collected from the hourly lambdas.[2] Marginal capacity costs consist of Generation and Transmission costs. The marginal Transmission costs are reflected (and collected) within the RTP Transmission reliability adder mechanism. The marginal Generation capacity costs are the costs that are in question with the Company's proposed change.

Q. DOES GEORGIA POWER PROPOSE ANY CHANGES RELATING TO ITS RTP TARIFFS THAT AFFECT THE COMPANY'S BASE RATE REVENUE REQUIREMENT?

---

[1] There is also a third much smaller marginal customer cost that is not addressed in this discussion.

[2] Lambda is equal to marginal fuel costs plus variable Generation operating and maintenance expenses, where marginal fuel costs (per kWh) reflect the last (most expensive) generating unit on line in a given hour. As such, lambda's can be thought of as a utility's avoided variable costs.

A. Yes. Georgia Power proposes two changes relating to RTP revenues that will have a direct impact on the jurisdictional revenue requirement applicable to traditional tariffs. The first concerns a proposed change to the methodology for crediting Incremental RTP fuel costs to the Fuel Cost Recovery ("FCR") account. The second relates to a proposed change to the method in which Incremental RTP Reliability capacity costs are charged and collected from customers.

Q. PLEASE BRIEFLY EXPLAIN GEORGIA POWER'S PROPOSED ACCOUNTING CHANGE RELATING TO THE FCR ACCOUNT.

A. Under current practices, the FCR account reflects credits from a portion of Incremental RTP revenues based on the annual Incremental RTP energy sales (kWh) multiplied by the system's average fuel cost. In this case, Georgia Power proposes a change in which each hourly Incremental RTP kWh usage will be multiplied by the average system fuel cost for that hour and then summed throughout the year. This proposed accounting change will result in an annual shift of approximately $45 million from the FCR account to base rate revenues.

Q. DO YOU SUPPORT AND RECOMMEND APPROVAL OF GEORGIA POWER'S PROPOSED ACCOUNTING CHANGE RELATING TO THE RTP FCR CREDITS?

A. Yes. This proposed change will more accurately reflect the fuel costs associated with Incremental RTP usage (kWh) and better reflect the average fuel cost recovered from traditional tariff customers.

Q. PLEASE EXPLAIN HOW THE COMPANY'S PROPOSED CHANGE TO THE METHOD IN WHICH THE RELIABILITY CAPACITY COSTS ARE COLLECTED FROM RTP CUSTOMERS AFFECTS THE BASE RATE REVENUE REQUIREMENT.

A. In a strict sense, this proposed change will not affect the overall jurisdictional revenue requirement. However, in determining the required increase in revenues associated with traditional tariffs, any change to the RTP Incremental portion of revenue has historically

been deducted from the overall increase. In this regard, it is important to understand that although the Company's proposed change to the method in which the RTP Reliability Capacity Charge is imposed on customers will generate about $10.5 million more in revenue, Georgia Power asserts that this $10.5 million is already reflected in its forecast of RTP revenues at current rates.

According to Georgia Power, this assertion is based on the representation that the Company's revenue forecast at current rates includes an implicit provision for the collection of RTP Reliability Capacity Charges. As a result, Georgia Power claims that if its proposed change to the RTP Reliability Capacity Charge is not approved, the overall jurisdictional revenue requirement must be increased by $10.5 million.[3]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED CHANGE TO THE METHOD IN WHICH THE RTP RELIABILITY CAPACITY MECHANISM IS DETERMINED?

A. With one important clarification, yes. That is, while I concur and support the proposed change in methodology to the RTP Reliability Capacity Charge, I disagree with the proposed price associated with this charge. Whereas, the Company's proposed Capacity Charge is based on a rate of [redacted] per kW year shown in Staff Exhibit___(GAW-2), I recommend that this charge be based on a rate of $19.00 per kW year.

Q. WHAT IS THE REVENUE IMPACT OF YOUR PROPOSED CAPACITY CHARGE RELATIVE TO GEORGIA POWER'S PROPOSED RATE?

A. My proposed capacity charge of $19.00 will generate $33.408 million in revenue as compared to the $10.550 million generated under the Company's proposal. This difference represents an increase of $22.858 million above the revenue level proposed by Georgia Power ($33.408 - $10.550 million). For purposes of presentation, Staff has reflected this additional $22.858 million at current rate levels in order to be consistent

[3] This is because even though the Company's revenue forecast assumes that revenues will be collected from the RTP Reliability Capacity charge, the current methodology has not triggered this charge since at least the year 2000. As such, the proposed RTP pricing change will ensure that the Reliability Capacity Charge is triggered and that revenues will be collected.

with the Company's inclusion of its proposed $10.550 million level also at current rate levels. As such, the Staff's proposed total revenue requirement is the same regardless of whether the presentation of current rate revenues reflects the change to this RTP pricing methodology or whether the additional revenues from this change are excluded from current revenues but then reflected in the required increase.

Q. HOW WILL THE MARGINAL RELIABILITY CAPACITY COSTS BE COLLECTED UNDER THE COMPANY'S PROPOSED CHANGE TO THE RTP PRICING STRUCTURE?

A. Georgia Power has redesigned its Reliability Capacity Charge based on a mechanism to trigger this charge during annual system peak load hours. Specifically, the new method is designed to trigger this charge for about 50 hours a year during the highest system peak loads. These approximately 50 hours represent about one-half of one percent of the hours in a year. The annual marginal cost rate would then be spread over these approximate 50 critical peak hours.

Q. HOW DID GEORGIA POWER DEVELOP ITS PROPOSED RTP CAPACITY CHARGE?

A. Georgia Power claims that its proposed rate of [redacted] per kW year was developed in recognition of its currently high reserve margin (excess capacity) and the current market price of capacity in the Southeast. Furthermore, this rate is expected to increase significantly as the Company's reserve margin decreases. In the Company's follow-up response to STF-TAI-2-21, Georgia Power provided its estimates of the Reliability Capacity charge for the next several years as follows:

Year	$ Per kW Year
2011	[redacted]
2012	
2013	
2014	
2015	

By and large, the driver for the increases in the above estimates is the expected decrease in the Company's excess reserve margin over the next several years.

Q. WHY DOES THE EXPECTED DECREASE IN THE COMPANY'S EXCESS RESERVE MARGIN LEAD TO AN INCREASE IN THE RTP CAPACITY CHARGE?

A. This is simply a result of supply and demand. As Georgia Power's excess capacity (supply) decreases, the market price of this capacity is expected to increase.

Q. UNDER GEORGIA POWER'S PROPOSED RTP PRICING MECHANISM, WILL ITS PROPOSED RELIABILITY CAPACITY CHARGE INCREASE AS THE COMPANY'S RESERVE MARGIN DECREASES?

A. As I understand Georgia Power's proposal, yes. The Company would increase its rate each year commensurate with the forecasted rates noted above.

Q. WILL THE ADDITIONAL REVENUES ASSOCIATED WITH THESE RATE INCREASES ACCRUE TO RATEPAYERS OR SHAREHOLDERS?

A. Until such time as Georgia Power has another rate case, the additional revenues associated with these proposed increases to the RTP Reliability Capacity Charge will accrue to shareholders under traditional ratemaking.

Q. DOES GEORGIA POWER'S PROPOSED CAPACITY CHARGE REFLECT AN EFFICIENT AND REASONABLE ESTIMATE OF THE COMPANY'S MARGINAL COST OF CAPACITY OR AN EFFICIENT AND REASONABLE PRICE SIGNAL TO RTP CUSTOMERS?

A. No. Before I explain how marginal costs should be estimated and used for establishing regulated electric utility prices, a clear understanding of how Georgia Power recovers its total costs is required. The Company's gross investment in Production plant is more than $13 billion. The carrying costs (revenue requirement) associated with the Generation capacity costs include a return of this investment (Depreciation expense) and a return on its net investment (profit plus taxes and interest). Although Georgia Power currently has

considerable "excess capacity," traditional rate schedule customers compensate the Company for its total investment in Generation facilities (i.e., required plus excess capacity). In establishing prices for traditional rate schedules, revenues collected from Incremental RTP sales are effectively subtracted from the total cost of service. Recognizing that the Company's overall revenue requirement include the carrying costs associated with this excess capacity, Incremental RTP sales are, therefore, treated similarly to off-system opportunity sales under conditions of significant excess market supply.

In addition to the Company's investment in current facilities, Georgia Power is engaged in significant Generation plant construction projects in order to meet future energy and load requirements. Traditional ratepayer prices (rates) in this case will also include provisions to compensate the Company for these construction projects that will add new additional capacity to meet future demands.

Under the Company's logic, RTP customers should not be financially responsible for any of the Company's market inefficiencies due to excess Generation capacity, nor should RTP prices reflect any costs associated with construction projects underway to meet future system demands. On the other hand, even though Georgia Power's market based capacity costs are artificially low due to its current level of excess capacity, it seeks recovery of <u>all</u> capacity costs (required plus excess) from traditional rate schedule customers. Towards this end, a fundamental assumption (or requirement) in marginal cost pricing for regulated monopolies is that no significant excess capacity exists. That is, the marginal cost of Generation capacity should reflect the cost of adding additional capacity for a market, in equilibrium; i.e., one in which no significant excess capacity exists. This stems from the economic theory of competitive markets, in which no significant excess capacity (underutilized resources) will exist due to market forces. Any desire to set monopoly utility prices based on marginal costs rests on the premise that efficiency is best achieved when regulated (marginal cost based) rates are designed to act as a surrogate for efficient competition.

Q. WHAT IS GEORGIA POWER'S MARGINAL GENERATION CAPACITY COST UNDER EFFICIENT MARKET CONDITIONS; I.E., WITHOUT SIGNIFICANT EXCESS CAPACITY?

A. This Capacity cost would be approximately [redacted] per kW year. This annual carrying cost was obtained directly from the Company's Integrated Resource Plan ("IRP"), which estimates the annual cost of an additional peaking facility to be [redacted] per kW year.

Q. DO YOU RECOMMEND THAT THE RTP CAPACITY CHARGE BE SET BASED ON THE FULL MARGINAL COST OF AN ADDITIONAL PEAKING UNIT?

A. No. Recognizing that Incremental RTP prices have not reflected any marginal Generation capacity costs since at least the year 2000, a sudden imposition of a rate based on the full marginal cost of a peaking unit would likely create rate shock for these customers. As such, I recommend a plan of gradual increases over several years until the efficient full marginal cost of Generation is reflected in the RTP Reliability Capacity Charge.

Georgia Power's proposed rate of [redacted] per kW year is [redacted] of the full marginal cost of Generation capacity. As a result, I recommend a rate of $19.00 per kW year.

Q. HOW DID YOU DETERMINE THIS RATE?

A. The rate of $19.00 per kW year was determined based on the interruptible credits given to customers under the Demand Plus Energy Credit Rider (Schedule DPEC-2). Under this rate schedule, customers receive credits for contractually agreeing to curtail (interrupt) Incremental load during peak periods, whereby credits are based on an agreed upon maximum number of annual hours of demand reduction with options ranging from 25 to 100 hours per year. The customers that agree to potentially curtail load for 50 hours a year during system peak hours, receive a credit of $4.75 per kW for each of the four summer months. This credit equates to a rate of $19.00 per kW year ($4.75 x 4). In addition to the contractual demand credit, customers will receive an energy credit of

$0.16 per kWh for the load actually interrupted during these hours. Because a marginal decrement in load (kW) should be worth about the same as a marginal increment to load, an RTP Reliability Capacity Charge rate of $19.00 per kW year is certainly reasonable.

Q. WHAT WILL THE RELATIVE IMPACT TO RTP INCREMENTAL REVENUE BE UNDER YOUR PROPOSED CAPACITY CHARGE?

A. Under my proposed Reliability Capacity Charge, RTP customers' Incremental bill will increase slightly less than 6%. This compares to an overall increase (including fuel) of 11.4% to all other traditional rate schedule bills under the Company's proposed revenue requirement.[4]

Q. WILL THE IMPLEMENTATION OF YOUR RECOMMENDED CAPACITY CHARGE DURING CRITICAL PEAK HOURS CAUSE RTP CUSTOMERS TO SHIFT OR CURTAIL LOAD?

A. There is no doubt that the price signal sent during critical peak hours will provide an incentive to reduce load below what it otherwise would be, and I am sure some customers will react to this price signal to some degree. However, my analyses of RTP customers' load responsiveness to prices indicates that very little load will be shifted or curtailed. I have evaluated the price responsiveness (price elasticity) of RTP Incremental loads using actual historical loads as well as Georgia Power forecasted loads and have found very little reduction based on price response.

Q. PLEASE EXPLAIN YOUR ANALYSES OF RTP CUSTOMERS' RESPONSIVENESS TO SHORT-TERM PRICE CHANGES.

A. First, I evaluated RTP customers' responsiveness to price based on Georgia Power's projections (forecasted 2011) which includes its proposed Reliability Capacity Charge. My analysis of the forecasted loads is provided in Staff Exhibit ___(GAW-3). Because hourly Commercial and Industrial electric loads are dependent on work and production schedules, I compared forecasted RTP Incremental loads and lambdas (prices) during the

[4] The increase to RTP customers' incremental bills is based on the current practice of no collection of Reliability Capacity Charges.

highest system peak hours to the same hour one week before and one week after each hour in question. These percentage changes in quantity (load) were compared to the corresponding percentage changes in price. Although there are instances in which the forecasted RTP Incremental load is lower during high cost hours, there are as many, if not more, instances in which the RTP Incremental load is actually higher during the higher cost (price) hours. In short, no distinct pattern exists based on Georgia Power's forecasts.

Next, I evaluated the actual historical RTP responsiveness to price. Using a similar framework of comparing the same hours one week ahead and one week behind, I evaluated the hours during 2009 and 2010 that had the highest RTP prices (lambdas). This analysis is provided in Staff Exhibit ___(GAW-4a) and Staff Exhibit ___(GAW-4b) and shows the same lack of RTP customers' responsiveness to price as under Georgia Power's forecasts.

Finally, I evaluated actual 2009 and 2010 RTP Incremental loads for the highest system peak hours using the same criteria as described above. This analysis is provided in Staff Exhibit ___(GAW-5a) and Staff Exhibit ___(GAW-5b). As can readily be seen in Staff Exhibits ___(GAW-3) through Staff Exhibit ___(GAW-5b), there is very little sensitivity to changes in customers' usages as a result of short-term changes in RTP Incremental prices.

This lack of price responsiveness is a common phenomenon for Commercial and Industrial customers when very high prices are incurred for only a very few hours a year. The costs of rescheduling work and Production to accommodate the few high priced hours greatly outweighs the minimal increases to annual electricity bills. In technical terms, the very short-term (hourly) price elasticity of demand is said to be exceptionally inelastic.

Q. IN CALCULATING THE ADDITIONAL REVENUE THAT WILL BE GENERATED USING YOUR RECOMMENDED RTP CAPACITY CHARGE RATE PER KW YEAR, DID YOU ALSO INCORPORATE THE ADDITIONAL INDUSTRIAL SALES FORECAST OF STAFF WITNESS HUTTS?

A. No. It is my understanding that Staff witness Hutts recommends an Industrial sales forecast that is approximately 940,000 MWH higher than that the forecast of Georgia Power. Although these additional Industrial sales (and attendant load) would generate more RTP Capacity Reliability Charge revenue, I have not attempted to quantify this additional revenue. As such, my adjustment to revenues is understated relative to Staff's forecasted Industrial load.

III. <u>CLASS COST OF SERVICE</u>

Q. PLEASE EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS").

A. First, I note that there are two types of cost of service studies used for public utility ratemaking: marginal cost studies; and embedded, fully allocated cost studies. Georgia Power has utilized a traditional embedded cost of service study in this case for purposes of establishing its overall retail revenue requirement, as well as for its CCOSS. As such, I will limit my explanation to embedded class cost of service studies.

Embedded cost of service studies are often referred to as fully allocated cost studies. This is because the vast majority of an electric utility's plant investment serves all customers, and the majority of expenses are incurred in a joint manner such that these costs cannot be specifically attributed to any individual customer or group of customers. To the extent that certain costs can be specifically attributable to a particular customer (or group of customers), these costs are directly assigned in a CCOSS. However, the vast majority of Georgia Power's Production, Transmission, and Distribution plant and expenses are incurred jointly to serve all (or most) customers. These joint costs are then allocated to rate classes. It is generally recognized that to the extent possible, joint costs should be allocated to rate classes based on the concept of cost causation; i.e., costs are

allocated based on specific factors that cause costs to be incurred by the utility. Although cost analysts generally strive to abide by the concept of cost causation to the greatest extent practical, some costs (particularly overhead costs), cannot be attributed to specific exogenous factors and must be subjectively assigned or allocated to rate classes. With regards to those costs in which cost causation can be attributed, cost of service experts often disagree as to what is the most cost causative factor; e.g., peak demand, energy usage, number of customers, etc.

Q. PLEASE EXPLAIN HOW CCOSS RESULTS SHOULD BE USED IN THE RATEMAKING PROCESS.

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive certain costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records, as well as fundamental differences in opinions regarding the design or cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned earlier, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS results as one of many tools in assigning revenue responsibility.

Q. GEORGIA POWER COMPANY WITNESS MICHAEL O'SHEASY DISCUSSES A CATEGORIZATION OF COSTS AS DEMAND, ENERGY, AND CUSTOMER-RELATED AS THE MAJOR DRIVERS IN DETERMINING COSTS IN A COST OF SERVICE STUDY. ARE THESE THE SAME AS THE COST CAUSATIVE FACTORS THAT YOU DESCRIBED ABOVE?

A. Yes.

Q. DOES MR. O'SHEASY'S TESTIMONY ADEQUATELY EXPLAIN HOW THESE MAJOR DRIVERS ARE DEVELOPED AND USED IN A CCOSS?

A. Yes. Mr. O'Sheasy's testimony provides a good explanation of the major cost causation factors utilized in a CCOSS, as well as how these factors are developed.

Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR ANALYSIS OF GEORGIA POWER'S CCOSS.

A. In conducting the Staff's independent analysis, I reviewed the structure and organization of the Company's CCOSS and reviewed the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I reviewed Georgia Power's selection of allocators to specific rate base, revenue, and expense accounts. I, then, verified the accuracy of Georgia Power's CCOSS model by replicating its results using my own computer model. Finally, I adjusted certain aspects of the Company's study to better reflect cost causation and cost incidence by rate schedule and customer class.

Q. DID YOU FIND THE COMPANY'S STUDY TO BE MATHEMATICALLY ACCURATE?

A. Yes. Perhaps the most fundamental requirement of an embedded CCOSS is that the sum of the parts (classes) must equal the whole (system). This is true with respect to the allocation of financial accounts, as well as the various allocation factors. Furthermore, certain costs previously allocated are carried forward for other purposes such as for the development of composite or internal allocators and for the assignment of income taxes. In all regards, I found Mr. O'Sheasy's CCOSS to be mathematically accurate and I was able to replicate his results.

Q. WHAT COST ALLOCATION METHODOLOGIES DID MR. O'SHEASY UTILIZE WITHIN HIS RECOMMENDED CCOSS?

A. Virtually every electric utility CCOSS employs several techniques in order to allocate (or assign) specific rate base and operating income accounts to the various rate classes. These various techniques, or methodologies, are usually referred to within the context of

the three major functions of an integrated electric utility's business: Generation, Transmission, and Distribution.

With regard to Generation-related costs, Mr. O'Sheasy recommends the use of the 12-month Coincident Peak ("12-CP") method.[5] With regard to high voltage (bulk power) Transmission-related costs, Mr. O'Sheasy uses a blended approach that considers both 12-CP as well as the four highest monthly coincident peak demands ("4-CP"). Specifically, Mr. O'Sheasy's blended high voltage Transmission method utilizes a weighting of 20% 12-CP and 80% 4-CP. Lower voltage facility accounts are allocated based on either the 4-CP or class Non-Coincident Peak ("NCP") methods.[6]

With regard to Distribution-related costs, Mr. O'Sheasy has utilized a common approach that assigns costs partially on the basis of peak demand and partially on the basis of number of customers. The weighting of Distribution costs between customer and demand is known as classification of Distribution costs. With the exception of Poles, Mr. O'Sheasy classified Distribution plant based on the Zero-Intercept method. Distribution Poles investments were classified using another common method known as the Minimum Size approach.

Q. RECOGNIZING THAT SEVERAL METHODS AND TECHNIQUES ARE USED WITHIN AN ELECTRIC CCOSS, ARE THE ALLOCATIONS OF CERTAIN COST CATEGORIES MORE CONTROVERSIAL THAN OTHERS?

A. Yes. I believe it is fair to say that the vast majority of differences of opinion as to the proper allocation of costs for an electric utility relate to two areas: the methodology selected to assign Generation costs, and the approaches used to classify Distribution costs.

---

[5] It should be noted that for informational purposes, Mr. O'Sheasy also provided CCOSS results utilizing the 4-CP method to assign Generation costs.

[6] Coincident peak demands are defined as class loads at the same time (coincidental) to system peak loads; i.e., they are measured at the same point in time. Class Non-Coincident Peak demands are defined as the maximum demand for each individual class regardless of when each occurs; i.e., class demands are not coincident with one another.

Q. DID YOUR INVESTIGATION RESULT IN ANY DISAGREEMENTS WITH THE ASSUMPTIONS OR METHODOLOGIES USED BY MR. O'SHEASY?

A. To some extent, yes. Although Mr. O'Sheasy's use of the 12-CP method to allocate Generation-related costs is not totally unreasonable, it is my opinion that the use of other methods would better reflect the imposition of costs (cost causation) across classes. With regard to Transmission and Distribution-related costs, I have accepted Mr. O'Sheasy's methods.[7]

Q. WOULD YOU FURTHER EXPLAIN YOUR DISAGREEMENT WITH MR. O'SHEASY'S USE OF THE 12-CP METHOD TO ALLOCATE GENERATION COSTS?

A. Yes. As I indicated earlier, there is no single, or absolute, correct method to allocate joint Generation costs. While some methods are superior to others, it is my opinion that the results of multiple, yet reasonable, methods should be considered in evaluating class profitability as well as class revenue responsibility.

Q. WHAT OTHER METHODOLOGIES ARE USED TO ALLOCATE GENERATION-RELATED PLANT AND EXPENSES?

A. In addition to the 12-CP method employed by Georgia Power, there are several other demand allocation methods utilized in the electric industry. The current National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise Principles of Public Utilities Rates.

Q. WHY DO SO MANY GENERATION ALLOCATION METHODS EXIST FOR THE ELECTRIC INDUSTRY?

---

[7] In Georgia Power's 2007 rate case (Docket No. 25060), I provided an alternative method to allocate bulk (high voltage) Transmission costs. In that case, the impacts on class rates of return were de minimus, and continue to be negligible now. In the interest of narrowing the issues in this case, I have therefore, accepted Mr. O'Sheasy's approach to allocate Transmission costs across classes. With respect to Mr. O'Sheasy's classification of Distribution plant, I investigated the details of his studies and found them to be reasonable. As such, I have accepted his classification and allocation of Distribution plant.

A. Utilities design and build Generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate throughout the year, there would be no disagreement as to the proper assignment of Generation-related costs. All analysts would agree that energy usage in terms of kWh would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that Georgia Power experiences periods (hours) of much higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the Generation system. To further complicate matters the electric utility industry is somewhat unique in that there is a distinct energy/capacity trade-off relating to Generation costs. That is, utilities design their mix of production facilities (Generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity (kW) and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investment per kW, whereas smaller units with higher variable production costs generally require significantly less investment per kW. Due to varying levels of demand placed on the system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its cost of service.

Therefore, as a result of the energy/capacity cost trade-off, and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes.

Q. PLEASE EXPLAIN.

A. Total production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to customer classes each and every hour of the year. This would result in 8,760 hourly allocations during non-leap years. Although such an analysis is certainly possible with today's technology, the time and cost necessary for such an undertaking would likely exceed the additional benefits obtained over simpler methods. This is because the analyst does not know actual class loads each and every hour, and subjective decisions must still be made regarding the assignment of fixed investment (capacity costs) to individual hours. With this practical constraint in mind, each allocation method has its strengths and weaknesses regarding its reasonableness in reflecting cost causation as well as the cost and effort required to produce a study.

Q. BRIEFLY DISCUSS THE STRENGTHS AND WEAKNESSES OF COMMON GENERATION COST ALLOCATION METHODOLOGIES.

A. A brief description of the most common fully allocated cost methodologies and attendant strengths and weaknesses are as follows:

Single Coincident Peak ("1-CP") -- The basic concept underlying the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the 1-CP method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the 1-CP method are that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are significantly less than some of the more complex methods.

The 1-CP method has several shortcomings, however. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the electric utility industry. That is, the sole criterion for assigning one hundred percent of fixed capacity costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these

facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of Generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility such as Georgia Power had a peak load of 25,000 MW and its actual optimal Generation mix included an assortment of nuclear, coal, hydro, combined cycle and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 25,000 MW for 1 hour of the year. This is because the utility would install the cheapest type of plant, (i.e., peaker units) if it only had to consider one hour a year.

There are two other major shortcomings of the 1-CP method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. The other major shortcoming of the 1-CP method is often referred to as the "free ride" problem. This problem can easily be seen with a summer peaking utility that peaks about 5:00 p.m. Because street lights are not on at this time of day, this class will not be assigned any capacity costs and will, therefore, enjoy a “free ride” on the assignment of Generation costs that this class requires.

4-CP -- The 4-CP method is identical in concept to the 1-CP method except that the peak loads during the highest four months are utilized. This method generally exhibits the same advantages and disadvantages as the 1-CP method.

Summer and Winter Coincident Peak (“S/W Peak”) -- The S/W Peak method was developed because some utilities’ annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the S/W Peak attempts to recognize this. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one.

This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is only marginally more reasonable than the 1-CP method. However, it is my understanding that Georgia Power is consistently a summer peaking utility. Therefore, this methodology is likely not well suited in this instance.

12-CP -- Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's Generation facilities.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to a small extent under this method.

The major shortcoming of the 12-CP method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain on-going load studies. However, once a system to record class load data is in place, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

Peak and Average ("P&A") -- The various P&A methodologies rest on the premise that a utility's actual Generation facilities are placed into service to meet peak load and serve consumers demands throughout the entire year. Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how peak demands should be measured or how the weighting between Peak and Average demands should be performed, most P&A studies use class contributions to coincident-

peak demand for the "peak" portion, and weight the Peak and Average loads based on the system coincident load factor, e.g., the load factor represents the portion assigned based on consumption (average demand).

The major strengths of the P&A method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the P&A method, most other allocation methods also suffer to some degree of arbitrariness. The major potential weakness of the P&A method, however, is that a significant amount of fixed capacity investment is allocated based on energy consumption, with no recognition given to lower variable fuel costs during off-peak periods. To illustrate this shortcoming, consider an off-peak or very high load factor class. This class will consume a constant amount of energy during the many cheaper off-peak periods. As such, this class will be assigned a significant amount of fixed capacity costs, while variable fuel costs will be assigned on a system average basis. This can result in an overburdening of costs if fuel costs vary significantly by hour. However, if the consumption patterns of the utility's various classes are such that there is little variation between class time differentiated fuel costs on an overall annual basis, the P&A method can produce fair and reasonable results.

Average and Excess ("A&E") -- The A&E method also considers both peak demands and energy consumption throughout the year. However, the A&E method is much different than the P&A method in both concept and application. The A&E method recognizes class load diversity within a system, such that all classes do not call on the utility's resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish

between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the end result will be exactly the same as that achieved under the 1-CP method.

Although the A&E method bears virtually no resemblance to how Generation systems are designed, this method can produce fair and reasonable results for some utilities. This is because no class will receive a "free-ride" under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during cheap off-peak periods. As such, unless fuel costs are time differentiated, this class will be assigned a large percentage of capacity costs and not receive the benefits of cheaper off-peak energy costs. Another weakness of the A&E method is that extensive and accurate class load data is required.

Base/Intermediate/Peak ("BIP") -- The BIP method is also known as a production stacking method, explicitly recognizes the capacity and energy tradeoff inherent with generating facilities in general, and specifically recognizes the mix of a particular utility's resources used to serve the varying demands throughout the year. The BIP method classifies and assigns individual generating resources based on their specific purpose and role within the utility's actual portfolio of production resources.

A major strength of the BIP method is explicit recognition of the fact that individual generating units are placed into service to meet various needs of the system. Expensive base load units, with high capacity factors run constantly throughout the year to meet the energy needs of all customers. These units operate during all periods of demand including low system load as well as during peak use periods. Base load units are,

therefore, classified and allocated based on their roles within the utility's portfolio of resource; i.e., energy requirements.

At the other extreme are the utility's peaker units that are designed, built, and operated only to run a few hours of the year during peak system requirements. These peaker units serve only peak loads and are, therefore, classified and allocated on peak demand.

Situated between the high capacity cost/low energy cost baseload units and the low capacity cost/high energy cost peaker units are intermediate generating resources. These units may not be dispatched during the lowest periods of system load but, due to their relatively efficient energy costs, are operated during many hours of the year. Intermediate resources are classified and allocated based on their relative usage to peak capability ratios; i.e., their capacity factor.

Finally, hydro units are evaluated on a case by case basis. This is because there are several types of hydro generating facilities including run of the river units that run most of the time with no fuel costs, and units powered by stored water in reservoirs that operate under several environmental and hydrological constraints including flood control, downstream flow requirements, management of fisheries, and watershed replenishment. Within the constraint just noted and due to their ability to store potential energy, these units are generally dispatched on a seasonal or diurnal basis to minimize short-term energy costs and also assist with peak load requirements. Pumped storage units are unique in that water is pumped up to a reservoir during off-peak hours (with low energy costs) and released during peak hours of the day. Depending on the characteristics of a unit, hydro facilities may be classified as energy-related (e.g., run of the river), peak-related (e.g., pumped storage) or a combination of energy and demand-related (traditional reservoir storage). The potential weakness of the BIP method is the same as under other methods where no recognition is given to lower variable fuel costs during off-peak periods.

<u>Equivalent Peaker ("EP")</u> -- The EP method combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal cost studies. The EP method often relies on planning information in order to classify individual generating units as energy or demand-related and considers the need for a mix of base load intermediate and peaking Generation resources.

The EP method has substantial intuitive appeal in that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used and only called upon during peak load periods are allocated based on peak demands to those classes contributing to the system peak load. However, this method requires a significant level of assumptions regarding the current (or future) costs of various generating alternatives.

Q. MR. WATKINS, YOU HAVE DISCUSSED THE STRENGTHS AND WEAKNESSES OF THE MORE COMMON GENERATION ALLOCATION METHODOLOGIES. ARE ANY OF THESE METHODS CLEARLY INFERIOR IN YOUR VIEW?

A. Yes. In my opinion the 1-CP and seasonal CP (such as 4-CP) methods do not reasonably reflect cost causation for integrated electric utilities because these methods totally ignore the utilization of a utility's facilities. Perhaps the simplest way to explain this is to consider that the methodology selected is used to allocate Generation plant investment. Generation investment costs vary from a low of a few hundred dollars per kW of capacity for high operating cost (energy cost) peakers to several thousand dollars per kW for base load nuclear facilities with low operating costs. If a utility were only concerned with being able to meet peak load with no regard to operating costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality but operating costs; i.e., variable fuel costs would be astronomical, and would result in a higher overall cost to serve customers. The 1-CP and seasonal CP methods totally ignore this very important fact.

Q. HAVE YOU CONDUCTED A CCOSS THAT MORE ACCURATELY REPRESENTS THE CAPACITY AND ENERGY TRADE-OFF EXHIBITED IN GEORGIA POWER'S GENERATION PLANT INVESTMENT?

A. Yes. I have conducted a CCOSS utilizing the P&A method and another CCOSS utilizing the BIP method.[8]

Q. IN YOUR P&A STUDY, HOW DID YOU DETERMINE THE WEIGHT GIVEN TO ENERGY USAGE AND THE WEIGHT GIVEN TO PEAK DEMAND?

A. I used Georgia Power's forecasted test year retail load factor of 59.00% in order to weight the energy portion versus the peak portion of the P&A allocator.

Q. WHAT MEASURE OF PEAK DEMAND DID YOU USE FOR THE DEMAND PORTION OF THE P&A ALLOCATOR?

A. I used the Company's 4-CP demand rather than the 12-CP demand to reflect the peak nature and responsibility of class loads. I have selected this measure of peak demand because the 12-CP incorporates peak and non-peak months; i.e., spring and fall demands.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED YOUR BIP ALLOCATORS.

A. In order to reflect the capacity/energy trade-off inherent in Georgia Power's mix of generating resources, I calculated the most recent (2009) capacity factors for each Georgia Power Generating Facility. I, then, weighted each generating facility based on its respective plant investment cost. This resulted in a 67.28% energy and 32.72% peak demand weighting. The supporting calculations for this relationship are shown in Staff Exhibit___(GAW-6).

Q. MR. WATKINS, DOES STAFF EXHIBIT___(GAW-6) HELP EXPLAIN THE CAPACITY/ENERGY TRADE-OFF CONSIDERATION USED BY ELECTRIC UTILITIES IN DEVELOPING A PARTICULAR MIX OF GENERATING FACILITIES?

---

[8] In the 2007 rate case, I utilized the same methodologies. However, I referred to the BIP method as the Equivalent Peaker method in the 2007 case.

A. Yes. As can be seen in Staff Exhibit___(GAW-6), Georgia Power's larger, more expensive, generating plants have high capacity factors and lower running costs. The large base load units run most hours of the year supplying energy to all customers. In contrast, the smaller, high operating cost plants tend to have lower capacity factors meaning they are primarily used to meet peak loads. It should be noted that run of the river hydro facilities are often allocated totally on the basis of energy because of their zero fuel costs. Additionally, these facilities will run as long as sufficient water is available to turn their generator turbines. However, my analysis provided in Staff Exhibit___(GAW-6) uses the actual capacity factors for Georgia Power's run of the river facilities which are fairly low. As such, a lower percentage of run of the river hydro costs were attributed to energy in my BIP allocator than if I had assumed a 100% energy basis for these facilities.

Q. WHAT ARE THE RESULTS OF YOUR CCOSS UTILIZING YOUR P&A METHOD AND BIP METHOD TO ALLOCATE GENERATION COSTS?

A. The following rates of return are achieved at present rates for the group of eight customer classes, and for the individual rate schedules presented in the Company's CCOSS. A more detailed summary underlying these CCOSS results are presented in Staff Exhibit___(GAW-7) for the BIP study and Staff Exhibit ___(GAW-8) for the P&A study. Similar to the direct testimony presentation of Mr. O'Sheasy, I have not presented the detailed account by account printouts of my CCOSSs. However, each is available upon request.

Class	ROR At Current Rates	
	Peak And Average	Base/Intermediate Peak
Domestic	4.23%	4.34%
Small Business	7.92%	8.08%
Medium Business	8.72%	8.74%
Large Business	7.13%	6.97%
Agriculture	0.44%	0.46%
Government	2.96%	2.97%
Outdoor Lighting	8.07%	7.42%
Marginally Priced	5.37%	5.08%
Total Retail	5.77%	5.77%

Rate Schedule		
R, RM	4.25%	4.36%
TOU-REO	4.52%	4.62%
GS	5.25%	5.40%
PLS	9.10%	9.26%
OGS	9.64%	9.50%
UC	15.73%	15.33%
TOU-EO	9.47%	9.67%
PLM	8.76%	8.78%
TOU-MB	6.46%	6.39%
TOU-MAM	6.73%	6.67%
TOU-GSD	11.05%	11.09%
PLL	7.41%	7.28%
TOU-SSD	12.23%	11.58%
TOU-MLM	5.04%	4.70%
TOU-HLF	4.03%	3.89%
SAS	-1.47%	-1.47%
APS, TOU-FS, IOP	-0.86%	-0.85%
SCH	9.67%	9.64%
SLM	1.98%	2.01%
TC	-7.94%	-7.98%
G	3.63%	3.55%
EOL	8.01%	6.81%
OLG	7.52%	7.02%
OLNG	8.90%	8.35%
RTP-DA	7.38%	7.17%
RTP-HA	5.48%	5.01%
FPA	2.59%	2.34%
TOU-SC	1.60%	1.37%
Total Retail	5.77%	5.77%

Q. WHAT CONCLUSIONS CAN BE DRAWN FROM THE CCOSS SPONSORED BY MR. O'SHEASY AS WELL AS THE TWO CCOSSs THAT YOU SPONSOR?

A. As shown in the table below, although there are some differences in the absolute class rates of return (RORs), very similar results are obtained regardless of the methodology employed.

	ROR At Current Rates		
Class	12-CP (GPC)	P&A (Staff)	BIP (Staff)
Domestic	3.73%	4.23%	4.34%
Small Business	7.90%	7.92%	8.08%
Medium Business	9.19%	8.72%	8.74%
Large Business	7.90%	7.13%	6.97%
Agricultural	1.48%	0.44%	0.46%
Government	2.86%	2.96%	2.97%
Outdoor Lighting	7.62%	8.07%	7.42%
Marginally Priced	5.60%	5.37%	5.08%
	5.77%	5.77%	5.77%

As indicated above, the Domestic (Residential) class exhibits a somewhat lower ROR than the system average ROR under all CCOSS methodologies, while the Small, Medium, and Large Business classes generate higher RORs than the system average ROR. The Agricultural class ROR is consistently below the return for the system, while the Lighting class ROR is above the system average. Finally, although the aggregate Governmental class ROR is significantly below the system average ROR, individual rate classes within this class exhibit higher and lower RORs than the overall system ROR. A detailed comparison of rate specific RORs for each allocation methodology is provided in Staff Exhibit ____(GAW-9).

IV. CLASS AND RATE SCHEDULE REVENUE RESPONSIBILITY

Q. HOW DOES GEORGIA POWER PROPOSE TO ASSIGN ITS REQUESTED $808.5 MILLION RATE INCREASE?

A. Georgia Power witness Gregory Roberts states on page 9 of his direct testimony that "the Company's proposed increase is applied on an equal percentage basis before fuel costs."

Q. BASED ON THE COMPANY'S FILING, IS MR. ROBERTS STATEMENT ACCURATE?

A. By and large, yes. However, it must be understood that Georgia Power treats RTP Incremental revenues separate and distinct from regular tariff revenues. In this regard, Georgia Power's class revenue increase presentation reflects a zero increase to RTP Incremental revenue even though the Company's proposed change to the Reliability Capacity Charge will generate about $10.5 million more in revenue than the current mechanism. This is because the Company represents that even though the additional $10.5 million of Reliability Capacity Charge revenue is reflected in its revenue forecast at present rates, it has not collected these revenues absent the proposed change to the RTP Incremental Reliability Capacity Charge. As such, assuming RTP customers do not alter their usage patterns (loads) significantly on a going forward basis, they will also see an increase in their RTP Incremental charges as a result of this rate case. The Company's proposed revenue increases, by rate schedule, are provided in Staff Exhibit ___(GAW-10).

Q. IS GEORGIA POWER'S PROPOSAL OF EQUAL PERCENTAGE INCREASES TO TRADITIONAL RATE CLASSES IN THIS CASE CONSISTENT WITH ITS PROPOSALS IN PRIOR CASES?

A. Yes. In the 2007 rate case, Georgia Power also proposed equal percentage increases to traditional tariffs. Furthermore, it is my understanding that equal percentage increases were also employed in rate cases prior to 2007.

Q. YOU STATED EARLIER IN YOUR TESTIMONY THAT CCOSS RESULTS SHOULD BE USED AS ONE OF MANY TOOLS IN ESTABLISHING CLASS REVENUE RESPONSIBILITY. PLEASE EXPAND ON THIS PHILOSOPHY.

A. As is hopefully apparent, there is no absolutely correct cost of service study. In determining class revenue responsibility, it is my opinion that analysts and regulators should consider that strengths and weaknesses exist in various CCOSSs and recognize that the results of a particular study are not as accurate as a surgical science.

At the same time, some consideration should be given to revenue and cost relationships; i.e., CCOSS results. This is particularly true over time. Therefore, if CCOSS results consistently show over or under earnings across time and across CCOSS, some consideration should be given to CCOSS results.

Q. GIVEN THE DISPARITIES THAT EXIST IN CLASS RORs, DO YOU RECOMMEND SOME MOVEMENT TOWARDS NARROWING THE GAP BETWEEN THESE VARIOUS RORs?

A. Yes.

Q. MR. WATKINS, WHAT ARE YOUR RECOMMENDATIONS AS TO HOW ANY BASE RATE REVENUE INCREASE AUTHORIZED BY THE COMMISSION SHOULD BE ASSIGNED TO THE VARIOUS RETAIL CLASSES AND RATE SCHEDULES?

A. For illustrative purposes, I will first provide my revenue distribution recommendation method using Georgia Power's proposed base rate revenue increase of $808.5 million. After I explain my proposed method, I will provide a means by which any increase less than the Company's requested $808.5 million should be spread to the various retail classes and rate schedules.

In developing my recommended revenue distribution method, I considered various CCOSS results, gradualism, Commission policy, the public interest of attracting new business in Georgia Power's service area, as well as the subjective nature of revenue collection embedded in some of Georgia Power's rate schedules.

With these considerations in mind, I first evaluated various CCOSS results. Specifically, I considered Georgia Power's 12-CP CCOSS, my P&A CCOSS results, and my BIP CCOSS results.

Given the various CCOSS results with an objective to move class RORs closer together, a constraint of gradualism, and recognition of social and public policy issues, I

recommend somewhat larger percentage increases to base rates for some classes and smaller percentage increases to other classes than those proposed by Georgia Power. In accomplishing these objectives and constraints, I have utilized a common technique in which class increases are first stated as a percentage of the system-wide percentage increase. That is, those classes that exhibit an ROR at current rates less than the system average ROR, receive increases greater than 100% of the system average percentage increase; i.e., classes with lower RORs receive somewhat higher percentage increases in base rate revenues. Conversely, classes with RORs higher than the system average ROR receive less than 100% of the system-wide percentage increase. Due to its large size, I have treated the Residential class as the residual, while recognizing that the increase to this class must also be in accordance with the objectives and constraints that I have previously discussed. That is, the resulting percentage increase to the Residential class is somewhat larger than the system-wide percentage increase.

Column (2) of Staff Exhibit___(GAW-11) presents my recommended relative percentage increase to base rate revenues, while Column (3) provides the resulting absolute percentage increase at the Company proposed revenue requirement. Due to the different structure of the RTP rate schedules, I treated them somewhat differently. First, I increased the RTP Incremental revenue to reflect my proposed Reliability Capacity Charge of $19.00 per kW-year above the [redacted] rate proposed by Georgia Power. This [redacted] difference totals $22.858 million in additional revenue.[9] With regard to Customer Baseline Load ("CBL") revenues, these reflect the weighted average percentage increases to the traditional rate schedules under which the CBL portion of a RTP customer's bill is based.

Once the base revenue increases are assigned to each class, I, then, assign Georgia Power's Environmental Compliance Cost Recovery ("ECCR") revenue requirement of $395.168 million to the classes [excluding RTP Incremental and 35% of the Fixed Pricing Alternative ("FPA")] based on my proposed base rate revenues. Next, Industrial

[9] As indicated earlier in my testimony, Staff Witness Henkes has reflected this $22.858 addition (above the Company's recommendation) within current revenues, since Georgia Power also reflects its proposed $10.5 Reliability Capacity revenue within current revenue.

Load Retention ("ILR") credits and Demand Side Management ("DSM") revenues reflect the same levels as forecasted by the Company. Finally, Municipal Franchise Fee ("MFF") revenues were assigned to classes based on my proposed total revenues including fuel revenue.

Q. MR. WATKINS, PLEASE PROVIDE A COMPARISON OF YOUR RECOMMENDED CLASS AND RATE SCHEDULE REVENUE DISTRIBUTION TO THAT PROPOSED BY GEORGIA POWER.

A. Staff Exhibit___(GAW-12) provides a comparison of the Company's and my recommended revenue distribution proposals at the Company's overall revenue increase request of $808.5 million. Page 1 of this Exhibit provides a comparison of increases to Base plus ECCR revenues, while Page 2 provides percentage increases to total revenues, including fuel.

Q. MR. WATKINS, SHOULD THE COMMISSION AUTHORIZE AN OVERALL INCREASE LESS THAN THE $808.5 MILLION REQUESTED BY GEORGIA POWER, HOW SHOULD THE REVENUE INCREASE BE ASSIGNED TO INDIVIDUAL RATE SCHEDULES AND CLASSES?

A. I have designed my revenue distribution method such that it can be applied to any revenue increase authorized by the Commission. That is, the methodology set forth in Staff Exhibit ___(GAW-11) can (and should) be applied regardless of the revenue increase authorized by the Commission.

V. <u>RATE STRUCTURE DESIGN ISSUES</u>

A. Residential Basic Service Charge

Q. DOES GEORGIA POWER RECOMMEND AN INCREASE TO THE RESIDENTIAL BASIC SERVICE (CUSTOMER) CHARGE?

A. Yes. The Company proposes to increase the Residential customer charge from $7.50 to $9.00 per month. This change reflects the same percentage increase (20%) as Georgia Power's requested increase in base rate (Base plus ECCR) revenues.

While I consistently maintain that Residential customer charges should be held to a minimum, I also recognize the customer costs associated with meter reading, customer billing and accounting, and maintenance of meters and services. In this regard, I do not oppose increasing the Residential customer charge by the same percentage as the overall base rate increase. However, should the Commission authorize an overall increase less than the 20% requested by Georgia Power, the Residential customer charge should reflect the ultimate percentage increase authorized for the Residential class. For example, if Georgia Power's requested increase is reduced by 50% (to a 10% overall increase to Residential base rate revenues), the Residential customer charge would also be increased by 10% (i.e., from $7.50 to $8.25).

B. Seasonal Rate Billing

Q. DO YOU HAVE ANY RECOMMENDED CHANGES CONCERNING THE COMPANY'S SEASONAL RATE STRUCTURE?

A. With regard to the definition and relative level of seasonal rates, no. However, I do recommend a minor change in the manner in which seasonal rates are applied to customers' bills during the annual transition from winter to summer rates and from summer to winter rates.

Georgia Power's "winter" rates encompass the months of October through May, while "summer" rates are in effect between June and September. Like most utilities, Georgia Power utilizes various billing cycles such that the population of customers' meters are read throughout each month.[10] As a result, a particular month's bill reflects usage from a portion of the current month as well as a portion from the prior month. For example, during the month of June, customers whose meters are read on June 2 reflect mostly May

[10] There are about 20 billing cycles which represent the approximate number of normal work days in a month.

usage (29 days) as well as a small portion of usage during June (2 days). Similarly, customers whose bills are read on June 30 reflect almost all consumption during June.

As I understand Georgia Power's billing practices, all meters read during the two transition months of June and October reflect the seasonal rates in effect for that month. The obvious concern arises when about half (50%) of the billing period usage occurred in the prior month; i.e., about 50% of June's total billed usage occurs in May and about half of October's total billed usage occurs in September.

In order to better match the timing of usage (consumption) and seasonal prices, I recommend that usage and prices be pro-rated for the two transition months. For example, if a customer's bill is read on the 15th of June, one-half (50%) of the billing period usage will be priced based on the winter rates and one-half will be based on the summer rates. In practice, due to the blocked structure of rates, a customer's bill will be determined based on a weighted average of the current and prior month's rates in effect.

C. Time of Use ("TOU") Tariff Provisions

Q. HAS THE COMPANY PROPOSED NEW LANGUAGE FOR THE TIME OF USE TARIFFS?

A. Yes. The Company has proposed new language in the Term of Contract section of the TOU tariffs.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED LANGUAGE.

A. The Company's proposed language states that a customer's contract date will be automatically renewed on the anniversary date of the contract for an additional year, unless it is terminated within 30 days notice to the Company prior to the anniversary date.

Q. WILL THE COMPANY PROVIDE NOTICE TO CUSTOMERS THAT THE ANNIVERSARY DATE OF THEIR TOU CONTRACT IS APPROACHING AND THAT THEY WILL NEED TO PROVIDE NOTICE OF THEIR DESIRE TO CHANGE TO ANOTHER RATE SCHEDULE?

A. No. The Company's direct testimony does not make any reference to a notice that would be provided to customers. In response to STF-TAI-4-8, the Company stated that it would be willing to consider providing such a notice on the customers' bill.

Q. WHAT WOULD HAPPEN IF A CUSTOMER DOES NOT NOTIFY THE COMPANY PRIOR TO THEIR TOU ANNIVERSARY DATE BUT DESIRES TO SWITCH FROM THE TOU RATE?

A. If notice is not given by a customer within 30 days of their anniversary date, the customer will be enrolled on the TOU rate for an additional twelve month period. If the customer notifies the Company prior to the third billing month of the renewal period, the Company could rebill those two months with the tariff rate that the customer selects. If the customer notifies the Company after the third billing month of the renewal period, the Company would require the customer to complete the contract period (Response to STF-TAI-4-8).

Q. DOES STAFF AGREE THAT THE COMPANY SHOULD BE ABLE TO REQUIRE A CUSTOMER TO REMAIN ON THE TOU TARIFF AFTER THE CUSTOMER HAS BEEN ON THE RATE FOR THE INITIAL 12 MONTH PERIOD?

A. No. Staff does not agree that the Company should require a customer to remain on the TOU tariff for the remainder of an additional 12 month contract period.

Q. DOES STAFF RECOMMEND APPROVAL OF THE PROPOSED TOU TARIFF LANGUAGE?

A. No. Staff does not recommend approval of the Company's proposed tariff language contained in the Term of Contract section of the TOU Rate Schedules. Staff recommends

that as long as a customer has remained on the TOU tariff for the 12 month TOU term, the customer should be able to revert back to a tariff of the customer's choice at any time.

D. DSM Rider

Q. WHAT IS THE COMPANY PROPOSING REGARDING ITS DSM TARIFFS?

A. Georgia Power witness Roberts states that the Company is proposing to continue the Residential DSM Rider that incorporates certain changes to the Residential DSM programs as a result of the 2010 IRP and DSM Stipulation in Docket Nos. 31081 and 31082. The Company is also proposing a new DSM Rider applicable to Commercial customers (DSM-C) to recover costs approved in Docket Nos. 31081 and 31082. Additionally, the Company is proposing language to facilitate annual adjustments to the DSM Riders based on actual participation levels.

Q. ARE THERE ANY ISSUES CARRIED OVER FROM DOCKET NOS. 31081 AND 31082 THAT ARE SLATED TO BE RESOLVED IN THIS RATE CASE?

A. Yes. In its Order in Docket Nos. 31081 and 31082, the Commission stated:

> The calculation of the Additional Sum for 2011 through 2013 shall be by customer class and shall be based upon Georgia Power's current avoided cost estimates as calculated and approved in the 2010 Integrated Resource plan. The Company will receive no additional sum in 2011 and only ½ of the calculated additional sum in 2012. The program costs will be recovered in a rider collected from the class to which the program is directed. In the Company's 2010 rate case, the Commission shall determine the appropriate customer class allocation of the associated additional sum (Order at pp. 20-21).

Q. WHAT ARE THESE "ADDITIONAL SUM" COSTS?

A. The "Additional Sum" costs reflect incentive compensation to the Company for implementing its various DSM programs. Specifically, these amounts are an amount to be recovered by the Company that represent a certain percentage of the net present value of the actual net benefits with the DSM programs.

Q. HOW ARE THE VARIOUS DSM RELATED COSTS TO BE RECOVERED FROM RATEPAYERS?

A. The Commission's Order in Docket Nos. 31081 and 31082 states that the parties agree that specific program costs are to be recovered through a rider from the class to which the program is directed, and the recovery of the "Additional Sum" costs are to be determined by the Commission in this proceeding.

Q. HOW HAS THE COMPANY PROPOSED THAT THE "ADDITIONAL SUM" COSTS BE RECOVERED IN THE FUTURE?

A. My reading of the testimony of Georgia Power witnesses Daiss and Morris is that they have made no specific recommendation as to how the "Additional Sum" costs should be recovered. They have stated, however, that "projected costs" should be recovered through the DSM tariff (page 26 of their Direct Testimony).

Q. MR. WATKINS, WHAT IS YOUR PROPOSED APPROACH TO RECOVER DSM "ADDITIONAL SUM" COSTS?

A. The societal and financial objective of the Company's DSM programs is to reduce the need for additional system capacity and hence, reduce future revenue requirements that must be paid by all ratepayers collectively. In this regard, DSM programs and objectives will benefit all ratepayers such that some of the costs associated with these savings should be borne by all ratepayers. I recommend that Residential and Commercial customers should be responsible for their respective direct program costs and that all customers (except Incremental RTP load) should be responsible for the "Additional Sum" portion of the DSM costs.

E. Customer Service Guarantee ("CSG")

Q. DO YOU HAVE ANY OTHER RATEMAKING RECOMMENDATIONS?

A. Yes. Staff recommends that the Company move expenses associated with the Company's CSG policy below the line.

Q. WHAT IS THIS CUSTOMER SERVICE GUARANTEE?

A. The CSG is an internal Company practice, not included in the Company's tariff, used to provide credits to customers, who in the Company's opinion and at their discretion, have not received "good customer service." This could be defined as billing or meter reading errors among other situations in which customers may not have received the quality of customer service the Company strives to provide.

Q. HOW ARE THESE COSTS CURRENTLY EXPENSED?

A. These costs (or write-offs) are currently expensed above the line in FERC Account 910.

Q. WHAT ARE THE EXPENSE AMOUNTS FOR THE TEST PERIODS ENDING JULY 31, 2010 AND DECEMBER 31, 2011?

A. According to the Company's response to STF-TAI-2-45, the amount is $31,000.

Q. WHY IS STAFF RECOMMENDING THAT THESE EXPENSES BE MOVED TO BELOW THE LINE?

A. These are expenses that the Company applies to all ratepayers due to the Company's errors or situations in which customers are not provided a proper level of customer service. It is Staff's position that ratepayers should not bear the cost of these expenses and that the costs should be booked below the line for ratemaking purposes.

F. Nuclear Construction Costs Recovery ("NCCR") Tariff

Q. HAS GEORGIA POWER FILED A PROPOSED NCCR TARIFF?

A. Yes. On September 3, 2010, Georgia Power filed its proposed NCCR-1 tariff.

Q. WHAT IS INCLUDED IN THE COMPANY'S SEPTEMBER 3, 2010 FILING?

A. Georgia Power's filing consists of a cover letter and a one page proposed tariff.

Q. HAS THE COMPANY SUBMITTED TESTIMONY, SCHEDULES, OR OTHER EVIDENCE SUPPORTING ITS REQUESTED NCCR-1 TARIFF?

A. No.

Q. SPECIFICALLY, WHAT IS GEORGIA POWER REQUESTING IN ITS NCCR-1 TARIFF?

A. The proposed tariff would increase customers' base rate bills by an additional 5.5493%. RTP Incremental revenue and 35% of FPA-4 tariff bills would be exempt from this tariff.

Q. HAS STAFF INQUIRED AS TO HOW GEORGIA POWER DEVELOPED ITS PROPOSED NCCR-1 RATE OF 5.5493%?

A. Yes. On September 13, 2010, Staff propounded discovery on the Company inquiring as to the determination of the proposed rate. Georgia Power provided responses to Staff's discovery requests on October 13, 2010.

Q. WAS STAFF ABLE TO EVALUATE THE APPROPRIATENESS OF THE PROPOSED TARIFF AND WHETHER IT COMPORTS WITH THE REQUIREMENTS OF O.C.G.A. §46-2-25(C.1)?

A. No. Georgia Power's responses to Staff's discovery consisted of undocumented electronic spreadsheets that allegedly support its requested tariff rate. The foundation for the Company's proposed rate of 5.5493% is a 2011 "revenue requirement" of $218.219 million. Georgia Power provided a highly complex electronic Excel model that is not documented and not understood. As a result, it is not possible to evaluate if the proposed rate is or is not appropriate or whether it comports with statutory requirements.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE STATUTORILY MANDATED NCCR TARIFF?

A. I recommend that the Commission direct Georgia Power to make a meaningful filing with the Commission on or before the filing of its rebuttal case in this docket. This filing should include schedules, and any other evidence necessary for the Commission to evaluate the appropriateness of this (or any other) proposed tariff charged to jurisdictional customers.

This filing should include a complete and thorough explanation of the methodology and model used to determine the proposed NCCR revenue requirement; documented and organized schedules supporting the proposed revenue requirement; documented and organized schedules supporting forecasted base rate revenues[11]; and, a detailed proposal and explanation of whether any over or under recovery of NCCR costs will be trued-up in future periods, and if so, how this will be accomplished.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

[11] Forecasted base rate revenues serve as the denominator of the equation to develop the NCCR rate.

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jul. 1995-Present	Vice President/Senior Economist, Technical Associates, Inc.
Mar. 1993-1995	Vice President/Senior Economist, C. W. Amos of Virginia
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

<u>Confidential</u>

Georgia Power Company
Analysis and Forecast Supporting Estimated $10.5M Revenue Recovery from RTP Reliability Capacity Component 1/

Projected Peak (MW): **Redacted**
Capacity Cost ($/kW-yr): **Redacted**

Average Capacity Threshold: **Redacted**
Average Capacity Sum Reponse Function: **Redacted**

Total Projected Recovery
Redacted

[redacted]	Incremental kWh (projected RTP-DA)	Total Capacity $ RTP-DA	Incremental kWh (projected RTP-HA)	Total Capacity $ RTP-HA
Redacted				

1/ Per Response to STF-TA-2-21

Confidential

Georgia Power
RTP Forecasted 2011 Loads and Prices
(Peak 42 System Hours) 1/
Hour Ahead Incremental

RTP - Hour Ahead				System Peak Hour		Week Earlier		Week After	
month	day	hr	yr	Price ($/MWH)	Load (kWh)	Price ($/MWH)	Load (kWh)	Price ($/MWH)	Load (kWh)

Redacted

1/ Forecasted hours in which Generation Reliability Charge will apply per response to STF-TAI-2-21

Confidential

Georgia Power
RTP Forecasted 2011 Loads and Prices
(Peak 42 System Hours) 1/
Day Ahead Incremental

RTP - Day Ahead				System Peak Hour		Week Earlier		Week After	
month	day	hr	yr	Price ($/MWH)	Load (kWh)	Price ($/MWH)	Load (kWh)	Price ($/MWH)	Load (kWh)

Redacted

1/ Forecasted hours in which Generation Reliability Charge will apply per response to STF-TAI-2-21

Confidential

Georgia Power
Analysis of RTP Incremental Usage Changes
Due to Changes in Lambda

RTP-HA Lambda Analysis

Date	Time	Lambda ($/MWH) 1/	Incremental Load (MW) 2/	System Load (MW) 3/

Redacted

1/ Per Response to STF-TAI-2-8
2/ Per Response to STF-TAI-2-13
3/ Per Response to STF-TAI-2-7

Confidential

Georgia Power
Analysis of RTP Incremental Usage Changes
Due to Changes in Lambda

RTP-DA Lambda Analysis

Date	Time	Lambda ($/MWH) 1/	Incremental Load (MW) 2/	System Load (MW) 3/

Redacted

1/ Per Response to STF-TAI-2-8
2/ Per Response to STF-TAI-2-13
3/ Per Response to STF-TAI-2-7

Confidential

Georgia Power
Analysis of RTP Incremental Usage Changes
Due to Changes in Lambda

RTP-HA Lambda Analysis

Date	Time	Lambda ($/MWH) 1/	Incremental Load (MW) 2/	System Load (MW) 3/

Redacted

1/ Per Response to STF-TAI-8
2/ Per Response to STF-TAI-13
3/ Per Response to STF-TAI-7

Confidential

Georgia Power
Analysis of RTP Incremental Usage Changes
Due to Changes in Lambda

RTP-DA Lambda Analysis

Date	Time	Lambda ($/MWH) 1/	Incremental Load (MW) 2/	System Load (MW) 3/

Redacted

1/ Per Response to STF-TAI-8
2/ Per Response to STF-TAI-13
3/ Per Response to STF-TAI-7

Confidential

Georgia Power
Analysis of RTP Incremental Usage Changes
Due to Changes in Lambda

			RTP-HA		RTP-DA	
Date	Time	System Load (MW) 1/	Lambda ($/MWH) 2/	Incremental Load (MW) 3/	Lambda ($/MWH) 2/	Incremental Load (MW) 3/

Redacted

1/ Per Response to STF-TAI-2-7
2/ Per Response to STF-TAI-2-8
3/ Per Response to STF-TAI-2-13

Confidential

Georgia Power
Analysis of RTP Incremental Usage Changes
Due to Changes in Lambda

			RTP-HA		RTP-DA	
Date	Time	System Load (MW) 1/	Lambda ($/MWH) 2/	Incremental Load (MW) 3/	Lambda ($/MWH) 2/	Incremental Load (MW) 3/

Redacted

1/ Per Response to STF-TAI-2-7
2/ Per Response to STF-TAI-2-8
3/ Per Response to STF-TAI-2-13

Georgia Power Company
Development of Energy and Demand
Separation for the Equivalent Peaker Method

Plant Name	Type	Generator Nameplate (MW) 1/	Historic TY MWH 2/	Max MWH 3/	Capacity Factor 4/	Costs Plant ($000)	Costs Common 2/	Costs Total	Pct of Costs	Wtd Capacity Factor 5/
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Boulevard 1	Gas	20	0	172,572	0.00%	$749	$0	$749	0.0067%	0.0000%
Boulevard 2	Gas	20	3	172,572	0.00%	$749	$0	$749	0.0067%	0.0000%
Boulevard 3	Gas	20	0	172,572	0.00%	$749	$0	$749	0.0067%	0.0000%
Bowen 1	Coal	700	5,102,266	6,132,000	83.21%	$263,102	$40,190	$303,291	2.6980%	2.2449%
Bowen 2	Coal	700	4,681,999	6,132,000	76.35%	$211,497	$32,307	$243,803	2.1688%	1.6560%
Bowen 3	Coal	880	5,562,650	7,708,800	72.16%	$807,391	$123,332	$930,722	8.2795%	5.9744%
Bowen 4	Coal	880	6,191,276	7,708,800	80.31%	$494,160	$75,485	$569,644	5.0674%	4.0699%
Bowen 6	Coal	39	24	345,144	0.01%	$3,614	$0	$3,614	0.0322%	0.0000%
Branch 1	Coal	250	998,370	2,190,000	45.59%	$80,615	$18,539	$99,154	0.8820%	0.4021%
Branch 2	Coal	319	1,241,107	2,794,440	44.41%	$70,109	$16,123	$86,231	0.7671%	0.3407%
Branch 3	Coal	481	1,739,382	4,210,932	41.31%	$138,304	$31,805	$170,109	1.5132%	0.6251%
Branch 4	Coal	490	2,454,168	4,292,400	57.17%	$140,081	$32,214	$172,295	1.5327%	0.8763%
Gahydro	Hydro	666	2,043,522	5,836,613	35.01%	$272,812	$0	$272,812	2.4269%	0.8497%
Hammond 1	Coal	100	330,257	876,000	37.70%	$31,390	$43,746	$75,135	0.6684%	0.2520%
Hammond 2	Coal	100	357,144	876,000	40.77%	$27,138	$37,820	$64,958	0.5778%	0.2356%
Hammond 3	Coal	100	355,266	876,000	40.56%	$26,852	$37,422	$64,274	0.5718%	0.2319%
Hammond 4	Coal	500	2,372,182	4,380,000	54.16%	$211,577	$294,860	$506,437	4.5051%	2.4400%
Hatch 1 (GPC)	Nuclear	451	3,602,196	3,948,063	91.24%	$335,049	$106,848	$441,897	3.9310%	3.5866%
Hatch 2 (GPC)	Nuclear	449	2,608,528	3,932,540	66.33%	$360,686	$115,023	$475,709	4.2318%	2.8070%
Kraft 1	Coal	44	270,414	385,440	70.16%	$35,165	$0	$35,165	0.3128%	0.2195%
Kraft 2	Gas,Oil	46	272,905	402,960	67.73%	$35,165	$0	$35,165	0.3128%	0.2119%
Kraft 3	Coal	75	448,498	657,000	68.26%	$35,165	$0	$35,165	0.3128%	0.2135%
Kraft 4	Gas	116	5,283	1,017,351	0.52%	$35,165	$0	$35,165	0.3128%	0.0016%
Kraft CT 1	Gas	22	16	192,720	0.01%	$1,985	$0	$1,985	0.0177%	0.0000%
McDonough 1	Coal	245	964,138	2,146,200	44.92%	$141,401	$0	$141,401	1.2579%	0.5651%
McDonough 2	Coal	245	1,108,568	2,146,200	51.65%	$141,401	$0	$141,401	1.2579%	0.6497%
McDonough 3A	Gas	39	64	345,144	0.02%	$4,055	$0	$4,055	0.0361%	0.0000%
McDonough 3B	Gas	39	0	345,144	0.00%	$4,055	$0	$4,055	0.0361%	0.0000%
McIntosh 1	Gas	163	0	1,428,905	0.00%	$154,518	$0	$154,518	1.3745%	0.0000%

Georgia Power Company
Development of Energy and Demand
Separation for the Equivalent Peaker Method

Plant Name	Type	Generator Nameplate (MW) 1/	Historic TY MWH 2/	Max MWH 3/	Capacity Factor 4/	Costs Plant ($000)	Costs Common 2/	Costs Total	Pct of Costs	Wtd Capacity Factor 5/
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
McIntosh 10	Gas	659	3,599,016	5,776,870	62.30%	$205,575	$10,105	$215,680	1.9186%	1.1953%
McIntosh 11	Gas	659	3,490,291	5,776,870	60.42%	$211,500	$10,396	$221,896	1.9739%	1.1926%
McIntosh CT 1	Gas	80	5,590	700,800	0.80%	$21,468	$3,118	$24,586	0.2187%	0.0017%
McIntosh CT 2	Gas	80	5,611	700,800	0.80%	$20,516	$2,980	$23,495	0.2090%	0.0017%
McIntosh CT 3	Gas	80	8,443	700,800	1.20%	$23,158	$3,363	$26,521	0.2359%	0.0028%
McIntosh CT 4	Gas	80	3,964	700,800	0.57%	$23,136	$3,360	$26,496	0.2357%	0.0013%
McIntosh CT 5	Gas	80	8,583	700,800	1.22%	$27,223	$0	$27,223	0.2422%	0.0030%
McIntosh CT 6	Gas	80	3,742	700,800	0.53%	$27,223	$0	$27,223	0.2422%	0.0013%
McIntosh CT 7	Gas	80	3,652	700,800	0.52%	$23,019	$3,343	$26,363	0.2345%	0.0012%
McIntosh CT 8	Gas	80	5,388	700,800	0.77%	$23,588	$3,426	$27,014	0.2403%	0.0018%
McManus 1	#6 Oil	40	0	350,400	0.00%	$11,324	$1,093	$12,416	0.1105%	0.0000%
McManus 2	#6 Oil	75	410	657,000	0.06%	$19,858	$1,916	$21,775	0.1937%	0.0001%
McManus 3A	#2 Oil	52	689	456,396	0.15%	$5,683	$0	$5,683	0.0506%	0.0001%
McManus 3B	#2 Oil	52	753	456,396	0.16%	$5,683	$0	$5,683	0.0506%	0.0001%
McManus 3C	#2 Oil	52	585	456,396	0.13%	$5,683	$0	$5,683	0.0506%	0.0001%
McManus 4A	#2 Oil	54	975	472,164	0.21%	$5,683	$0	$5,683	0.0506%	0.0001%
McManus 4B	#2 Oil	54	1,213	472,164	0.26%	$5,683	$0	$5,683	0.0506%	0.0001%
McManus 4C	#2 Oil	54	1,101	472,164	0.23%	$5,683	$0	$5,683	0.0506%	0.0001%
McManus 4D	#2 Oil	54	724	472,164	0.15%	$5,683	$0	$5,683	0.0506%	0.0001%
McManus 4E	#2 Oil	54	495	472,164	0.10%	$5,683	$0	$5,683	0.0506%	0.0001%
McManus 4F	#2 Oil	54	1,087	472,164	0.23%	$5,683	$0	$5,683	0.0506%	0.0001%
McManus DS 1	#2 Oil	2	25	17,520	0.14%	$582	$0	$582	0.0052%	0.0000%
Mitchell 3	Coal	125	20,857	1,095,000	1.90%	$42,224	$16,981	$59,205	0.5267%	0.0100%
Mitchell 4A	#2 Oil	39	67	345,144	0.02%	$4,101	$0	$4,101	0.0365%	0.0000%
Mitchell 4B	#2 Oil	39	76	345,144	0.02%	$4,101	$0	$4,101	0.0365%	0.0000%
Mitchell 4C	#2 Oil	39	87	345,144	0.03%	$4,101	$0	$4,101	0.0365%	0.0000%
Robins 1	Gas	79	5,997	693,792	0.86%	$18,776	$2,974	$21,750	0.1935%	0.0017%
Robins 2	Gas	79	6,016	693,792	0.87%	$18,781	$2,974	$21,755	0.1935%	0.0017%
Rocky Mt	Hydro	231	332,830	2,019,180	16.48%	$170,568	$0	$170,568	1.5173%	0.2501%
Scherer 1 (GPC)	Coal	69	425,199	601,917	70.64%	$47,714	$7,445	$55,159	0.4907%	0.3466%
Scherer 2 (GPC)	Coal	69	432,584	601,917	71.87%	$45,473	$7,095	$52,568	0.4676%	0.3361%

Georgia Power Company
Development of Energy and Demand
Separation for the Equivalent Peaker Method

Plant Name	Type	Generator Nameplate (MW) 1/	Historic TY MWH 2/	Max MWH 3/	Capacity Factor 4/	Costs Plant ($000)	Costs Common 2/	Costs Total	Pct of Costs	Wtd Capacity Factor 5/
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Scherer 3 (GPC)	Coal	614	4,850,976	5,374,260	90.26%	$460,192	$71,805	$531,997	4.7325%	4.2717%
Vogtle 1 (GPC)	Nuclear	530	4,174,737	4,643,851	89.90%	$1,531,609	$425,395	$1,957,004	17.4090%	15.6503%
Vogtle 2 (GPC)	Nuclear	530	4,638,973	4,643,851	99.89%	$992,708	$275,718	$1,268,426	11.2836%	11.2717%
Wallace	Hydro	209	153,339	1,829,088	8.38%	$189,154	$0	$189,154	1.6827%	0.1411%
Wansley 1 (GPC)	Coal	463	1,908,461	4,053,909	47.08%	$351,615	$23,603	$375,218	3.3378%	1.5714%
Wansley 2 (GPC)	Coal	463	1,888,134	4,053,909	46.58%	$154,975	$10,403	$165,378	1.4712%	0.6852%
Wansley 5A (GPC)	#2 Oil	26	0	230,581	0.00%	$6,965	$0	$6,965	0.0620%	0.0000%
Wilson 1A	#2 Oil	59	142	513,336	0.03%	$5,157	$0	$5,157	0.0459%	0.0000%
Wilson 1B	#2 Oil	59	200	513,336	0.04%	$5,157	$0	$5,157	0.0459%	0.0000%
Wilson 1C	#2 Oil	59	166	513,336	0.03%	$5,157	$0	$5,157	0.0459%	0.0000%
Wilson 1D	#2 Oil	59	26	513,336	0.01%	$5,157	$0	$5,157	0.0459%	0.0000%
Wilson 1E	#2 Oil	59	236	513,336	0.05%	$5,157	$0	$5,157	0.0459%	0.0000%
Wilson 1F	#2 Oil	59	463	513,336	0.09%	$5,157	$0	$5,157	0.0459%	0.0000%
Wilson DS 1	#2 Oil	3	0	21,900	0.00%	$5,157	$0	$5,157	0.0459%	0.0000%
Yates 1	Coal	100	403,689	876,000	46.08%	$26,910	$27,263	$54,173	0.4819%	0.2221%
Yates 2	Coal	100	293,380	876,000	33.49%	$28,079	$28,448	$56,528	0.5029%	0.1684%
Yates 3	Coal	100	372,179	876,000	42.49%	$20,939	$21,214	$42,152	0.3750%	0.1593%
Yates 4	Coal	125	349,686	1,095,000	31.93%	$22,447	$22,741	$45,188	0.4020%	0.1284%
Yates 5	Coal	125	368,167	1,095,000	33.62%	$26,802	$27,154	$53,955	0.4800%	0.1614%
Yates 6	Coal	350	1,457,704	3,066,000	47.54%	$105,670	$17,553	$123,223	1.0962%	0.5212%
Yates 7	Coal	350	1,285,386	3,066,000	41.92%	$119,854	$19,909	$139,763	1.2433%	0.5212%
Total						**$9,183,865**	**$2,057,487**	**$11,241,352**	**100.0000%**	**67.2768384%**

1/ Per Company response to Data Request Staff-Tai-2-9.
2/ Per Company FERC Form 1 (2009).
3/ Calculated as Column (1) times 8760.
4/ Calculated as Column (2) divided by Column (3).
5/ Calculated as Column (4) times Column (8).

Georgia Power Company
Staff Cost of Service Study
BIP Method
Summary

LINE NO.	LINE DESCRIPTION	ELECTRIC SYSTEM	RETAIL SERVICE	ALL OTHER SERVICE	ALLOC	RATE R, RM	RATE TOU-REO	RATE GS	RATE PLS	RATE PLM	RATE PLL	RATE G	RATE SCH	RATE TOU-EO	RATE TOU-GSD
	— RATE BASE —														
1	GROSS PLANT	$26,404,947	$25,406,065	$998,882		$11,847,789	$81,416	$724,705	$1,178,952	$3,717,861	$1,002,399	$43,053	$110,048	$218,511	$110,024
2	ACCUMULATED DEPRECIATION	$10,206,026	$9,725,882	$480,344		$4,459,923	$30,652	$266,639	$442,518	$1,420,091	$387,274	$16,539	$42,078	$82,129	$42,005
3	NUCLEAR FUEL	$524,588	$524,334	$254		$209,110	$1,466	$9,920	$23,483	$88,205	$25,501	$1,100	$2,538	$4,451	$2,540
4	ACCUM. DEPR. OF NUCLEAR FUEL	$208,518	$208,417	$101		$83,119	$583	$3,943	$9,334	$34,266	$10,136	$437	$1,009	$1,769	$1,010
5	NET ELECTRIC PLANT	$16,514,991	$15,996,300	$518,691		$7,513,857	$51,647	$464,043	$750,583	$2,349,710	$630,490	$27,178	$69,499	$139,064	$69,550
	LESS: DEFERRED INCOME TAXES														
6	ACCOUNT 190	-$467,358	-$456,722	-$10,636		-$239,719	-$1,675	-$24,744	-$22,583	-$55,783	-$13,407	-$562	-$1,608	-$4,018	-$1,717
7	ACCOUNT 281 AND 282	$2,984,939	$2,903,529	$81,410		$1,364,578	$9,367	$84,116	$135,223	$422,945	$113,285	$4,875	$12,514	$25,066	$12,533
8	ACCOUNT 283	$378,674	$368,057	$10,617		$179,353	$1,289	$18,566	$18,182	$47,459	$12,021	$507	$1,371	$3,245	$1,443
9	TOTAL DEFERRED INCOME TAX	$2,896,255	$2,814,864	$81,391		$1,304,211	$8,981	$77,938	$130,822	$414,621	$111,899	$4,820	$12,278	$24,293	$12,259
	ADD: OTHER RATE BASE ITEMS														
10	PLANT HELD FOR FUTURE USE	$93,921	$93,869	$52		$42,583	$292	$2,179	$4,727	$15,661	$4,140	$182	$443	$925	$465
11	MATERIALS AND SUPPLIES	$921,677	$855,820	$85,857		$353,662	$2,473	$18,923	$38,668	$136,752	$39,784	$1,711	$4,026	$7,276	$4,036
12	PAYABLES ASSOC. W/ CAP M&S	-$1,077	-$1,077	$0	Plt M&S	-$467	-$3	-$29	-$49	-$165	-$47	-$2	-$5	-$9	-$5
13	MIN BANK BAL, PC, PREPAIDS	$87,094	$85,726	$1,368		$40,268	$277	$2,487	$4,022	$12,592	$3,379	$146	$372	$745	$373
14	PREPAID PENSION ASSET	$516,201	$492,106	$24,095		$247,966	$1,828	$30,782	$25,168	$57,603	$13,668	$568	$1,644	$4,385	$1,774
15	CUSTOMER DEPOSITS	-$257,322	-$257,322	$0	Special	-$101,114	-$724	-$6,905	-$12,977	-$42,801	-$11,813	$0	$0	-$2,415	-$1,383
16	OPERATING RESERVES	-$202,972	-$196,392	-$6,580		-$106,915	-$752	-$13,177	-$10,109	-$22,234	-$4,988	-$206	-$626	-$1,778	-$705
17	DEFERRED MCINTOSH C INSPECTION	$7,200	$7,197	$3	2	$2,870	$20	$138	$322	$1,183	$350	$15	$35	$61	$35
18	DEFERRED NUCLEAR OUT. COSTS	$15,634	$15,626	$8	2	$6,232	$44	$296	$700	$2,569	$760	$33	$76	$133	$76
19	ECCR DEFERRED REG ASSET	$11,581	$11,575	$6	2	$4,616	$32	$219	$518	$1,903	$563	$24	$56	$98	$56
20	ARO REGULATORY ASSET	$796,862	$796,467	$395	ARO asset	$312,698	$2,194	$14,023	$35,529	$132,461	$39,451	$1,704	$3,900	$6,755	$3,899
21	ARO LIABILITY	-$775,594	-$775,211	-$383	ARO asset	-$304,352	-$2,136	-$13,649	-$34,580	-$128,926	-$38,398	-$1,658	-$3,796	-$6,575	-$3,795
22	ARO REGULATORY LIABILITY	-$119,346	-$119,288	-$58	2	-$47,573	-$333	-$2,257	-$5,342	-$19,612	-$5,802	-$250	-$577	-$1,013	-$578
23	REGULATORY ASSET - DEF INC TX	$57,935	$57,914	$21	Headcount	$30,081	$211	$3,402	$2,910	$7,055	$1,700	$71	$201	$517	$220
24	GREEN ENERGY OVER/UNDER REC	$0	$0	$0	36	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	M&S INVENTORY ADJUSTMENT - STEAM	$4,860	$4,858	$2	M&S Prod Plt	$1,937	$14	$92	$218	$799	$238	$10	$24	$41	$24
26	REG LIAB - NON ARO COST OF REMOVAL	-$86,942	-$86,914	-$28		-$44,563	-$303	-$3,031	-$4,028	-$11,346	-$2,831	-$117	-$342	-$724	-$331
27	HAMMOND COOLING TOWER RENTAL	$12,681	$12,675	$6	2	$5,055	$35	$240	$568	$2,084	$618	$27	$61	$108	$61
28	CASH WORKING CAPITAL	$262,258	$246,387	$15,871		$91,169	$655	$6,157	$10,806	$36,569	$10,526	$422	$1,095	$1,990	$1,153
29	TOTAL OTHER RATE BASE ITEMS	$1,344,651	$1,244,016	$100,635		$534,153	$3,825	$39,887	$57,069	$182,146	$51,295	$2,679	$6,587	$10,521	$5,375
30	TOTAL INVESTMENT	$14,963,387	$14,425,452	$537,935		$6,743,799	$46,491	$425,992	$676,830	$2,117,235	$569,887	$25,036	$63,808	$125,291	$62,665
	— REVENUES —														
31	REVENUE FROM SALES	$7,739,600	$7,281,383	$458,217		$2,721,738	$19,489	$185,258	$348,893	$1,152,404	$318,445	$12,051	$35,042	$64,944	$37,211
32	OTHER OPERATING REVENUES	$255,845	$230,255	$25,590		$134,667	$952	$8,673	$9,855	$26,107	$6,583	$296	$779	$1,703	$772
33	TOTAL REVENUES	$7,995,445	$7,511,638	$483,807		$2,856,405	$20,441	$193,931	$358,748	$1,178,512	$325,028	$12,348	$35,821	$66,647	$37,983
	— EXPENSES —														
34	OPERATIONS & MAINTENANCE	$5,942,402	$5,604,435	$594,403		$2,091,954	$14,973	$137,480	$228,247	$788,594	$234,353	$9,937	$23,283	$41,688	$24,093
35	DEPRECIATION EXPENSE	$778,573	$737,917	$40,656		$347,071	$2,368	$22,354	$34,246	$104,884	$27,850	$1,188	$3,115	$6,291	$3,092
36	ARO DEPRECIATION EXPENSE	-$21	-$21	$0		-$2	$0	$1	-$1	-$5	-$2	$0	$0	$0	$0
37	ARO ACCRETION	$48,899	$48,876	$23		$19,570	$137	$941	$2,191	$8,012	$2,366	$102	$236	$415	$236
38	ARO DEFERRAL	-$48,876	-$48,855	-$23		-$19,568	-$137	-$942	-$2,190	-$8,006	-$2,364	-$102	-$236	-$415	-$236
39	NUCLEAR DECOM EXPENSE	$1,686	$1,685	$1	2	$672	$5	$32	$75	$277	$82	$4	$8	$14	$8
40	TAXES OTHER THAN INC. TAX	$166,491	$161,996	$5,293		$75,883	$525	$5,330	$7,604	$23,324	$6,262	$268	$686	$1,402	$695
41	AMORT. OF DEF HEALTHCARE COSTS	$4,165	$4,163	$2		$2,163	$15	$245	$209	$507	$122	$5	$14	$37	$16
42	AMORT. OF HAMMOND COOLING TOWER	$5,415	$5,412	$3	2	$2,159	$15	$102	$242	$890	$263	$11	$26	$46	$26
43	AMORT. DEFERRAL OF ECCR	$7,586	$7,582	$4	2	$3,024	$21	$143	$340	$1,247	$369	$16	$37	$64	$37
44	AMORT. OF M&S INVENTORY ADJ.	$1,080	$1,079	$1		$431	$3	$20	$48	$177	$52	$2	$5	$9	$5
45	AMORT. OF COST OF REMOVAL ADJ.	-$30,825	-$30,815	-$10		-$15,800	-$107	-$1,075	-$1,428	-$4,023	-$1,004	-$41	-$121	-$257	-$117
46	AMORT. OF INV. TAX CREDIT	-$12,202	-$11,583	-$619		-$5,402	-$37	-$330	-$538	-$1,695	-$457	-$20	-$50	-$100	-$50
47	SUBTOTAL EXPENSES	$6,864,371	$6,481,871	$639,734		$2,502,153	$17,800	$184,301	$269,046	$914,182	$267,893	$11,370	$27,003	$49,195	$27,805
48	TOTAL INCOME TAXES	$263,510	$230,637	$3,852		$58,603	$481	$6,512	$26,830	$77,635	$15,477	$88	$2,670	$5,294	$3,208
49	TOTAL EXPENSES	$7,127,881	$6,712,508	$643,586		$2,560,756	$18,281	$170,812	$295,877	$991,816	$283,371	$11,458	$29,673	$54,490	$31,013
	— RETURN —														
50	OPERATING INCOME	$867,564	$799,130	-$159,779		$295,649	$2,159	$23,119	$62,872	$186,695	$41,658	$890	$6,148	$12,157	$6,970
51	INT. ON CUSTOMER DEPOSITS	-$4,271	-$4,271	$0	Cust Deposits	-$1,678	-$12	-$115	-$215	-$710	-$196	$0	$0	-$40	-$23
52	NET INCOME	$663,293	$794,859	-$159,779		$293,971	$2,147	$23,004	$62,656	$185,985	$41,462	$890	$6,148	$12,117	$6,947
53	RETURN ON INVESTMENT	5.77%				4.36%	4.62%	5.40%	9.26%	8.78%	7.28%	3.55%	9.64%	9.67%	11.09%

Georgia Power Company
Staff Cost of Service Study
BIP Method
Summary

LINE NO.	LINE DESCRIPTION	ELECTRIC SYSTEM	RETAIL SERVICE	ALL OTHER SERVICE	ALLOC	RATE TOU-SSD	RATE TOU-MAM	RATE TOU-MLM	RATE TOU - SC	RATE TOU-HLF	RATE TOU-HLF	RATE RTP-DA	RATE RTP-HA	RATE SLM	RATE OLG
	--- RATE BASE ---														
1	GROSS PLANT	$26,404,947	$25,408,065	$996,882		$9,603	$2,608	$116,028	$98,974	$29,361	$182,665	$2,255,920	$1,285,977	$587,508	$321,130
2	ACCUMULATED DEPRECIATION	$10,206,026	$9,725,682	$480,344		$3,791	$1,002	$45,299	$39,114	$11,372	$62,396	$870,795	$508,957	$224,698	$163,216
3	NUCLEAR FUEL	$524,588	$524,334	$254		$268	$62	$3,329	$3,060	$741	$3,612	$55,721	$39,027	$13,715	$2,173
4	ACCUM. DEPR. OF NUCLEAR FUEL	$208,518	$208,417	$101		$107	$24	$1,323	$1,216	$295	$1,515	$22,149	$15,513	$5,451	$864
5	NET ELECTRIC PLANT	$16,514,991	$15,996,300	$518,691		$5,973	$1,643	$72,734	$61,794	$18,436	$102,568	$1,418,698	$800,535	$371,072	$159,223
	LESS: DEFERRED INCOME TAXES														
6	ACCOUNT 190	-$467,358	-$456,722	-$10,636		-$126	-$35	-$1,458	-$1,173	-$388	-$2,360	-$31,307	-$15,593	-$8,043	-$6,092
7	ACCOUNT 281 AND 282	$2,984,939	$2,903,529	$81,410		$1,072	$296	$13,006	$11,002	$3,315	$18,455	$255,251	$142,961	$66,844	$37,334
8	ACCOUNT 283	$378,674	$368,057	$10,617		$120	$30	$1,415	$1,202	$347	$2,030	$29,518	$17,233	$6,894	$4,671
9	TOTAL DEFERRED INCOME TAX	$2,896,255	$2,814,884	$81,391		$1,065	$291	$12,983	$11,031	$3,274	$16,126	$253,460	$144,601	$65,695	$35,913
	ADD: OTHER RATE BASE ITEMS														
10	PLANT HELD FOR FUTURE USE	$93,921	$93,869	$52		$33	$11	$453	$439	$117	$839	$8,467	$4,826	$2,533	$21
11	MATERIALS AND SUPPLIES	$921,677	$855,820	$65,857		$415	$97	$5,106	$4,655	$1,159	$8,039	$87,429	$59,577	$21,639	$4,967
12	PAYABLES ASSOC. W/ CAP M&S	-$1,077	-$1,077	$0	Plt M&S	$0	$0	-$6	-$5	-$1	-$7	-$104	-$67	-$26	-$9
13	MIN BANK BAL, PC, PREPAIDS	$67,094	$85,726	$1,368		$32	$9	$390	$331	$99	$550	$7,603	$4,290	$1,989	$853
14	PREPAID PENSION ASSET	$516,201	$492,106	$24,095		$137	$34	$1,582	$1,304	$391	$2,433	$37,034	$21,149	$7,875	$7,435
15	CUSTOMER DEPOSITS	-$257,322	-$257,322	$0	Special	-$137	-$28	-$1,447	-$1,064	-$312	-$1,694	-$34,882	-$24,906	$0	$0
16	OPERATING RESERVES	-$202,972	-$196,392	-$6,580		-$46	-$13	-$529	-$409	-$142	-$915	-$11,833	-$5,456	-$3,007	-$2,458
17	DEFERRED MCINTOSH C INSPECTION	$7,200	$7,197	$3	2	$4	$1	$46	$42	$10	$52	$765	$536	$188	$30
18	DEFERRED NUCLEAR OUT. COSTS	$15,634	$15,826	$8	2	$8	$2	$99	$91	$22	$114	$1,861	$1,163	$409	$85
19	ECCR DEFERRED REG ASSET	$11,581	$11,575	$6	2	$6	$1	$73	$68	$16	$84	$1,230	$862	$303	$48
20	ARO REGULATORY ASSET	$796,862	$796,467	$395	ARO asset	$417	$95	$5,183	$4,782	$1,147	$5,864	$86,022	$60,928	$21,116	$2,794
21	ARO LIABILITY	-$775,594	-$775,211	-$383	ARO asset	-$405	-$92	-$5,045	-$4,654	-$1,116	-$5,707	-$83,726	-$59,302	-$20,552	-$2,719
22	ARO REGULATORY LIABILITY	-$119,346	-$119,288	-$58	2	-$61	-$14	-$757	-$696	-$169	-$867	-$12,677	-$8,879	-$3,120	-$494
23	REGULATORY ASSET - DEF INC TX	$57,935	$57,914	$21	Headcount	$16	$4	$192	$156	$49	$296	$3,947	$2,075	$993	$860
24	GREEN ENERGY OVER/UNDER REC	$0	$0	$0	36	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	M&S INVENTORY ADJUSTMENT - STEAM	$4,860	$4,858	$2	M&S Prod Plt	$2	$1	$31	$28	$7	$35	$518	$362	$127	$20
26	REG LIAB - NON ARO COST OF REMOVAL	-$66,942	-$66,914	-$28		-$27	-$8	-$280	-$223	-$86	-$507	-$6,642	-$3,068	-$1,777	-$1,925
27	HAMMOND COOLING TOWER RENTAL	$12,681	$12,675	$6	2	$6	$1	$80	$74	$16	$92	$1,347	$943	$332	$53
28	CASH WORKING CAPITAL	$262,258	$246,387	$15,871		$118	$25	$1,380	$1,065	$293	$1,492	$32,900	$25,557	$5,033	$1,920
29	TOTAL OTHER RATE BASE ITEMS	$1,344,651	$1,244,016	$100,635		$518	$126	$6,551	$5,985	$1,502	$7,992	$119,077	$80,589	$34,054	$11,259
30	TOTAL INVESTMENT	$14,963,387	$14,425,452	$537,935		$5,425	$1,478	$66,322	$56,658	$16,664	$92,432	$1,284,315	$736,522	$339,431	$134,570
	— REVENUES ---														
31	REVENUE FROM SALES	$7,739,600	$7,281,383	$458,217		$3,705	$761	$39,064	$28,810	$8,418	$45,686	$937,861	$663,476	$142,034	$68,444
32	OTHER OPERATING REVENUES	$255,845	$230,255	$25,590		$53	$17	$750	$592	$187	$1,103	$14,702	$7,551	$4,041	$1,417
33	TOTAL REVENUES	$7,995,445	$7,511,638	$483,807		$3,759	$779	$39,813	$29,402	$8,603	$46,769	$952,563	$691,027	$146,076	$69,861
	— EXPENSES ---														
34	OPERATIONS & MAINTENANCE	$5,942,402	$5,804,435	$594,403		$2,509	$557	$32,093	$25,905	$8,868	$33,353	$749,895	$601,283	$121,709	$41,410
35	DEPRECIATION EXPENSE	$778,573	$737,917	$40,656		$267	$73	$3,158	$2,664	$820	$4,613	$63,191	$34,970	$16,488	$14,476
36	ARO DEPRECIATION EXPENSE	-$21	-$21	$0		$0	$0	$0	$0	$0	$0	-$4	-$4	-$1	$1
37	ARO ACCRETION	$48,699	$48,876	$23		$25	$6	$308	$283	$69	$354	$5,172	$3,612	$1,274	$211
38	ARO DEFERRAL	-$48,878	-$48,855	-$23		-$25	-$6	-$308	-$283	-$69	-$354	-$5,168	-$3,608	-$1,273	-$211
39	NUCLEAR DECOM EXPENSE	$1,686	$1,685	$1	2	$1	$0	$11	$10	$2	$12	$179	$125	$44	$7
40	TAXES OTHER THAN INC. TAX	$166,491	$161,996	$5,293		$61	$16	$735	$631	$183	$1,015	$14,097	$8,193	$3,627	$1,853
41	AMORT. OF DEF HEALTHCARE COSTS	$4,165	$4,163	$2		$1	$0	$14	$11	$4	$21	$284	$149	$71	$47
42	AMORT. OF HAMMOND COOLING TOWER	$5,415	$5,412	$3	2	$3	$1	$34	$32	$8	$39	$575	$403	$142	$22
43	AMORT. DEFERRAL OF ECCR	$7,588	$7,582	$4	2	$4	$1	$48	$44	$11	$55	$806	$564	$198	$31
44	AMORT. OF M&S INVENTORY ADJ.	$1,080	$1,079	$1		$1	$0	$7	$6	$2	$8	$115	$80	$28	$4
45	AMORT. OF COST OF REMOVAL ADJ.	-$30,825	-$30,815	-$10		-$10	-$3	-$99	-$79	-$30	-$180	-$2,355	-$1,088	-$630	-$682
46	AMORT. OF INV. TAX CREDIT	-$12,202	-$11,583	-$619		-$4	-$1	-$53	-$45	-$13	-$74	-$1,029	-$586	-$268	-$146
47	SUBTOTAL EXPENSES	$6,864,371	$6,481,671	$639,734		$2,632	$645	$35,948	$29,160	$7,853	$38,863	$825,759	$644,094	$141,409	$57,023
48	TOTAL INCOME TAXES	$263,510	$230,637	$3,652		$296	$35	$725	-$572	$97	$1,991	$34,136	$9,617	-$2,140	$3,386
49	TOTAL EXPENSES	$7,127,881	$6,712,508	$643,586		$3,128	$679	$36,672	$28,606	$7,950	$40,854	$859,897	$653,710	$139,269	$60,409
	--- RETURN ---														
50	OPERATING INCOME	$867,564	$799,130	-$159,779		$630	$99	$3,141	$794	$654	$5,935	$92,666	$37,317	$6,807	$9,452
51	INT. ON CUSTOMER DEPOSITS	-$4,271	-$4,271	$0	Cust Deposits	-$2	$0	-$24	-$18	-$5	-$28	-$579	-$413	$0	$0
52	NET INCOME	$863,293	$794,859	-$159,779		$628	$99	$3,117	$777	$649	$5,907	$92,087	$36,903	$6,807	$9,452
53	RETURN ON INVESTMENT	5.77%				11.58%	6.67%	4.70%	1.37%	3.89%	6.39%	7.17%	5.01%	2.01%	7.02%

Georgia Power Company
Staff Cost of Service Study
BIP Method
Summary

LINE NO.	LINE DESCRIPTION	ELECTRIC SYSTEM	RETAIL SERVICE	ALL OTHER SERVICE	ALLOC	RATE OLNG	RATE EOL	RATE UC	RATE FPA	RATE TC	RATE APS, TOU-FS, IOP	RATE SAS	RATE OGS
	— RATE BASE —												
1	GRDSS PLANT	$26,404,947	$25,406,065	$998,882		$186,129	$90,215	$27,910	$1,094,986	$16,419	$72,512	$9,830	$3,792
2	ACCUMULATED DEPRECIATION	$10,206,026	$9,725,682	$480,344		$92,102	$36,356	$10,833	$427,260	$6,370	$27,254	$3,704	$1,433
3	NUCLEAR FUEL	$524,588	$524,334	$254		$1,354	$1,967	$533	$30,736	$384	$952	$154	$43
4	ACCUM. DEPR. OF NUCLEAR FUEL	$208,518	$208,417	$101		$538	$782	$212	$12,217	$153	$378	$61	$17
5	NET ELECTRIC PLANT	$16,514,991	$15,996,300	$518,691		$94,843	$55,044	$17,398	$686,246	$10,281	$45,831	$6,219	$2,385
	LESS: DEFERRED INCOME TAXES												
6	ACCOUNT 190	-$467,358	-$456,722	-$10,636		-$4,640	-$2,335	-$1,093	-$14,098	-$339	-$1,427	-$236	-$167
7	ACCOUNT 281 AND 282	$2,984,939	$2,903,529	$81,410		$21,611	$10,057	$3,180	$122,889	$1,859	$8,393	$1,133	$439
8	ACCOUNT 283	$378,674	$368,057	$10,617		$3,499	$1,866	$831	$13,381	$277	$1,017	$178	$122
9	TOTAL DEFERRED INCOME TAX	$2,896,255	$2,814,884	$81,391		$20,470	$9,589	$2,919	$122,172	$1,797	$7,983	$1,074	$394
	ADD: OTHER RATE BASE ITEMS												
10	PLANT HELD FOR FUTURE USE	$93,921	$93,869	$52		$13	$18	$69	$4,352	$58	$172	$27	$6
11	MATERIALS AND SUPPLIES	$921,677	$855,820	$65,857		$3,131	$3,321	$953	$47,322	$621	$1,731	$273	$92
12	PAYABLES ASSOC. W/ CAP M&S	-$1,077	-$1,077	$0	Plt M&S	-$8	-$4	-$1	-$54	-$1	-$2	$0	$0
13	MIN BANK BAL, PC, PREPAIDS	$87,094	$85,726	$1,368		$508	$295	$93	$3,678	$55	$246	$33	$13
14	PREPAID PENSION ASSET	$516,201	$492,106	$24,095		$5,810	$2,852	$1,383	$15,023	$386	$1,418	$268	$209
15	CUSTOMER DEPOSITS	-$257,322	-$257,322	$0	Special	$0	$0	-$444	-$11,733	$0	-$429	-$69	-$45
16	OPERATING RESERVES	-$202,972	-$196,392	-$6,580		-$2,158	-$1,153	-$599	-$5,194	-$157	-$624	-$115	-$95
17	DEFERRED MCINTOSH C INSPECTION	$7,200	$7,197	$3	2	$19	$27	$7	$422	$5	$13	$2	$1
18	DEFERRED NUCLEAR OUT. COSTS	$15,834	$15,626	$8	2	$40	$59	$16	$916	$11	$28	$5	$1
19	ECCR DEFERRED REG ASSET	$11,581	$11,575	$6	2	$30	$43	$12	$679	$8	$21	$3	$1
20	ARO REGULATORY ASSET	$796,862	$796,467	$395	**ARO asset**	$1,727	$2,963	$778	$47,800	$586	$1,381	$226	$57
21	ARO LIABILITY	-$775,594	-$775,211	-$383	**ARO asset**	-$1,681	-$2,884	-$758	-$46,524	-$571	-$1,344	-$220	-$55
22	ARO REGULATORY LIABILITY	-$119,346	-$119,288	-$58	2	-$308	-$448	-$121	-$6,993	-$87	-$217	-$35	-$10
23	REGULATORY ASSET - DEF INC TX	$57,935	$57,914	$21	Headcount	$562	$322	$156	$1,847	$46	$172	$31	$24
24	GREEN ENERGY OVER/UNDER REC	$0	$0	$0	36	$0	$0	$0	$0	$0	$0	$0	$0
25	M&S INVENTORY ADJUSTMENT - STEAM	$4,860	$4,858	$2	M&S Prod Plt	$13	$18	$5	$285	$4	$9	$1	$0
26	REG LIAB - NON ARO COST OF REMOVAL	-$86,942	-$86,914	-$28		-$1,089	-$375	-$102	-$2,743	-$51	-$337	-$41	-$18
27	HAMMOND COOLING TOWER RENTAL	$12,681	$12,675	$6	2	$33	$48	$13	$743	$9	$23	$4	$1
28	CASH WORKING CAPITAL	$262,258	$246,387	$15,871		$1,336	$1,202	$377	$11,485	$136	$415	$71	$38
29	TOTAL OTHER RATE BASE ITEMS	$1,344,651	$1,244,016	$100,635		$7,980	$6,306	$1,837	$61,309	$1,057	$2,676	$463	$221
30	TOTAL INVESTMENT	$14,963,387	$14,425,452	$537,935		$82,353	$51,761	$16,316	$825,383	$9,541	$40,524	$5,608	$2,211
	— REVENUES —												
31	REVENUE FROM SALES	$7,739,600	$7,281,383	$458,217		$46,023	$34,898	$11,905	$317,263	$2,920	$11,553	$1,872	$1,218
32	OTHER OPERATING REVENUES	$255,845	$230,255	$25,590		$910	$378	$463	$7,029	$112	$471	$65	$26
33	TOTAL REVENUES	$7,995,445	$7,511,638	$483,807		$46,934	$35,276	$12,369	$324,291	$3,032	$12,024	$1,937	$1,244
	— EXPENSES —												
34	OPERATIONS & MAINTENANCE	$5,942,402	$5,604,435	$594,403		$28,403	$27,226	$7,564	$275,535	$3,889	$10,770	$1,826	$797
35	DEPRECIATION EXPENSE	$778,573	$737,917	$40,656		$8,106	$2,742	$823	$29,932	$466	$2,237	$298	$120
36	ARO DEPRECIATION EXPENSE	-$21	-$21	$0		$0	$0	$0	-$3	$0	$0	$0	$0
37	ARO ACCRETION	$48,899	$48,876	$23		$131	$184	$50	$2,848	$36	$90	$14	$4
38	ARO DEFERRAL	-$48,878	-$48,855	-$23		-$132	-$184	-$50	-$2,845	-$36	-$90	-$14	-$4
39	NUCLEAR DECOM EXPENSE	$1,686	$1,685	$1	2	$4	$6	$2	$99	$1	$3	$0	$0
40	TAXES OTHER THAN INC. TAX	$166,491	$161,996	$5,293		$1,168	$638	$223	$6,931	$110	$447	$65	$31
41	AMDRT. OF DEF HEALTHCARE COSTS	$4,185	$4,163	$2		$40	$23	$11	$133	$3	$12	$2	$2
42	AMORT. OF HAMMOND COOLING TOWER	$5,415	$5,412	$3	2	$14	$20	$6	$317	$4	$10	$2	$0
43	AMORT. DEFERRAL OF ECCR	$7,586	$7,582	$4	2	$20	$28	$8	$444	$6	$14	$2	$1
44	AMORT. OF M&S INVENTORY ADJ.	$1,080	$1,079	$1		$3	$4	$1	$63	$1	$2	$0	$0
45	AMORT. OF COST OF REMOVAL ADJ.	-$30,825	-$30,815	-$10		-$386	-$133	-$36	-$973	-$18	-$119	-$15	-$6
46	AMORT. OF INV. TAX CREDIT	-$12,202	-$11,583	-$619		-$85	-$41	-$13	-$499	-$7	-$33	-$4	-$2
47	SUBTOTAL EXPENSES	$8,864,371	$6,481,871	$639,734		$37,287	$30,511	$8,588	$311,982	$4,454	$13,343	$2,177	$943
48	TOTAL INCOME TAXES	$263,510	$230,637	$3,852		$2,787	$1,241	$1,273	-$2,505	-$661	-$982	-$159	$91
49	TOTAL EXPENSES	$7,127,881	$6,712,508	$643,586		$40,054	$31,753	$9,861	$309,477	$3,793	$12,361	$2,019	$1,034
	— RETURN —												
50	OPERATING INCOME	$867,564	$799,130	-$159,779		$6,880	$3,523	$2,508	$14,815	-$761	-$337	-$81	$211
51	INT. ON CUSTOMER DEPOSITS	-$4,271	-$4,271	$0	Cust Deposits	$0	$0	-$7	-$195	$0	-$7	-$1	-$1
52	NET INCOME	$863,293	$794,859	-$159,779		$6,880	$3,523	$2,501	$14,620	-$761	-$344	-$82	$210
53	RETURN ON INVESTMENT	5.77%				8.35%	6.81%	15.33%	2.34%	-7.98%	-0.85%	-1.47%	9.50%

Georgia Power Company
Staff Cost of Service Study
BIP Method
Summary

LINE NO.	LINE DESCRIPTION	ELECTRIC SYSTEM	RETAIL SERVICE	ALL OTHER SERVICE	ALLOC	DOMESTIC	SMALL BUSINESS	MEDIUM BUSINESS	LARGE BUSINESS	AGRICULTURAL	GOVERNMENT/ INSTITUTION	LIGHTING	MARGINAL
	— RATE BASE —												
1	GROSS PLANT	$26,404,947	$25,406,065	$998,882		11,946,606	2,151,511	3,995,863	1,157,085	67,943	758,046	596,445	4,732,823
2	ACCUMULATED DEPRECIATION	$10,206,026	$9,725,682	$480,344		4,497,002	802,680	1,526,494	447,631	25,637	290,059	291,293	1,845,000
3	NUCLEAR FUEL	$524,588	$524,334	$254		210,575	38,430	92,619	29,639	1,106	17,737	5,494	128,544
4	ACCUM. DEPR. OF NUCLEAR FUEL	$208,518	$208,417	$101		83,701	15,276	36,815	11,861	439	7,050	2,184	51,095
5	NET ELECTRIC PLANT	$16,514,991	$15,996,300	$518,691		7,576,478	1,371,986	2,525,174	727,432	42,972	478,675	308,462	2,965,272
	LESS: DEFERRED INCOME TAXES												
6	ACCOUNT 190	-$467,358	-$456,722	-$10,636		-241,735	-52,558	-59,948	-15,373	-1,381	-10,572	-13,047	-61,928
7	ACCOUNT 281 AND 282	$2,984,939	$2,903,529	$81,410		1,376,006	247,745	454,550	130,641	7,820	86,214	68,881	531,744
8	ACCOUNT 283	$378,674	$368,057	$10,617		180,829	40,921	50,991	13,898	1,040	9,060	10,025	57,816
9	TOTAL DEFERRED INCOME TAX	$2,896,255	$2,814,864	$81,391		1,315,099	236,108	445,594	129,166	7,479	84,702	65,859	527,632
	ADD: OTHER RATE BASE ITEMS												
10	PLANT HELD FOR FUTURE USE	$93,921	$93,869	$52		42,875	7,905	16,776	4,743	199	3,215	52	18,105
11	MATERIALS AND SUPPLIES	$921,677	$855,820	$65,857		356,244	65,897	146,941	46,462	1,913	28,004	11,412	198,964
12	PAYABLES ASSOC. W/ CAP M&S	-$1,077	-$1,077	$0	Plt M&S	-471	-89	-177	-54	-3	-34	-19	-231
13	MIN BANK BAL, PC, PREPAIDS	$87,094	$85,726	$1,368		40,603	7,353	13,533	3,898	230	2,565	1,653	15,891
14	PREPAID PENSION ASSET	$516,201	$492,106	$24,095		250,057	61,892	61,885	15,770	1,468	10,490	16,082	65,700
15	CUSTOMER DEPOSITS	-$257,322	-$257,322	$0	Special	-101,838	-22,786	-45,906	-13,709	-498	0	0	-72,585
16	OPERATING RESERVES	-$202,972	-$196,392	-$6,580		-107,805	-25,738	-23,888	-5,704	-625	-4,005	-5,760	-22,867
17	DEFERRED MCINTOSH C INSPECTION	$7,200	$7,197	$3	2	$2,890	$527	$1,271	$410	$15	$243	$75	$1,764
18	DEFERRED NUCLEAR OUT. COSTS	$15,634	$15,626	$8	2	$6,276	$1,145	$2,760	$889	$33	$529	$164	$3,831
19	ECCR DEFERRED REG ASSET	$11,581	$11,575	$6	2	$4,649	$848	$2,045	$659	$24	$392	$121	$2,838
20	ARO REGULATORY ASSET	$796,862	$796,467	$395	ARO asset	314,852	57,147	142,313	46,198	1,640	27,304	7,486	199,538
21	ARO LIABILITY	-$775,594	-$775,211	-$383	ARO asset	-306,449	-55,622	-138,515	-44,965	-1,596	-26,575	-7,286	-194,213
22	ARO REGULATORY LIABILITY	-$119,346	-$119,288	-$58	2	($47,907)	($8,743)	($21,071)	($6,788)	($252)	($4,035)	($1,250)	($29,244)
23	REGULATORY ASSET - DEF INC TX	$57,935	$57,914	$21	Headcount	$30,327	$7,004	$7,580	$1,957	$174	$1,313	$1,543	$8,020
24	GREEN ENERGY OVER/UNDER REC	$0	$0	$0	36	$0	$0	$0	$0	$0	$0	$0	$0
25	M&S INVENTORY ADJUSTMENT - STEAM	$4,860	$4,858	$2	M&S Prod Plt	$1,951	$356	$858	$276	$10	$164	$51	$1,191
26	REG LIAB - NON ARO COST OF REMOVAL	-$86,942	-$86,914	-$28		-44,983	-7,886	-12,211	-3,221	-280	-2,293	-3,382	-12,657
27	HAMMOND COOLING TOWER RENTAL	$12,681	$12,675	$6	2	$5,090	$929	$2,239	$721	$27	$429	$133	$3,107
28	CASH WORKING CAPITAL	$262,258	$246,387	$15,871		91,831	19,367	39,241	12,316	479	6,686	4,458	71,336
29	TOTAL OTHER RATE BASE ITEMS	$1,344,651	$1,244,016	$100,635		538,194	109,507	195,674	59,857	2,959	44,391	25,533	258,489
30	TOTAL INVESTMENT	$14,963,387	$14,425,452	$537,935		6,799,572	1,245,385	2,275,254	658,123	38,452	438,363	268,136	2,696,130
	— REVENUES —												
31	REVENUE FROM SALES	$7,739,600	$7,281,383	$458,217		2,741,227	612,219	1,236,061	369,631	13,427	192,046	149,366	1,967,413
32	OTHER OPERATING REVENUES	$255,845	$230,255	$25,590		135,703	20,710	28,013	7,572	467	5,234	2,701	29,859
33	TOTAL REVENUES	$7,995,445	$7,511,638	$483,807		2,876,929	632,928	1,264,074	377,203	13,894	197,279	152,066	1,997,272
	— EXPENSES —												
34	OPERATIONS & MAINTENANCE	$5,942,402	$5,604,435	$594,403		2,107,734	415,668	846,764	275,803	11,929	158,867	96,991	1,664,871
35	DEPRECIATION EXPENSE	$778,573	$737,917	$40,656		350,051	63,753	112,754	32,085	2,045	21,291	25,289	130,654
36	ARO DEPRECIATION EXPENSE	-$21	-$21	$0		-2	0	-6	-2	0	-1	1	-10
37	ARO ACCRETION	$48,899	$48,876	$23		19,708	3,601	8,608	2,768	104	1,648	526	11,915
38	ARO DEFERRAL	-$48,878	-$48,855	-$23		-19,705	-3,601	-8,602	-2,765	-104	-1,647	-527	-11,904
39	NUCLEAR DECOM EXPENSE	$1,686	$1,685	$1	2	$677	$124	$298	$96	$4	$57	$18	$413
40	TAXES OTHER THAN INC. TAX	$166,491	$161,996	$5,293		76,503	14,576	25,066	7,239	433	4,698	3,651	29,836
41	AMORT. OF DEF HEALTHCARE COSTS	$4,165	$4,163	$2		2,180	504	545	141	13	94	111	577
42	AMORT. OF HAMMOND COOLING TOWER	$5,415	$5,412	$3	2	$2,174	$397	$956	$308	$11	$183	$57	$1,327
43	AMORT. DEFERRAL OF ECCR	$7,586	$7,582	$4	2	$3,045	$556	$1,339	$431	$16	$256	$79	$1,859
44	AMORT. OF M&S INVENTORY ADJ.	$1,080	$1,079	$1		434	79	191	61	2	37	11	265
45	AMORT. OF COST OF REMOVAL ADJ.	-$30,825	-$30,815	-$10		-15,949	-2,796	-4,329	-1,142	-99	-813	-1,199	-4,487
46	AMORT. OF INV. TAX CREDIT	-$12,202	-$11,583	-$619		-5,447	-981	-1,822	-528	-31	-346	-272	-2,158
47	SUBTOTAL EXPENSES	$6,864,371	$6,481,871	$639,734		2,521,402	491,878	981,762	314,494	14,323	184,325	124,735	1,823,156
48	TOTAL INCOME TAXES	$263,510	$230,637	$3,852		58,448	40,086	82,754	16,609	-614	-83	7,433	36,055
49	TOTAL EXPENSES	$7,127,881	$6,712,508	$643,586		2,579,850	531,965	1,064,515	331,103	13,709	184,241	132,168	1,859,210
	— RETURN —												
50	OPERATING INCOME	$867,564	$799,130	-$159,779		297,079	100,964	199,559	46,100	185	13,038	19,898	138,062
51	INT. ON CUSTOMER DEPOSITS	-$4,271	-$4,271	$0	Cust Deposits	-1,690	-378	-762	-228	-8	0	0	-1,205
52	NET INCOME	$863,293	$794,859	-$159,779		295,389	100,585	198,797	45,872	177	13,038	19,898	136,857
53	RETURN ON INVESTMENT	5.77%				4.34%	8.08%	8.74%	6.97%	0.46%	2.97%	7.42%	5.08%

Georgia Power Company
Staff Cost of Service Study
Peak Average Method
Summary

LINE NO.	LINE DESCRIPTION	ELECTRIC SYSTEM	RETAIL SERVICE	ALL OTHER SERVICE	ALLOC	RATE R, RM	RATE TOU-REO	RATE GS	RATE PLS	RATE PLM	RATE PLL	RATE G	RATE SCH	RATE TOU-EO
	— RATE BASE —													
1	GROSS PLANT	$28,404,947	$25,406,065	$998,882		$11,933,889	$81,914	$731,779	$1,188,151	$3,722,724	$985,254	$42,828	$109,839	$220,709
2	ACCUMULATED DEPRECIATION	$10,206,026	$9,725,682	$480,344		$4,497,218	$30,868	$269,710	$448,512	$1,422,202	$384,171	$16,441	$41,987	$83,084
3	NUCLEAR FUEL	$524,568	$524,334	$254		$212,722	$1,487	$10,218	$23,870	$86,410	$25,200	$1,091	$2,529	$4,544
4	ACCUM. DEPR. OF NUCLEAR FUEL	$208,518	$208,417	$101		$84,555	$591	$4,061	$9,488	$34,347	$10,017	$434	$1,005	$1,806
5	NET ELECTRIC PLANT	$16,514,991	$15,996,300	$518,691		$7,584,639	$51,942	$468,225	$756,021	$2,352,585	$626,266	$27,044	$69,376	$140,364
	LESS: DEFERRED INCOME TAXES													
6	ACCOUNT 190	($467,358)	($456,722)	($10,638)		($240,549)	($1,680)	($24,812)	($22,672)	($55,830)	($13,338)	($560)	($1,606)	($4,039)
7	ACCOUNT 281 AND 282	$2,984,939	$2,903,529	$81,410		$1,373,537	$9,419	$84,854	$136,182	$423,452	$112,540	$4,852	$12,493	$25,295
8	ACCOUNT 283	$378,674	$388,057	$10,617		$180,506	$1,298	$18,661	$18,306	$47,524	$11,925	$504	$1,368	$3,275
9	TOTAL DEFERRED INCOME TAX	$2,896,255	$2,814,864	$81,391		$1,313,494	$9,035	$78,703	$131,816	$415,147	$111,126	$4,798	$12,255	$24,531
	ADD: OTHER RATE BASE ITEMS													
10	PLANT HELD FOR FUTURE USE	$93,921	$93,889	$52		$42,583	$292	$2,179	$4,727	$15,661	$4,140	$182	$443	$925
11	MATERIALS AND SUPPLIES	$921,677	$855,820	$65,857		$359,065	$2,504	$19,388	$39,247	$137,057	$39,334	$1,697	$4,013	$7,414
12	PAYABLES ASSOC. W/ CAP M&S	($1,077)	($1,077)	$0	Plt M&S	($473)	($3)	($29)	($50)	($165)	($46)	($2)	($5)	($9)
13	MIN BANK BAL, PC, PREPAIDS	$87,094	$85,728	$1,368		$40,540	$278	$2,509	$4,052	$12,808	$3,356	$145	$372	$752
14	PREPAID PENSION ASSET	$518,201	$492,106	$24,095		$249,236	$1,835	$30,888	$25,304	$57,675	$13,562	$564	$1,641	$4,417
15	CUSTOMER DEPOSITS	($257,322)	($257,322)	$0	Special	($101,114)	($724)	($6,905)	($12,977)	($42,801)	($11,813)	$0	$0	($2,415)
16	OPERATING RESERVES	($202,972)	($196,392)	($6,580)		($107,148)	($753)	($13,196)	($10,134)	($22,247)	($4,969)	($206)	($626)	($1,784)
17	DEFERRED MCINTOSH C INSPECTION	$7,200	$7,197	$3	2	$2,920	$20	$140	$328	$1,166	$346	$15	$35	$62
18	DEFERRED NUCLEAR OUT. COSTS	$15,634	$15,626	$8	2	$6,340	$44	$305	$711	$2,575	$751	$33	$75	$135
19	ECCR DEFERRED REG ASSET	$11,581	$11,575	$6	2	$4,696	$33	$226	$527	$1,908	$556	$24	$56	$100
20	ARO REGULATORY ASSET	$796,862	$796,467	$395	ARO asset	$318,402	$2,228	$14,493	$36,139	$132,784	$38,977	$1,689	$3,886	$6,901
21	ARO LIABILITY	($775,594)	($775,211)	($383)	ARO asset	($309,904)	($2,169)	($14,106)	($35,175)	($129,240)	($37,936)	($1,644)	($3,782)	($6,717)
22	ARO REGULATORY LIABILITY	($119,346)	($119,288)	($58)	2	($48,395)	($338)	($2,325)	($5,431)	($19,659)	($5,733)	($248)	($575)	($1,034)
23	REGULATORY ASSET - DEF INC TX	$57,935	$57,914	$21	Headcount	$30,212	$212	$3,412	$2,924	$7,062	$1,689	$71	$201	$521
24	GREEN ENERGY OVER/UNDER REC	$0	$0	$0	36	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	M&S INVENTORY ADJUSTMENT - STEAM	$4,880	$4,858	$2	M&S Prod Plt	$1,971	$14	$95	$221	$801	$233	$10	$23	$42
26	REG LIAB - NON ARO COST OF REMOVAL	($68,942)	($68,914)	($28)		($44,782)	($304)	($3,048)	($4,049)	($11,358)	($2,814)	($116)	($341)	($729)
27	HAMMOND COOLING TOWER RENTAL	$12,681	$12,675	$6	2	$5,142	$36	$247	$577	$2,089	$609	$26	$81	$110
28	CASH WORKING CAPITAL	$262,258	$246,387	$15,871		$91,268	$858	$6,167	$10,619	$36,576	$10,516	$421	$1,095	$1,993
29	TOTAL OTHER RATE BASE ITEMS	$1,344,651	$1,244,016	$100,635		$540,597	$3,861	$40,418	$57,760	$182,512	$50,759	$2,662	$6,572	$10,686
30	TOTAL INVESTMENT	$14,963,387	$14,425,452	$537,935		$6,791,741	$46,769	$429,940	$681,964	$2,119,950	$565,898	$24,910	$63,692	$126,518
	— REVENUES —													
31	REVENUE FROM SALES	$7,739,600	$7,281,383	$458,217		$2,721,785	$19,489	$185,262	$348,898	$1,152,407	$318,441	$12,051	$35,042	$64,945
32	OTHER OPERATING REVENUES	$255,845	$230,255	$25,590		$134,719	$952	$8,677	$9,861	$26,110	$6,579	$298	$779	$1,705
33	TOTAL REVENUES	$7,995,445	$7,511,638	$483,807		$2,856,504	$20,441	$193,939	$358,759	$1,178,517	$325,020	$12,347	$35,621	$66,649
	— EXPENSES —													
34	OPERATIONS & MAINTENANCE	$5,942,402	$5,604,435	$594,403		$2,098,974	$15,013	$138,058	$228,999	$786,992	$233,769	$9,919	$23,266	$41,868
35	DEPRECIATION EXPENSE	$778,573	$737,917	$40,656		$349,444	$2,402	$22,549	$34,500	$105,018	$27,652	$1,181	$3,109	$6,351
36	ARO DEPRECIATION EXPENSE	($21)	($21)	$0		($3)	$0	$1	($1)	($5)	($2)	$0	$0	$0
37	ARO ACCRETION	$48,899	$48,876	$23		$19,903	$139	$968	$2,227	$8,031	$2,338	$101	$235	$424
38	ARO DEFERRAL	($48,878)	($48,855)	($23)		($19,900)	($139)	($969)	($2,226)	($8,025)	($2,336)	($101)	($235)	($423)
39	NUCLEAR DECOM EXPENSE	$1,688	$1,685	$1	2	$684	$5	$33	$77	$278	$81	$4	$8	$15
40	TAXES OTHER THAN INC. TAX	$166,491	$161,998	$5,293		$76,456	$528	$5,377	$7,668	$23,356	$6,215	$267	$884	$1,417
41	AMORT. OF DEF HEALTHCARE COSTS	$4,165	$4,163	$2		$2,172	$15	$245	$210	$508	$121	$5	$14	$37
42	AMORT. OF HAMMOND COOLING TOWER	$5,415	$5,412	$3	2	$2,196	$15	$105	$246	$892	$260	$11	$26	$47
43	AMORT. DEFERRAL OF ECCR	$7,586	$7,582	$4	2	$3,078	$21	$148	$345	$1,250	$364	$16	$37	$66
44	AMORT. OF M&S INVENTORY ADJ.	$1,080	$1,079	$1		$438	$3	$21	$49	$178	$52	$2	$5	$9
45	AMORT. OF COST OF REMOVAL ADJ.	($30,825)	($30,815)	($10)		($15,870)	($108)	($1,081)	($1,436)	($4,027)	($998)	($41)	($121)	($258)
46	AMORT. OF INV. TAX CREDIT	($12,202)	($11,583)	($619)		($5,441)	($37)	($334)	($542)	($1,697)	($454)	($20)	($50)	($101)
47	SUBTOTAL EXPENSES	$6,864,371	$6,481,871	$839,734		$2,512,128	$17,858	$165,122	$270,114	$914,746	$267,064	$11,344	$28,979	$49,451
48	TOTAL INCOME TAXES	$263,510	$230,637	$3,852		$54,225	$456	$6,152	$26,362	$77,387	$15,841	$98	$2,680	$5,182
49	TOTAL EXPENSES	$7,127,881	$6,712,508	$643,566		$2,566,353	$18,314	$171,274	$296,476	$992,134	$282,905	$11,442	$29,659	$54,632
	— RETURN —													
50	OPERATING INCOME	$867,564	$799,130	($159,779)		$290,151	$2,128	$22,665	$62,283	$186,383	$42,115	$905	$6,162	$12,017
51	INT. ON CUSTOMER DEPOSITS	($4,271)	($4,271)	$0	Cust Deposits	($1,678)	($12)	($115)	($215)	($710)	($196)	$0	$0	($40)
52	NET INCOME	$863,293	$794,859	($159,779)		$288,473	$2,116	$22,551	$62,067	$185,673	$41,919	$905	$6,162	$11,977
53	RETURN ON INVESTMENT	5.77%				4.25%	4.52%	5.25%	9.10%	8.76%	7.41%	3.63%	9.67%	9.47%

Georgia Power Company
Staff Cost of Service Study
Peak Average Method
Summary

LINE NO.	LINE DESCRIPTION	ELECTRIC SYSTEM	RETAIL SERVICE	ALL OTHER SERVICE	ALLOC	RATE TOU-GSD	RATE TOU-SSD	RATE TOU-MAM	RATE TOU-MLM	RATE TOU - SC	RATE TOU-HLF	RATE TOU-HLF	RATE RTP-DA	RATE RTP-HA	RATE SLM
	— RATE BASE —														
1	GROSS PLANT	$26,404,947	$25,406,065	$998,882		$110,193	$9,338	$2,602	$113,601	$97,185	$29,101	$162,011	$2,230,644	$1,249,576	$588,745
2	ACCUMULATED DEPRECIATION	$10,206,026	$9,725,882	$480,344		$42,078	$3,675	$999	$44,246	$38,328	$11,259	$62,112	$859,821	$493,153	$225,235
3	NUCLEAR FUEL	$524,588	$524,334	$254		$2,547	$257	$61	$3,227	$2,984	$731	$3,785	$54,858	$37,496	$13,767
4	ACCUM. DEPR. OF NUCLEAR FUEL	$208,518	$208,417	$101		$1,012	$102	$24	$1,283	$1,186	$290	$1,504	$21,726	$14,904	$5,472
5	NET ELECTRIC PLANT	$16,514,991	$15,996,300	$518,691		$69,649	$5,815	$1,640	$71,299	$60,634	$18,282	$102,180	$1,403,755	$779,016	$371,804
	LESS: DEFERRED INCOME TAXES														
6	ACCOUNT 190	($467,358)	($456,722)	($10,636)		($1,718)	($123)	($35)	($1,434)	($1,155)	($388)	($2,353)	($31,063)	($15,242)	($8,055)
7	ACCOUNT 281 AND 282	$2,984,939	$2,903,529	$81,410		$12,551	$1,044	$296	$12,753	$10,813	$3,288	$18,367	$252,615	$139,165	$66,973
8	ACCOUNT 283	$378,674	$368,057	$10,617		$1,445	$116	$30	$1,382	$1,178	$344	$2,021	$29,176	$16,744	$6,911
9	TOTAL DEFERRED INCOME TAX	$2,896,255	$2,814,864	$81,391		$12,277	$1,037	$291	$12,701	$10,835	$3,248	$18,055	$250,729	$140,667	$65,829
	ADD: OTHER RATE BASE ITEMS														
10	PLANT HELD FOR FUTURE USE	$93,921	$93,869	$52		$485	$33	$11	$453	$439	$117	$639	$8,487	$4,826	$2,533
11	MATERIALS AND SUPPLIES	$921,677	$855,820	$65,857		$4,047	$398	$97	$4,954	$4,542	$1,142	$5,998	$85,839	$57,287	$21,717
12	PAYABLES ASSOC. W/ CAP M&S	($1,077)	($1,077)	$0	Plt M&S	($5)	$0	$0	($6)	($5)	($1)	($7)	($102)	($65)	($26)
13	MIN BANK BAL, PC, PREPAIDS	$87,094	$85,726	$1,368		$373	$31	$9	$382	$325	$98	$548	$7,523	$4,175	$1,993
14	PREPAID PENSION ASSET	$516,201	$492,106	$24,095		$1,777	$133	$34	$1,546	$1,277	$388	$2,423	$36,661	$20,610	$7,894
15	CUSTOMER DEPOSITS	($257,322)	($257,322)	$0	Special	($1,383)	($137)	($28)	($1,447)	($1,084)	($312)	($1,694)	($34,882)	($24,906)	$0
16	OPERATING RESERVES	($202,972)	($196,392)	($6,580)		($705)	($45)	($13)	($522)	($405)	($142)	($913)	($11,764)	($5,357)	($3,010)
17	DEFERRED MCINTOSH C INSPECTION	$7,200	$7,197	$3	2	$35	$4	$1	$44	$41	$10	$52	$750	$515	$189
18	DEFERRED NUCLEAR OUT. COSTS	$15,634	$15,626	$8	2	$76	$8	$2	$96	$89	$22	$113	$1,629	$1,117	$410
19	ECCR DEFERRED REG ASSET	$11,581	$11,575	$6	2	$56	$6	$1	$71	$66	$16	$84	$1,207	$828	$304
20	ARO REGULATORY ASSET	$796,862	$796,487	$395	ARO asset	$3,911	$399	$95	$5,022	$4,662	$1,129	$5,820	$84,343	$58,511	$21,198
21	ARO LIABILITY	($775,594)	($775,211)	($383)	ARO asset	($3,806)	($388)	($92)	($4,888)	($4,537)	($1,099)	($5,685)	($82,092)	($56,949)	($20,632)
22	ARO REGULATORY LIABILITY	($119,346)	($119,288)	($58)	2	($579)	($58)	($14)	($734)	($879)	($166)	($861)	($12,435)	($8,531)	($3,132)
23	REGULATORY ASSET - DEF INC TX	$57,935	$57,914	$21	Headcount	$220	$16	$4	$188	$155	$49	$295	$3,908	$2,020	$995
24	GREEN ENERGY OVER/UNDER REC	$0	$0	$0	36	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	M&S INVENTORY ADJUSTMENT - STEAM	$4,860	$4,858	$2	M&S Prod Plt	$24	$2	$1	$30	$28	$7	$35	$506	$347	$128
26	REG LIAB - NON ARO COST OF REMOVAL	($86,942)	($88,914)	($28)		($331)	($26)	($8)	($275)	($219)	($85)	($506)	($6,583)	($2,984)	($1,780)
27	HAMMOND COOLING TOWER RENTAL	$12,681	$12,675	$6	2	$62	$6	$1	$78	$72	$18	$91	$1,321	$906	$333
28	CASH WORKING CAPITAL	$262,258	$246,387	$15,871		$1,153	$118	$25	$1,376	$1,063	$293	$1,491	$32,665	$25,506	$5,035
29	TOTAL OTHER RATE BASE ITEMS	$1,344,651	$1,244,016	$100,635		$5,367	$498	$128	$6,368	$5,849	$1,482	$7,943	$117,181	$77,858	$34,147
30	TOTAL INVESTMENT	$14,963,387	$14,425,452	$537,935		$62,759	$5,276	$1,475	$64,967	$55,648	$16,519	$92,068	$1,270,208	$716,206	$340,123
	— REVENUES —														
31	REVENUE FROM SALES	$7,739,600	$7,281,383	$458,217		$37,211	$3,705	$781	$39,062	$28,809	$8,416	$45,686	$937,847	$683,456	$142,035
32	OTHER OPERATING REVENUES	$255,845	$230,255	$25,590		$772	$53	$17	$748	$591	$187	$1,103	$14,686	$7,529	$4,042
33	TOTAL REVENUES	$7,995,445	$7,511,638	$483,807		$37,983	$3,758	$779	$39,810	$29,400	$8,603	$46,789	$952,534	$690,985	$146,077
	— EXPENSES —														
34	OPERATIONS & MAINTENANCE	$5,942,402	$5,604,435	$594,403		$24,106	$2,487	$557	$31,895	$25,757	$6,847	$33,300	$747,829	$598,308	$121,810
35	DEPRECIATION EXPENSE	$778,573	$737,917	$40,656		$3,097	$260	$73	$3,091	$2,614	$813	$4,595	$62,493	$33,964	$16,522
36	ARO DEPRECIATION EXPENSE	($21)	($21)	$0		$0	$0	$0	$0	$0	$0	$0	($4)	($3)	($1)
37	ARO ACCRETION	$48,899	$48,876	$23		$237	$24	$6	$299	$278	$68	$352	$5,074	$3,471	$1,279
38	ARO DEFERRAL	($48,878)	($46,855)	($23)		($237)	($24)	($8)	($299)	($278)	($68)	($351)	($5,070)	($3,467)	($1,278)
39	NUCLEAR DECOM EXPENSE	$1,686	$1,685	$1	2	$8	$1	$0	$10	$10	$2	$12	$176	$121	$44
40	TAXES OTHER THAN INC. TAX	$186,491	$181,996	$5,293		$697	$59	$16	$719	$619	$181	$1,011	$13,928	$7,950	$3,635
41	AMORT. OF DEF HEALTHCARE COSTS	$4,165	$4,163	$2		$16	$1	$0	$14	$11	$3	$21	$281	$145	$72
42	AMORT. OF HAMMOND COOLING TOWER	$5,415	$5,412	$3	2	$26	$3	$1	$33	$31	$8	$39	$564	$387	$142
43	AMORT. DEFERRAL OF ECCR	$7,586	$7,582	$4	2	$37	$4	$1	$47	$43	$11	$55	$790	$542	$199
44	AMORT. OF M&S INVENTORY ADJ.	$1,080	$1,079	$1		$5	$1	$0	$7	$6	$2	$8	$113	$77	$28
45	AMORT. OF COST OF REMOVAL ADJ.	($30,825)	($30,815)	($10)		($118)	($9)	($3)	($97)	($78)	($30)	($179)	($2,334)	($1,058)	($631)
46	AMORT. OF INV. TAX CREDIT	($12,202)	($11,583)	($619)		($50)	($4)	($1)	($52)	($44)	($13)	($74)	($1,017)	($570)	($268)
47	SUBTOTAL EXPENSES	$6,864,371	$6,481,871	$639,734		$27,824	$2,801	$644	$35,686	$28,970	$7,923	$38,787	$822,823	$639,866	$141,553
48	TOTAL INCOME TAXES	$263,510	$230,637	$3,852		$3,200	$309	$35	$849	($480)	$110	$2,025	$35,427	$11,472	($2,203)
49	TOTAL EXPENSES	$7,127,881	$6,712,508	$643,586		$31,025	$3,110	$879	$36,514	$28,490	$7,933	$40,812	$858,251	$651,339	$139,351
	— RETURN —														
50	OPERATING INCOME	$867,564	$799,130	($159,779)		$6,958	$648	$100	$3,296	$910	$670	$5,977	$94,283	$39,646	$6,727
51	INT. ON CUSTOMER DEPOSITS	($4,271)	($4,271)	$0	Cust Deposits	($23)	($2)	$0	($24)	($18)	($5)	($28)	($579)	($413)	$0
52	NET INCOME	$863,293	$794,859	($159,779)		$6,935	$646	$99	$3,272	$892	$665	$5,948	$93,704	$39,233	$6,727
53	RETURN ON INVESTMENT	5.77%				11.05%	12.23%	6.73%	5.04%	1.60%	4.03%	6.48%	7.38%	5.48%	1.98%

Georgia Power Company
Staff Cost of Service Study
Peak Average Method
Summary

LINE NO.	LINE DESCRIPTION	ELECTRIC SYSTEM	RETAIL SERVICE	ALL OTHER SERVICE	ALLOC	RATE OLG	RATE OLNG	RATE EOL	RATE UC	RATE FPA	RATE TC	RATE APS, TOU-FS, IOP	RATE SAS	RATE OGS
	— RATE BASE —													
1	GROSS PLANT	$26,404,947	$25,406,085	$998,862		$314,778	$182,171	$84,464	$27,468	$1,075,043	$16,221	$72,604	$9,823	$3,762
2	ACCUMULATED DEPRECIATION	$10,206,028	$9,725,682	$480,344		$160,458	$90,383	$33,859	$10,641	$418,601	$6,284	$27,294	$3,700	$1,420
3	NUCLEAR FUEL	$524,588	$524,334	$254		$1,906	$1,167	$1,725	$514	$29,898	$376	$956	$153	$41
4	ACCUM. DEPR. OF NUCLEAR FUEL	$208,518	$208,417	$101		$757	$472	$686	$204	$11,884	$149	$380	$61	$16
5	NET ELECTRIC PLANT	$18,514,991	$15,996,300	$518,691		$155,468	$92,503	$51,644	$17,135	$674,456	$10,164	$45,886	$6,215	$2,367
	LESS: DEFERRED INCOME TAXES													
6	ACCOUNT 190	($467,358)	($456,722)	($10,636)		($6,031)	($4,802)	($2,280)	($1,088)	($13,905)	($337)	($1,428)	($236)	($167)
7	ACCOUNT 281 AND 282	$2,984,939	$2,903,529	$61,410		$36,671	$21,199	$9,458	$3,134	$120,809	$1,839	$8,402	$1,132	$436
8	ACCOUNT 283	$378,674	$368,057	$10,617		$4,586	$3,446	$1,789	$825	$13,113	$274	$1,018	$178	$121
9	TOTAL DEFERRED INCOME TAX	$2,896,255	$2,814,864	$81,391		$35,226	$20,043	$8,967	$2,871	$120,017	$1,776	$7,993	$1,073	$391
	ADD: OTHER RATE BASE ITEMS													
10	PLANT HELD FOR FUTURE USE	$93,921	$93,869	$52		$21	$13	$18	$69	$4,352	$58	$172	$27	$6
11	MATERIALS AND SUPPLIES	$921,677	$855,620	$65,857		$4,567	$2,682	$2,960	$925	$46,068	$608	$1,736	$272	$90
12	PAYABLES ASSOC. W/ CAP M&S	($1,077)	($1,077)	$0	Plt M&S	($8)	($5)	($4)	($1)	($53)	($1)	($3)	$0	$0
13	MIN BANK BAL, PC, PREPAIDS	$87,094	$85,726	$1,368		$833	$496	$277	$92	$3,614	$54	$246	$33	$13
14	PREPAID PENSION ASSET	$518,201	$492,106	$24,095		$7,341	$5,752	$2,767	$1,377	$14,729	$383	$1,419	$267	$209
15	CUSTOMER DEPOSITS	($257,322)	($257,322)	$0	Special	$0	$0	$0	($444)	($11,733)	$0	($429)	($69)	($45)
16	OPERATING RESERVES	($202,972)	($196,392)	($6,580)		($2,441)	($2,147)	($1,137)	($597)	($5,140)	($157)	($625)	($115)	($95)
17	DEFERRED MCINTOSH C INSPECTION	$7,200	$7,197	$3	2	$28	$16	$24	$7	$410	$5	$13	$2	$1
18	DEFERRED NUCLEAR OUT. COSTS	$15,634	$15,626	$8	2	$57	$35	$51	$15	$891	$11	$28	$5	$1
19	ECCR DEFERRED REG ASSET	$11,581	$11,575	$6	2	$42	$26	$38	$11	$660	$8	$21	$3	$1
20	ARO REGULATORY ASSET	$796,862	$796,467	$395	ARO asset	$2,372	$1,464	$2,581	$749	$46,475	$573	$1,387	$225	$55
21	ARO LIABILITY	($775,594)	($775,211)	($383)	ARO asset	($2,308)	($1,425)	($2,513)	($729)	($45,235)	($558)	($1,350)	($219)	($53)
22	ARO REGULATORY LIABILITY	($119,346)	($119,288)	($58)	2	($434)	($270)	($393)	($117)	($6,802)	($86)	($217)	($35)	($9)
23	REGULATORY ASSET - DEF INC TX	$57,935	$57,914	$21	Headcount	$651	$556	$314	$155	$1,817	$45	$172	$31	$24
24	GREEN ENERGY OVER/UNDER REC	$0	$0	$0	38	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	M&S INVENTORY ADJUSTMENT - STEAM	$4,860	$4,858	$2	M&S Prod Plt	$18	$11	$16	$5	$277	$3	$9	$1	$0
26	REG LIAB - NON ARO COST OF REMOVAL	($86,942)	($86,914)	($28)		($1,910)	($1,080)	($362)	($101)	($2,697)	($51)	($337)	($41)	($18)
27	HAMMOND COOLING TOWER RENTAL	$12,681	$12,675	$6	2	$46	$29	$42	$12	$723	$9	$23	$4	$1
28	CASH WORKING CAPITAL	$282,258	$246,387	$15,871		$1,911	$1,331	$1,195	$376	$11,457	$136	$415	$71	$38
29	TOTAL OTHER RATE BASE ITEMS	$1,344,651	$1,244,016	$100,635		$10,783	$7,884	$5,874	$1,805	$59,812	$1,042	$2,682	$462	$218
30	TOTAL INVESTMENT	$14,963,387	$14,425,452	$537,935		$131,025	$80,145	$48,551	$16,069	$614,251	$9,430	$40,575	$5,604	$2,194
	— REVENUES —													
31	REVENUE FROM SALES	$7,739,600	$7,281,383	$458,217		$88,441	$46,021	$34,895	$11,905	$317,252	$2,920	$11,553	$1,872	$1,218
32	OTHER OPERATING REVENUES	$255,845	$230,255	$25,590		$1,413	$908	$375	$463	$7,016	$112	$471	$65	$26
33	TOTAL REVENUES	$7,995,445	$7,511,638	$483,807		$89,854	$46,929	$35,269	$12,368	$324,268	$3,032	$12,024	$1,937	$1,244
	— EXPENSES —													
34	OPERATIONS & MAINTENANCE	$5,942,402	$5,604,435	$594,403		$40,890	$28,080	$26,755	$7,528	$273,905	$3,873	$10,778	$1,825	$794
35	DEPRECIATION EXPENSE	$778,573	$737,917	$40,656		$14,301	$7,996	$2,583	$611	$29,381	$461	$2,240	$298	$119
36	ARO DEPRECIATION EXPENSE	($21)	($21)	$0		$1	$0	$0	$0	($2)	$0	$0	$0	$0
37	ARO ACCRETION	$48,899	$48,876	$23		$188	$116	$161	$46	$2,770	$35	$90	$14	$4
38	ARO DEFERRAL	($48,878)	($48,855)	($23)		($187)	($116)	($161)	($48)	($2,768)	($35)	($90)	($14)	($4)
39	NUCLEAR DECOM EXPENSE	$1,686	$1,685	$1	2	$6	$4	$6	$2	$96	$1	$3	$0	$0
40	TAXES OTHER THAN INC. TAX	$166,491	$161,996	$5,293		$1,811	$1,142	$597	$220	$6,798	$109	$447	$65	$30
41	AMORT. OF DEF HEALTHCARE COSTS	$4,165	$4,163	$2		$47	$40	$23	$11	$131	$3	$12	$2	$2
42	AMORT. OF HAMMOND COOLING TOWER	$5,415	$5,412	$3	2	$20	$12	$16	$5	$309	$4	$10	$2	$0
43	AMORT. DEFERRAL OF ECCR	$7,586	$7,582	$4	2	$28	$17	$25	$7	$432	$5	$14	$2	$1
44	AMORT. OF M&S INVENTORY ADJ.	$1,080	$1,079	$1		$4	$2	$4	$1	$62	$1	$2	$0	$0
45	AMORT. OF COST OF REMOVAL ADJ.	($30,825)	($30,815)	($10)		($677)	($383)	($128)	($38)	($958)	($18)	($119)	($15)	($6)
46	AMORT. OF INV. TAX CREDIT	($12,202)	($11,583)	($619)		($144)	($83)	($39)	($13)	($490)	($7)	($33)	($4)	($2)
47	SUBTOTAL EXPENSES	$6,864,371	$6,481,871	$639,734		$56,265	$36,827	$29,643	$8,537	$309,666	$4,431	$13,353	$2,176	$939
48	TOTAL INCOME TAXES	$263,510	$230,637	$3,852		$3,710	$2,969	$1,536	$1,296	($1,489)	($651)	($986)	($158)	$93
49	TOTAL EXPENSES	$7,127,881	$6,712,508	$643,586		$59,995	$39,796	$31,379	$9,833	$308,177	$3,780	$12,368	$2,019	$1,032
	— RETURN —													
50	OPERATING INCOME	$867,564	$799,130	($159,779)		$9,859	$7,133	$3,890	$2,536	$16,091	($748)	($344)	($81)	$212
51	INT. ON CUSTOMER DEPOSITS	($4,271)	($4,271)	$0	Cust Deposits	$0	$0	$0	($7)	($195)	$0	($7)	($1)	($1)
52	NET INCOME	$863,293	$794,859	($159,779)		$9,859	$7,133	$3,890	$2,528	$15,896	($748)	($351)	($82)	$212
53	RETURN ON INVESTMENT	5.77%				7.52%	8.90%	8.01%	15.73%	2.59%	-7.94%	-0.88%	-1.47%	9.64%

Georgia Power Company
Staff Cost of Service Study
Peak Average Method
Summary

LINE NO.	LINE DESCRIPTION	ELECTRIC SYSTEM	RETAIL SERVICE	ALL OTHER SERVICE	ALLOC	DOMESTIC	SMALL BUSINESS	MEDIUM BUSINESS	LARGE BUSINESS	AGRICULTURAL	GOVERNMENT/ INSTITUTION	LIGHTING	MARGINAL
	— RATE BASE —												
1	GROSS PLANT	$26,404,947	$25,406,065	$998,882		$12,033,005	$2,169,509	$4,000,236	$1,146,986	$68,028	$758,653	$580,384	$4,649,393
2	ACCUMULATED DEPRECIATION	$10,206,026	$9,725,682	$480,344		$4,534,513	$810,494	$1,528,392	$443,247	$25,674	$290,322	$264,320	$1,808,778
3	NUCLEAR FUEL	$524,588	$524,334	$254		$214,209	$39,187	$92,803	$29,414	$1,109	$17,763	$4,818	$125,035
4	ACCUM. DEPR. OF NUCLEAR FUEL	$208,518	$208,417	$101		$85,146	$15,577	$36,886	$11,692	$441	$7,061	$1,915	$49,700
5	NET ELECTRIC PLANT	$16,514,991	$15,996,300	$518,891		$7,627,555	$1,382,626	$2,527,759	$721,461	$43,022	$479,033	$298,967	$2,915,951
	LESS: DEFERRED INCOME TAXES												
6	ACCOUNT 190	($467,358)	($456,722)	($10,636)		($242,569)	($52,732)	($59,990)	($15,276)	($1,382)	($10,578)	($12,892)	($81,123)
7	ACCOUNT 281 AND 282	$2,984,939	$2,903,529	$81,410		$1,385,016	$249,622	$455,006	$129,589	$7,829	$86,277	$67,206	$523,043
8	ACCOUNT 283	$378,674	$368,057	$10,617		$181,989	$41,183	$51,050	$13,762	$1,041	$9,068	$9,809	$56,695
9	TOTAL DEFERRED INCOME TAX	$2,896,255	$2,814,804	$81,391		$1,324,436	$238,053	$446,066	$128,074	$7,488	$84,768	$64,123	$518,616
	ADD: OTHER RATE BASE ITEMS												
10	PLANT HELD FOR FUTURE USE	$93,921	$93,869	$52		$42,875	$7,905	$16,776	$4,743	$199	$3,215	$52	$18,105
11	MATERIALS AND SUPPLIES	$921,677	$855,820	$65,857		$361,678	$67,029	$147,216	$45,827	$1,918	$28,042	$10,402	$193,716
12	PAYABLES ASSOC. W/ CAP M&S	($1,077)	($1,077)	$0	Plt M&S	($477)	($90)	($177)	($54)	($3)	($34)	($18)	($225)
13	MIN BANK BAL, PC, PREPAIDS	$87,094	$85,726	$1,368		$40,877	$7,410	$13,547	$3,866	$231	$2,567	$1,602	$15,627
14	PREPAID PENSION ASSET	$518,201	$492,106	$24,095		$251,334	$62,158	$61,950	$15,820	$1,470	$10,499	$15,844	$64,467
15	CUSTOMER DEPOSITS	($257,322)	($257,322)	$0	Special	($101,838)	($22,786)	($45,906)	($13,709)	($498)	$0	$0	($72,585)
16	OPERATING RESERVES	($202,972)	($196,392)	($6,580)		($108,039)	($25,787)	($23,900)	($5,676)	($625)	($4,006)	($5,717)	($22,641)
17	DEFERRED MCINTOSH C INSPECTION	$7,200	$7,197	$3	2	$2,940	$538	$1,274	$404	$15	$244	$66	$1,716
18	DEFERRED NUCLEAR OUT. COSTS	$15,634	$15,826	$8	2	$6,384	$1,168	$2,786	$877	$33	$529	$144	$3,728
19	ECCR DEFERRED REG ASSET	$11,581	$11,575	$6	2	$4,729	$865	$2,049	$649	$24	$392	$106	$2,760
20	ARO REGULATORY ASSET	$796,862	$796,467	$395	ARO asset	$320,589	$58,342	$142,603	$45,528	$1,646	$27,344	$6,420	$193,998
21	ARO LIABILITY	($775,594)	($775,211)	($383)	ARO asset	($312,033)	($56,785)	($138,797)	($44,313)	($1,602)	($26,614)	($6,248)	($188,820)
22	ARO REGULATORY LIABILITY	($119,346)	($119,288)	($58)	2	($48,733)	($8,915)	($21,113)	($6,692)	($252)	($4,041)	($1,096)	($28,446)
23	REGULATORY ASSET - DEF INC TX	$57,935	$57,914	$21	Headcount	$30,459	$7,031	$7,587	$1,941	$175	$1,313	$1,519	$7,894
24	GREEN ENERGY OVER/UNDER REC	$0	$0	$0	36	$0	$0	$0	$0	$0	$0	$0	$0
25	M&S INVENTORY ADJUSTMENT - STEAM	$4,960	$4,858	$2	M&S Prod Plt	$1,985	$363	$880	$273	$10	$165	$45	$1,158
26	REG LIAB - NON ARO COST OF REMOVAL	($86,942)	($86,914)	($28)		($45,164)	($7,928)	($12,221)	($3,198)	($281)	($2,295)	($3,345)	($12,483)
27	HAMMOND COOLING TOWER RENTAL	$12,681	$12,675	$6	2	$5,178	$947	$2,243	$711	$27	$429	$116	$3,023
28	CASH WORKING CAPITAL	$262,258	$246,387	$15,871		$91,951	$19,392	$39,247	$12,302	$479	$6,687	$4,436	$71,220
29	TOTAL OTHER RATE BASE ITEMS	$1,344,651	$1,244,016	$100,635		$544,678	$110,858	$196,002	$59,099	$2,967	$44,436	$24,328	$252,231
30	TOTAL INVESTMENT	$14,963,387	$14,425,452	$537,935		$8,847,794	$1,255,430	$2,277,694	$652,486	$38,500	$438,701	$259,172	$2,849,566
	— REVENUES —												
31	REVENUE FROM SALES	$7,739,600	$7,281,383	$458,217		$2,741,274	$612,229	$1,236,064	$369,625	$13,427	$192,046	$149,357	$1,967,368
32	OTHER OPERATING REVENUES	$255,845	$230,255	$25,590		$135,755	$20,721	$28,016	$7,566	$467	$5,234	$2,691	$29,808
33	TOTAL REVENUES	$7,995,445	$7,511,638	$483,807		$2,877,029	$632,949	$1,264,079	$377,191	$13,894	$197,280	$152,048	$1,997,175
	— EXPENSES —												
34	OPERATIONS & MAINTENANCE	$5,942,402	$5,604,435	$594,403		$2,114,795	$417,139	$847,121	$274,977	$11,936	$158,917	$95,678	$1,658,053
35	DEPRECIATION EXPENSE	$778,573	$737,917	$40,656		$352,438	$64,250	$112,875	$31,806	$2,048	$21,308	$24,845	$128,349
36	ARO DEPRECIATION EXPENSE	($21)	($21)	$0		($3)	$0	($6)	($2)	$0	($1)	$1	($10)
37	ARO ACCRETION	$48,899	$48,876	$23		$20,043	$3,671	$8,625	$2,728	$104	$1,850	$463	$11,591
38	ARO DEFERRAL	($48,878)	($48,855)	($23)		($20,040)	($3,671)	($8,619)	($2,726)	($104)	($1,649)	($464)	($11,581)
39	NUCLEAR DECOM EXPENSE	$1,686	$1,685	$1	2	$888	$126	$298	$95	$4	$57	$15	$402
40	TAXES OTHER THAN INC. TAX	$168,491	$161,996	$5,293		$77,080	$14,697	$25,095	$7,172	$433	$4,702	$3,544	$29,278
41	AMORT. OF DEF HEALTHCARE COSTS	$4,165	$4,163	$2		$2,190	$505	$545	$140	$13	$94	$109	$567
42	AMORT. OF HAMMOND COOLING TOWER	$5,415	$5,412	$3	2	$2,211	$405	$958	$304	$11	$183	$50	$1,291
43	AMORT. DEFERRAL OF ECCR	$7,586	$7,582	$4	2	$3,098	$567	$1,342	$425	$16	$257	$70	$1,806
44	AMORT. OF M&S INVENTORY ADJ.	$1,080	$1,079	$1		$441	$81	$191	$61	$2	$37	$10	$257
45	AMORT. OF COST OF REMOVAL ADJ.	($30,825)	($30,815)	($10)		($16,020)	($2,811)	($4,333)	($1,134)	($99)	($814)	($1,186)	($4,419)
46	AMORT. OF INV. TAX CREDIT	($12,202)	($11,583)	($619)		($5,486)	($989)	($1,824)	($523)	($31)	($346)	($265)	($2,120)
47	SUBTOTAL EXPENSES	$6,864,371	$6,481,871	$639,734		$2,531,435	$493,968	$982,269	$313,321	$14,333	$184,395	$122,870	$1,813,466
48	TOTAL INCOME TAXES	$263,510	$230,637	$3,852		$54,044	$39,168	$82,530	$17,122	($617)	($114)	$8,251	$40,308
49	TOTAL EXPENSES	$7,127,881	$6,712,508	$643,586		$2,585,479	$533,137	$1,064,800	$330,444	$13,716	$184,281	$131,121	$1,853,774
	— RETURN —												
50	OPERATING INCOME	$867,564	$799,130	($159,779)		$291,550	$99,812	$199,280	$48,747	$178	$12,999	$20,926	$143,401
51	INT. ON CUSTOMER DEPOSITS	($4,271)	($4,271)	$0	Cust Deposits	($1,690)	($378)	($782)	($228)	($8)	$0	$0	($1,205)
52	NET INCOME	$863,293	$794,859	($159,779)		$289,860	$99,434	$198,518	$48,520	$170	$12,999	$20,926	$142,197
53	RETURN ON INVESTMENT	5.77%				4.23%	7.92%	8.72%	7.13%	0.44%	2.96%	8.07%	5.37%

Georgia Power
Comparison of Cost of Service Study Results

	Indexed Rate of Return @ Current Rates			
	Per Company		Per Staff	
Class	12CP	4CP	Peak & Average	BIP
Domestic Group				
R, RM	65%	60%	74%	76%
TOU-REO	72%	67%	78%	80%
Total Domestic Group	**65%**	**60%**	**73%**	**75%**
Small Business Group				
GS	90%	73%	91%	94%
PLS	158%	139%	158%	160%
OGS	172%	193%	167%	165%
UC	307%	332%	273%	266%
TOU-EO	157%	140%	164%	168%
Total Small Business Group	**137%**	**119%**	**137%**	**140%**
Medium Business Group				
PLM	160%	148%	152%	152%
TOU-MB	133%	120%	112%	111%
TOU-MAM	116%	126%	117%	116%
TOU-GSD	187%	188%	192%	192%
Total Medium Business Group	**159%**	**148%**	**151%**	**151%**
Large Business Group				
PLL	140%	146%	128%	126%
TOU-SSD	238%	320%	212%	201%
TOU-MLM	112%	138%	87%	81%
TOU-HLF	88%	88%	70%	67%
Total Large Business Group	**137%**	**145%**	**124%**	**121%**
Agricultural Group				
SAS	-21%	-24%	-25%	-25%
APS,TOU-FS,IOP	-1%	-17%	-15%	-15%
Total Agricultural Group	**26%**	**6%**	**8%**	**8%**
Government/Institutional Group				
SCH	168%	173%	168%	167%
SLM	31%	31%	34%	35%
TC	-138%	-134%	-138%	-138%
G	86%	26%	63%	62%
Total Government/Institutional Group	**50%**	**50%**	**51%**	**51%**
Outdoor Lighting Group				
EOL	196%	461%	139%	118%
OLG	150%	212%	130%	122%
OLNG	177%	244%	154%	145%
Total Outdoor Lighting Group	**167%**	**255%**	**140%**	**129%**
Marginally Priced Group				
RTP-DA	118%	131%	128%	124%
RTP-HA	101%	151%	95%	87%
FPA	53%	82%	45%	41%
TOU-SC	52%	62%	28%	24%
Total Marginally Priced Group	**97%**	**124%**	**93%**	**88%**
Total	**100%**	**100%**	**100%**	**100%**

Georgia Power
Comparison of Cost of Service Study Results

	Rate or Return at Current Rates			
	Per Company		Per Staff	
Class	12CP	4CP	Peak & Average	BIP
Domestic Group				
R, RM	3.74%	3.49%	4.25%	4.36%
TOU-REO	4.15%	3.86%	4.52%	4.62%
Total Domestic Group	**3.73%**	**3.48%**	**4.23%**	**4.34%**
Small Business Group				
GS	5.21%	4.19%	5.25%	5.40%
PLS	9.12%	8.02%	9.10%	9.26%
OGS	9.93%	11.12%	9.64%	9.50%
UC	17.69%	19.15%	15.73%	15.33%
TOU-EO	9.07%	8.08%	9.47%	9.67%
Total Small Business Group	**7.90%**	**6.84%**	**7.92%**	**8.08%**
Medium Business Group				
PLM	9.22%	8.55%	8.76%	8.78%
TOU-MB	7.70%	6.93%	6.46%	6.39%
TOU-MAM	6.69%	7.26%	6.73%	6.67%
TOU-GSD	10.79%	10.82%	11.05%	11.09%
Total Medium Business Group	**9.19%**	**8.54%**	**8.72%**	**8.74%**
Large Business Group				
PLL	8.08%	8.42%	7.41%	7.28%
TOU-SSO	13.76%	18.45%	12.23%	11.58%
TOU-MLM	6.48%	7.98%	5.04%	4.70%
TOU-HLF	5.07%	5.09%	4.03%	3.89%
Total Large Business Group	**7.90%**	**8.37%**	**7.13%**	**6.97%**
Agricultural Group				
SAS	-1.19%	-1.38%	-1.47%	-1.47%
APS,TOU-FS,IOP	-0.03%	-0.96%	-0.86%	-0.85%
Total Agricultural Group	**1.48%**	**0.32%**	**0.44%**	**0.46%**
Government/Institutional Group				
SCH	9.70%	9.96%	9.67%	9.64%
SLM	1.77%	1.79%	1.98%	2.01%
TC	-7.96%	-7.71%	-7.94%	-7.98%
G	4.94%	1.48%	3.63%	3.55%
Total Government/Institutional Group	**2.86%**	**2.89%**	**2.96%**	**2.97%**
Outdoor Lighting Group				
EOL	11.31%	26.61%	8.01%	6.81%
OLG	8.64%	12.23%	7.52%	7.02%
OLNG	10.20%	14.08%	8.90%	8.35%
Total Outdoor Lighting Group	**9.62%**	**14.74%**	**8.07%**	**7.42%**
Marginally Priced Group				
RTP-DA	6.81%	7.58%	7.38%	7.17%
RTP-HA	5.81%	8.73%	5.48%	5.01%
FPA	3.07%	4.72%	2.59%	2.34%
TOU-SC	2.99%	3.57%	1.60%	1.37%
Total Marginally Priced Group	**5.60%**	**7.13%**	**5.37%**	**5.08%**
Total	**5.77%**	**5.77%**	**5.77%**	**5.77%**

Georgia Power Company
Company Proposed Revenue Distribution

Customer Class	Company Proposed Percent Increase							
	Base Revenue	ILR	ECCR	DSM	MFF	Fuel Revenue	Total Rev Less Fuel	Total Rev
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Domestic Group								
R, RM	16.44%	--	85.94%	1068.26%	16.07%	0.00%	21.79%	13.23%
TOU-REO	16.42%	--	85.92%	1079.53%	16.09%	0.00%	21.78%	13.25%
Total Domestic Group	**16.44%**	--	**85.94%**	**1068.34%**	**16.07%**	**0.00%**	**21.79%**	**13.23%**
Small Business Group								
GS	16.42%	--	85.92%	--	18.11%	0.00%	20.75%	15.22%
PLS	16.42%	0.00%	85.92%	--	16.10%	0.00%	20.66%	13.26%
DGS	16.42%	--	85.92%	--	19.10%	0.00%	20.69%	16.18%
UC	16.42%	--	85.92%	--	17.64%	0.00%	20.71%	14.76%
TOU-EO	16.42%	--	85.92%	--	16.13%	0.00%	20.64%	13.29%
Total Small Business Group	**16.42%**	--	**85.92%**	--	**16.75%**	**0.00%**	**20.69%**	**13.89%**
Medium Business Group								
PLM	16.42%	0.00%	85.92%	--	14.66%	0.00%	20.57%	11.85%
TOU-MB	16.42%	--	85.92%	--	14.21%	0.00%	20.56%	11.42%
TOU-GSD	16.42%	0.00%	85.92%	--	15.00%	0.00%	20.49%	12.19%
Total Medium Business Group	**16.42%**	**0.00%**	**85.92%**	--	**14.65%**	**0.00%**	**20.56%**	**11.85%**
Large Business Group								
PLL	16.42%	0.00%	85.93%	--	13.40%	0.00%	20.46%	10.62%
TOU-SSD	16.42%	0.00%	85.94%	--	13.98%	0.00%	20.30%	11.19%
TOU-MLM	16.42%	0.00%	86.00%	--	11.54%	0.00%	20.16%	8.61%
TOU-HLF	16.42%	--	85.92%	--	12.22%	0.00%	20.42%	9.47%
TOU-RN from FPA	42.26%	22.19%	88.28%	--	35.07%	0.00%	44.61%	19.04%
TOU-RN from MAM	16.42%	--	85.92%	--	13.70%	0.00%	20.53%	10.92%
Total Large Business Group	**22.04%**	**17.13%**	**86.01%**		**18.63%**	**0.00%**	**25.68%**	**12.56%**
Agricultural Group								
SAS	16.42%	--	85.92%	--	13.16%	0.00%	20.43%	10.39%
APS,TOU-FS,IOP	16.42%	--	85.92%	--	13.67%	0.00%	20.44%	10.69%
Total Agricultural Group	**16.42%**	--	**85.92%**	--	**13.60%**	**0.00%**	**20.44%**	**10.62%**
Government/Institutional Group								
SCH	16.42%	--	85.92%	--	14.90%	0.00%	20.60%	12.09%
SLM	16.42%	--	85.92%	--	12.12%	0.00%	20.41%	9.38%
TC	16.42%	--	85.92%	--	6.82%	0.00%	19.15%	4.20%
G	16.46%	0.00%	86.03%	--	12.15%	0.00%	20.39%	9.40%
Total Government/Institutional Group	**16.43%**	**0.00%**	**85.92%**	--	**12.55%**	**0.00%**	**20.45%**	**9.80%**
Outdoor Lighting Group								
EOL	16.38%	--	85.84%	--	13.58%	0.00%	20.55%	10.60%
OLG	16.41%	--	85.90%	--	17.99%	0.00%	20.35%	15.10%
OLNG	16.40%	--	85.87%	--	18.69%	0.00%	20.97%	15.79%
Total Outdoor Lighting Group	**16.40%**	--	**85.88%**	--	**17.16%**	**0.00%**	**20.59%**	**14.31%**
Marginally Priced Group								
RTP-DA	13.11%	0.00%	85.96%	--	9.52%	0.00%	16.37%	6.84%
CBL	16.38%	0.00%	85.96%	--	12.69%	0.00%	20.28%	10.30%
Incremental	0.00%	--	--	--	-3.17%	0.00%	-0.16%	-0.04%
RTP-HA	12.61%	0.00%	86.63%	--	7.54%	0.00%	15.67%	4.90%
CBL	16.39%	0.00%	86.63%	--	11.14%	0.00%	20.32%	7.81%
Incremental	0.00%	--	--	--	-4.51%	0.00%	-0.30%	-0.06%
FPA	0.06%	-14.06%	31.02%	--	-5.00%	0.00%	1.71%	0.73%
TOU-SC	16.42%	--	85.92%	--	10.69%	0.00%	20.24%	6.16%
Total Marginally Priced Group	**11.48%**	**-1.61%**	**78.25%**	--	**7.29%**	**0.00%**	**14.50%**	**5.50%**
Total (All Classes)	**15.89%**	**0.01%**	**84.79%**	**1319.15%**	**13.76%**	**0.00%**	**20.33%**	**10.98%**

Georgia Power Company
Company Proposed Revenue Distribution

Class	Base Revenue	ILR	ECCR	DSM	MFF	Fuel Revenue	Total Rev Less Fuel	Total Rev
		Company Proposed Dollar Increase						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Domestic Group								
R, RM	$249,877,892	$0	$80,012,260	$25,476,724	$9,133,896	$0	$364,500,772	$364,500,772
TOU-REO	$1,789,470	$0	$573,328	$182,742	$65,415	$0	$2,610,955	$2,610,955
Total Domestic Group	**$251,667,362**	**$0**	**$80,585,588**	**$25,659,466**	**$9,199,311**	**$0**	**$367,111,727**	**$367,111,727**
Small Business Group								
GS	$20,729,821	$0	$6,641,506	$527,083	$702,092	$0	$28,600,502	$28,600,502
PLS	$33,949,527	$0	$10,879,626	$834,648	$1,173,273	$0	$46,837,074	$46,837,074
OGS	$145,907	$0	$46,747	$2,837	$4,879	$0	$200,370	$200,370
UC	$1,293,369	$0	$414,376	$30,877	$43,945	$0	$1,782,567	$1,782,567
TOU-EO	$6,341,826	$0	$2,031,830	$143,565	$218,770	$0	$8,735,991	$8,735,991
Total Small Business Group	**$62,460,450**	**$0**	**$20,014,085**	**$1,539,010**	**$2,142,959**	**$0**	**$86,156,504**	**$86,156,504**
Medium Business Group								
PLM	$100,194,566	$0	$32,100,588	$2,275,805	$3,523,287	$0	$138,094,246	$138,094,246
TOU-MB	$3,816,646	$0	$1,222,803	$90,409	$135,210	$0	$5,265,068	$5,265,068
TOU-GSD	$3,346,353	$0	$1,071,912	$53,367	$116,514	$0	$4,588,166	$4,588,166
Total Medium Business Group	**$107,357,565**	**$0**	**$34,395,303**	**$2,419,601**	**$3,775,011**	**$0**	**$147,947,480**	**$147,947,480**
Large Business Group								
PLL	$24,828,854	$0	$7,951,764	$493,494	$888,869	$0	$34,162,981	$34,162,981
TOU-SSD	$307,440	$0	$98,430	$1,905	$10,788	$0	$418,563	$418,563
TOU-MLM	$2,543,381	$0	$812,995	$20,036	$93,770	$0	$3,470,182	$3,470,182
TOU-HLF	$582,182	$0	$186,524	$13,899	$21,395	$0	$804,000	$804,000
TOU-RN from FPA	$20,221,658	-$102,160	$2,504,085	$56,664	$895,802	$0	$23,576,070	$23,576,070
TOU-RN from MAM	$60,811	$0	$19,483	$1,452	$2,172	$0	$83,918	$83,918
Total Large Business Group	**$48,544,326**	**-$102,160**	**$11,573,281**	**$587,470**	**$1,912,796**	**$0**	**$62,515,714**	**$62,515,714**
Agricultural Group								
SAS	$142,770	$0	$45,741	$2,771	$5,133	$0	$196,415	$196,415
APS,TOU-FS,IOP	$924,896	$0	$296,334	$16,584	$32,912	$0	$1,270,726	$1,270,726
Total Agricultural Group	**$1,067,666**	**$0**	**$342,075**	**$19,355**	**$38,045**	**$0**	**$1,467,141**	**$1,467,141**
Government/Institutional Group								
SCH	$3,105,003	$0	$994,801	$74,127	$108,907	$0	$4,282,838	$4,282,838
SLM	$9,721,380	$0	$3,114,598	$232,081	$358,036	$0	$13,426,095	$13,426,095
TC	$89,999	$0	$28,834	$0	$4,114	$0	$122,947	$122,947
G	$831,675	$0	$265,633	$14,433	$30,443	$0	$1,142,184	$1,142,184
Total Government/Institutional Group	**$13,748,057**	**$0**	**$4,403,866**	**$320,641**	**$501,500**	**$0**	**$18,974,064**	**$18,974,064**
Outdoor Lighting Group								
EOL	$2,746,050	$0	$881,566	$80,601	$98,750	$0	$3,806,967	$3,806,967
OLG	$7,749,137	$0	$2,483,950	$0	$257,800	$0	$10,490,887	$10,490,887
OLNG	$5,287,962	$0	$1,696,106	$212,986	$180,190	$0	$7,377,244	$7,377,244
Total Outdoor Lighting Group	**$15,783,149**	**$0**	**$5,061,622**	**$293,587**	**$536,740**	**$0**	**$21,675,098**	**$21,675,098**
Marginally Priced Group								
RTP-DA	$47,304,828	$0	$15,138,565	$648,776	$1,865,101	$0	$64,957,270	$64,957,270
CBL	$47,304,829	$0	$15,138,565	$648,776	$1,989,105	$0	$85,081,275	$85,081,275
Incremental	$0	$0	$0	$0	-$124,004	$0	-$124,004	-$124,004
RTP-HA	$24,908,092	$0	$7,832,780	$98,787	$1,075,267	$0	$33,914,926	$33,914,926
CBL	$24,908,091	$0	$7,832,780	$98,787	$1,223,431	$0	$34,063,089	$34,063,089
Incremental	$0	$0	$0	$0	-$148,164	$0	-$148,164	-$148,164
FPA	$45,917	$102,160	$1,421,507	$82,950	-$201,672	$0	$1,430,861	$1,430,861
TOU-SC	$1,718,851	$0	$550,695	$33,815	$65,078	$0	$2,368,439	$2,368,439
Total Marginally Priced Group	**$73,977,686**	**$102,160**	**$24,943,547**	**$844,328**	**$2,803,774**	**$0**	**$102,671,496**	**$102,671,496**
Total	**$574,606,263**	**$0**	**$181,319,367**	**$31,683,458**	**$20,910,136**	**$0**	**$808,519,224**	**$808,519,224**

Georgia Power Company
Company Proposed Revenue Distribution

Class	Base Revenue	ILR	ECCR	DSM	Franchise Fee	Fuel Revenue	Total Base Rev	Total Rev
	Company Proposed Revenue 1/							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Domestic Group								
R, RM	$1,770,049,515	$0	$173,116,691	$27,861,612	$65,962,872	$1,082,386,623	$2,036,990,690	$3,119,377,313
TOU-REO	$12,685,020	$0	$1,240,637	$199,670	$472,038	$7,725,282	$14,597,365	$22,322,647
Total Domestic Group	$1,782,734,535	$0	$174,357,328	$28,061,282	$66,434,910	$1,090,111,905	$2,051,588,055	$3,141,699,960
Small Business Group								
GS	$146,944,296	$0	$14,371,638	$527,083	$4,579,428	$50,138,216	$166,422,445	$216,560,661
PLS	$240,705,291	-$646	$23,542,590	$834,648	$8,460,175	$126,538,716	$273,542,058	$400,080,774
OGS	$1,034,287	$0	$101,157	$2,837	$30,429	$270,259	$1,168,710	$1,438,969
UC	$9,168,128	$0	$896,673	$30,877	$293,024	$3,468,373	$10,388,702	$13,857,075
TOU-EO	$44,954,600	$0	$4,396,708	$143,565	$1,575,148	$23,418,567	$51,070,021	$74,488,588
Total Small Business Group	$442,806,602	-$646	$43,308,766	$1,539,010	$14,938,204	$203,834,131	$502,591,936	$706,426,067
Medium Business Group								
PLM	$710,240,598	-$11,194	$69,462,782	$2,275,805	$27,557,218	$493,652,745	$809,525,209	$1,303,177,954
TOU-MB	$27,054,763	$0	$2,646,045	$90,409	$1,086,575	$20,506,236	$30,877,792	$51,384,028
TOU-GSD	$23,720,951	-$5,819	$2,319,418	$53,387	$893,236	$15,259,851	$26,981,173	$42,241,024
Total Medium Business Group	$761,016,312	-$17,013	$74,428,245	$2,419,601	$29,537,029	$529,418,832	$867,384,174	$1,396,803,006
Large Business Group								
PLL	$176,002,156	-$83,951	$17,205,382	$493,494	$7,521,900	$154,570,901	$201,138,981	$355,709,882
TOU-SSD	$2,179,315	-$1,900	$212,958	$1,905	$87,980	$1,680,329	$2,480,258	$4,160,587
TOU-MLM	$18,028,223	-$50,329	$1,758,297	$20,036	$906,248	$22,193,886	$20,662,475	$42,856,361
TOU-HLF	$4,126,889	$0	$403,623	$13,899	$196,476	$4,550,451	$4,740,887	$9,291,338
TOU-RN from FPA	$68,071,831	-$562,518	$5,406,522	$56,684	$3,450,462	$70,994,361	$76,422,981	$147,417,342
TOU-RN from MAM	$431,073	$0	$42,160	$1,452	$18,025	$359,685	$492,710	$852,395
Total Large Business Group	$268,839,487	-$698,698	$25,028,942	$587,470	$12,181,091	$254,349,613	$305,938,292	$560,287,905
Agricultural Group								
5AS	$1,011,997	$0	$98,977	$2,771	$44,129	$928,965	$1,157,874	$2,086,839
APS,TOU-FS,IOP	$6,556,481	$0	$641,246	$16,584	$273,637	$5,452,295	$7,487,948	$12,940,243
Total Agricultural Group	$7,568,478	$0	$740,223	$19,355	$317,766	$6,381,260	$8,645,822	$15,027,082
Government/Institutional Group								
SCH	$22,010,169	$0	$2,152,667	$74,127	$839,792	$14,636,935	$25,076,755	$39,713,690
SLM	$68,911,052	$0	$6,739,729	$232,081	$3,311,851	$77,422,366	$79,194,713	$156,617,079
TC	$637,969	$0	$62,395	$0	$64,442	$2,282,657	$764,806	$3,047,463
G	$5,884,579	-$11,709	$574,386	$14,433	$281,093	$6,550,063	$6,742,782	$13,292,845
Total Government/Institutional Group	$97,443,769	-$11,709	$9,529,177	$320,641	$4,497,178	$100,892,021	$111,779,056	$212,671,077
Outdoor Lighting Group								
EOL	$19,514,043	$0	$1,908,538	$80,601	$825,873	$16,726,376	$22,329,055	$39,055,431
OLG	$54,964,296	$0	$5,375,690	$0	$1,690,687	$17,921,750	$62,030,673	$79,952,423
OLNG	$37,536,690	$0	$3,671,212	$212,986	$1,144,136	$11,541,064	$42,565,024	$54,106,088
Total Outdoor Lighting Group	$112,015,029	$0	$10,955,440	$293,587	$3,660,696	$46,189,190	$126,924,752	$173,113,942
Marginally Priced Group								
RTP-DA	$408,065,659	-$1,244,538	$32,749,758	$648,776	$21,451,100	$552,749,520	$461,670,755	$1,014,420,275
CBL	$336,097,824	-$1,244,538	$32,749,758	$648,776	$17,667,912	$310,848,634	$385,919,732	$696,768,366
Incremental	$71,967,835	$0	$0	$0	$3,783,188	$241,900,886	$75,751,023	$317,651,909
RTP-HA	$222,360,786	-$4,377,034	$16,874,079	$98,787	$15,345,106	$475,366,720	$250,301,724	$725,668,444
CBL	$176,907,804	-$4,377,034	$16,874,079	$98,787	$12,208,398	$268,681,761	$201,712,034	$470,393,795
Incremental	$45,452,982	$0	$0	$0	$3,136,708	$206,684,958	$48,589,690	$255,274,648
FPA	$75,596,572	-$624,699	$6,004,165	$62,950	$3,831,881	$112,093,022	$84,870,869	$196,963,891
TOU-SC	$12,184,206	$0	$1,191,656	$33,815	$662,584	$17,261,254	$14,072,261	$31,333,515
Total Marginally Priced Group	$718,207,223	-$6,246,271	$56,819,658	$844,328	$41,290,671	$1,157,470,516	$810,915,609	$1,968,386,125
Total	$4,190,631,435	-$6,974,337	$395,167,779	$34,085,274	$172,857,545	$3,388,647,468	$4,785,767,696	$8,174,415,164

1/ Per M.F.R. Item F-4

Georgia Power Company
Company Proposed Revenue Distribution

Class	Present Revenue 1/							
	Base Revenue	ILR	ECCR	DSM	Franchise Fee	Fuel Revenue	Total Rev Less Fuel	Total Rev
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Domestic Group								
R, RM	$1,520,171,623	$0	$93,104,431	$2,384,888	$56,828,976	$1,082,386,623	$1,672,489,918	$2,754,876,541
TOU-REO	$10,895,550	$0	$667,309	$16,928	$406,623	$7,725,282	$11,986,410	$19,711,692
Total Domestic Group	$1,531,067,173	$0	$93,771,740	$2,401,816	$57,235,599	$1,090,111,905	$1,684,476,328	$2,774,588,233
Small Business Group								
GS	$126,214,475	$0	$7,730,132	$0	$3,877,336	$50,138,216	$137,821,943	$187,960,159
PLS	$206,755,764	-$646	$12,662,964	$0	$7,286,902	$126,538,716	$226,704,984	$353,243,700
OGS	$888,380	$0	$54,410	$0	$25,550	$270,259	$968,340	$1,238,599
UC	$7,874,759	$0	$482,297	$0	$249,079	$3,468,373	$8,606,135	$12,074,508
TOU-EO	$38,612,774	$0	$2,364,878	$0	$1,356,378	$23,418,567	$42,334,030	$65,752,597
Total Small Business Group	$380,346,152		$23,294,681	$0	$12,795,245	$203,834,131	$416,435,432	$620,269,563
Medium Business Group								
PLM	$610,046,032	-$11,194	$37,362,194	$0	$24,033,931	$493,652,745	$671,430,963	$1,165,083,708
TOU-MB	$23,238,117	$0	$1,423,242	$0	$951,365	$20,506,236	$25,612,724	$46,118,960
TOU-G5D	$20,374,598	-$5,819	$1,247,506	$0	$776,722	$15,259,851	$22,393,007	$37,652,858
Total Medium Business Group	$653,658,747	-$17,013	$40,032,942	$0	$25,762,018	$529,418,832	$719,436,694	$1,248,855,526
Large Business Group								
PLL	$151,173,302	-$83,951	$9,253,618	$0	$6,633,031	$154,570,901	$166,976,000	$321,546,901
TOU-S5D	$1,871,875	-$1,900	$114,528	$0	$77,192	$1,680,329	$2,061,695	$3,742,024
TOU-MLM	$15,484,842	-$50,329	$945,302	$0	$812,478	$22,193,886	$17,192,293	$39,386,179
TOU-HLF	$3,544,707	$0	$217,099	$0	$175,081	$4,550,451	$3,936,887	$8,487,338
TOU-RN from FPA	$47,850,173	-$460,358	$2,902,437	$0	$2,554,660	$70,994,361	$52,846,911	$123,841,272
TOU-RN from MAM	$370,262	$0	$22,677	$0	$15,853	$359,685	$408,792	$768,477
Total Large Business Group	$220,295,161	-$596,538	$13,455,661	$0	$10,268,295	$254,349,613	$243,422,578	$497,772,191
Agricultural Group								
SAS	$869,227	$0	$53,236	$0	$38,996	$928,965	$961,459	$1,890,424
AP5,TOU-FS,IOP	$5,631,585	$0	$344,912	$0	$240,725	$5,452,295	$6,217,222	$11,669,517
Total Agricultural Group	$6,500,812	$0	$398,148	$0	$279,721	$6,381,260	$7,178,681	$13,559,941
Government/Institutional Group								
SCH	$18,905,166	$0	$1,157,866	$0	$730,885	$14,636,935	$20,793,917	$35,430,852
SLM	$59,189,672	$0	$3,625,131	$0	$2,953,815	$77,422,366	$65,768,618	$143,190,984
TC	$547,970	$0	$33,561	$0	$60,328	$2,282,657	$641,859	$2,924,516
G	$5,052,904	-$11,709	$308,753	$0	$250,650	$6,550,063	$5,600,598	$12,150,661
Total Government/Institutional Group	$83,695,712	-$11,709	$5,125,311	$0	$3,995,678	$100,892,021	$92,804,992	$193,697,013
Outdoor Lighting Group								
EOL	$16,767,993	$0	$1,026,972	$0	$727,123	$16,726,376	$18,522,088	$35,248,464
OLG	$47,215,159	$0	$2,891,740	$0	$1,432,887	$17,921,750	$51,539,786	$69,461,536
OLNG	$32,248,728	$0	$1,975,106	$0	$963,946	$11,541,064	$35,187,780	$46,728,844
Total Outdoor Lighting Group	$96,231,880	$0	$5,893,818	$0	$3,123,956	$46,189,190	$105,249,654	$151,438,844
Marginally Priced Group								
RTP-DA	$360,760,831	-$1,244,538	$17,611,193	$0	$19,585,999	$552,749,520	$396,713,485	$949,463,005
CBL	$288,792,995	-$1,244,538	$17,611,193	$0	$15,678,807	$310,848,634	$320,838,457	$631,687,091
Incremental	$71,967,835	$0	$0	$0	$3,907,192	$241,900,886	$75,875,027	$317,775,913
RTP-HA	$197,452,694	-$4,377,034	$9,041,299	$0	$14,269,839	$475,366,720	$216,386,798	$691,753,518
CBL	$151,999,713	-$4,377,034	$9,041,299	$0	$10,984,967	$268,681,761	$167,648,945	$436,330,706
Incremental	$45,452,982	$0	$0	$0	3284871.524	$206,684,958	$48,737,854	$255,422,812
FPA	$75,550,655	-$726,859	$4,582,658	$0	$4,033,553	$112,093,022	$83,440,008	$195,533,030
TOU-SC	$10,465,355	$0	$640,961	$0	$597,506	$17,261,254	$11,703,822	$28,965,076
Total Marginally Priced Group	$644,229,535	-$6,348,431	$31,876,111	$0	$38,486,897	$1,157,470,516	$708,244,113	$1,865,714,629
Total	$3,616,025,172	-$6,973,691	$213,848,412	$2,401,816	$151,947,409	$3,388,647,468	$3,977,249,118	$7,365,895,940

1/ Per M.F.R. Item F-4

Georgia Power Company
Staff Proposed Customer Class
Revenue Distribution

Customer Class	Present Base Revenue	Percent of System Incr.	Percent Increase	Revenue Increase	Total Base Revenues	ECCR Revenue 1/	ILR Revenue 2/	DSM Revenue 3/	Fuel Revenue 2/	MFF Revenue 4/	Total Revenue
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Domestic Group											
R, RM	$1,520,171,623	111%	17.50%	$265,973,743	$1,786,145,366	$175,617,577	$0	$27,861,612	$1,082,386,623	$70,306,134	$3,142,317,312
TOU-REO	$10,895,550	111%	17.50%	$1,906,318	$12,801,868	$1,258,707	$0	$199,670	$7,725,282	$503,161	$22,488,688
Total Domestic Group	$1,531,067,173			$267,880,061	$1,798,947,234	$176,876,283	$0	$28,061,282	$1,090,111,905	$70,809,296	$3,164,806,000
Small Business Group											
GS	$126,214,475	100%	15.77%	$19,904,685	$146,119,160	$14,366,744	$0	$527,083	$50,138,216	$4,832,412	$215,983,615
PLS	$206,755,764	80%	12.62%	$26,085,175	$232,840,939	$22,893,412	($646)	$834,648	$126,538,716	$8,767,799	$391,874,868
OGS	$888,380	80%	12.62%	$112,082	$1,000,462	$98,368	$0	$2,837	$270,259	$31,398	$1,403,323
UC	$7,874,759	75%	11.83%	$931,418	$8,806,177	$865,842	$0	$30,877	$3,468,373	$301,438	$13,472,707
TOU-EO	$38,612,774	80%	12.62%	$4,871,550	$43,484,324	$4,275,470	$0	$143,565	$23,418,567	$1,632,276	$72,954,202
Total Small Business Group	$380,346,152			$51,904,909	$432,251,061	$42,499,835	$0	$1,539,010	$203,834,131	$15,565,323	$695,688,715
Medium Business Group											
PLM	$610,046,032	85%	13.40%	$81,776,341	$691,822,373	$68,021,434	($11,194)	$2,275,805	$493,652,745	$28,739,385	$1,284,500,548
TOU-MB	$23,238,117	90%	14.19%	$3,298,296	$26,536,413	$2,609,116	$0	$90,409	$20,506,236	$1,138,401	$50,880,574
TOU-GSD	$20,374,598	75%	11.83%	$2,409,886	$22,784,484	$2,240,218	($5,819)	$53,387	$15,259,851	$923,042	$41,255,163
Total Medium Business Group	$653,658,747			$87,484,522	$741,143,269	$72,870,768	($17,013)	$2,419,601	$529,418,832	$30,800,828	$1,376,636,286
Large Business Group											
PLL	$151,173,302	90%	14.19%	$21,456,741	$172,630,043	$16,973,350	($83,951)	$493,494	$154,570,901	$7,886,155	$352,469,992
TOU-SSD	$1,871,875	75%	11.83%	$221,403	$2,093,278	$205,816	($1,900)	$1,905	$1,680,329	$91,073	$4,070,501
TOU-MLM	$15,484,842	100%	15.77%	$2,442,041	$17,926,883	$1,762,609	($50,329)	$20,036	$22,193,886	$957,851	$42,810,936
TOU-HLF	$3,544,707	110%	17.35%	$614,921	$4,159,628	$408,983	$0	$13,899	$4,550,451	$209,017	$9,341,978
TOU-RN from FPA	$47,850,173	115%	18.14%	$8,678,157	$56,528,330	$5,557,984	($460,358)	$56,684	$70,994,361	$3,036,450	$135,713,451
TOU-RN from MAM	$370,262	90%	14.19%	$52,553	$422,815	$41,572	$0	$1,452	$359,685	$18,893	$844,417
Total Large Business Group	$220,295,161			$33,465,815	$253,760,976	$24,950,314	($596,538)	$587,470	$254,349,613	$12,199,439	$545,251,275
Agricultural Group											
SAS	$869,227	125%	19.71%	$171,352	$1,040,579	$102,312	$0	$2,771	$928,965	$47,480	$2,122,107
APS,TOU-FS,IOP	$5,631,585	125%	19.71%	$1,110,163	$6,741,748	$662,863	$0	$16,584	$5,452,295	$294,623	$13,168,113
Total Agricultural Group	$6,500,812			$1,281,515	$7,782,327	$765,175	$0	$19,355	$6,381,260	$342,103	$15,290,220
Government/Institutional Group											
SCH	$18,905,166	80%	12.62%	$2,385,155	$21,290,321	$2,093,309	$0	$74,127	$14,636,935	$871,836	$38,966,529
SLM	$59,189,672	125%	19.71%	$11,668,152	$70,857,824	$6,966,891	$0	$232,081	$77,422,366	$3,558,300	$159,037,462
TC	$547,970	125%	19.71%	$108,022	$655,992	$64,499	$0	$0	$2,282,657	$68,730	$3,071,878
G	$5,052,904	115%	18.14%	$916,400	$5,969,304	$586,915	($11,709)	$14,433	$6,550,063	$300,013	$13,409,018
Total Government/Institutional Group	$83,695,712			$15,077,729	$98,773,441	$9,711,613	($11,709)	$320,641	$100,892,021	$4,798,880	$214,484,887
Outdoor Lighting Group											
EOL	$16,767,993	85%	13.40%	$2,247,740	$19,015,733	$1,869,667	$0	$80,601	$16,726,376	$862,629	$38,555,006
OLG	$47,215,159	85%	13.40%	$6,329,167	$53,544,326	$5,264,591	$0	$0	$17,921,750	$1,756,060	$78,486,727
OLNG	$32,248,728	85%	13.40%	$4,322,925	$36,571,653	$3,595,802	$0	$212,986	$11,541,064	$1,188,277	$53,109,782
Total Outdoor Lighting Group	$96,231,880			$12,899,832	$109,131,712	$10,730,060	$0	$293,587	$46,189,190	$3,806,966	$170,151,514
Marginally Priced Group											
RTP-DA											
CBL	$288,792,995	94%	14.83%	$42,822,521	$331,615,516	$32,605,136	($1,244,538)	$648,776	$310,848,634	$15,436,020	$689,909,545
Incremental	$71,967,835			$11,617,650 5/	$83,585,485				$241,900,886	$1,912,940	$327,399,311
RTP-HA											
CBL	$151,999,713	97%	15.35%	$23,331,405	$175,331,118	$17,238,925	($4,377,034)	$98,787	$268,681,761	$10,458,310	$467,431,867
Incremental	$45,452,982			$11,240,571 5/	$56,693,553				$206,684,958	$1,297,490	$264,676,001
FPA	$75,550,655	115%	18.14%	$13,701,945	$89,252,600	$5,704,077	($726,859)	$62,950	$112,093,022	$4,723,351	$211,109,141
TOU-SC	$10,465,355	115%	18.14%	$1,898,008	$12,363,363	$1,215,592	$0	$33,815	$17,261,254	$706,584	$31,580,607
Total Marginally Priced Group	$526,808,718			$81,753,879	$748,841,635	$56,763,731	($6,348,431)	$844,328	$1,157,470,515	$34,534,695	$1,992,106,472
Total	$3,498,604,355			$283,868,202	$4,190,631,656	$395,167,779	($6,973,691)	$34,085,274	$3,388,647,467	$172,857,530	$8,174,415,369

1/ Customer class ECCR revenue calculated as the Company's proposed amount of $395,167,779 distributed to the customer classes based on the total base revenues in Column (5) less RTP incremental revenues, and 35% of FPA

2/ Per Company distribution to customer classes.

3/ Customer class distribution of the Company's proposed DSM revenue of $34,085,274 is the same as shown in the Company's proposal in Exhibit_(GAW-10), page 4. The ultimate distribution will depend on the Commission

4/ Customer class MFF revenue calculated as the Company's proposed amount of $172,857,530 distributed to the customer classes based on the sum of the base revenues (Column (5)), ECCR revenue (Column (6)), ILR revenue

5/ RTP-DA and RTP-HA reliability capacity component revenue increase, respectively, of $11,617,650 and $11,240,591, based on the Company's determinations of incremental KWH usage per Georgia Power response in

Georgia Power Company
Staff Proposed Customer Class
Revenue Distribution

Determination of RTP CBL Increase 1/

	(1)	(2)	(3)	(4)	(5)
	Rate Schedule	Current Revenue	Pct of Total	Incr. Pct. of Sys. Avg	Percent Increase
RTP-HA					
IND	FPA	$0.000	0.00%	115%	0.00%
Comm	FPA	$2,611.164	1.92%	115%	2.20%
IND	MLM	$84,052.309	61.67%	100%	61.67%
Comm	MLM	$9,485.651	6.96%	100%	6.96%
IND	PLL	$34,056.694	24.99%	90%	22.49%
Comm	PLL	$5,818.832	4.27%	90%	3.84%
Comm	PLM	$133.781	0.10%	85%	0.08%
IND	PLM	$144.988	0.11%	85%	0.09%
Comm	SCH	$0.000	0.00%	80%	0.00%
Comm	SLM	$0.000	0.00%	125%	0.00%
IND	TOU	$0.000	0.00%	0	0.00%
Total RTP-HA		**$136,303.419**	**100.00%**		**97.33%**
RTP-DA					
Comm	APS	$0.000	0.00%	125%	0.00%
IND	APS	$177.014	0.05%	125%	0.06%
IND	FPA	$3,440.717	1.01%	115%	1.16%
Comm	FPA	$7,379.582	2.16%	115%	2.49%
Comm	GOV	$8,757.985	2.57%	115%	2.95%
IND	GOV	$0.000	0.00%	115%	0.00%
Comm	GSD	$4,502.825	1.32%	75%	0.99%
IND	GSD	$3,979.526	1.17%	75%	0.87%
Comm	HLF	$14,204.078	4.16%	110%	4.58%
IND	MLM	$67,466.071	19.77%	100%	19.77%
Comm	MLM	$17,273.702	5.06%	100%	5.06%
Comm	PLL	$80,393.566	23.56%	90%	21.21%
IND	PLL	$75,048.158	22.00%	90%	19.80%
Comm	PLM	$39,030.319	11.44%	85%	9.72%
IND	PLM	$10,131.707	2.97%	85%	2.52%
Comm	SCH	$4,153.981	1.22%	80%	0.97%
Comm	SLM	$4,784.887	1.40%	125%	1.75%
Comm	SSD	$456.819	0.13%	75%	0.10%
IND	TEO	$9.078	0.00%	80%	0.00%
Comm	TEO	$5.236	0.00%	80%	0.00%
Total RTP-DA		**$341,195.251**	**100.00%**		**94.02%**

1/ Current Revenue per Exhibit GAW-6 in 2006 Georgia Power Rate Case

Georgia Power Company
Staff Revenue Increase Comparison
Base Revenue + ECCR + ILR

	Increase ($000)		Pct. Increase	
Customer Class	**Staff**	**Company**	**Staff**	**Company**
Domestic Group				
R, RM	$348,487	$329,890	21.60%	20.45%
TOU-REO	$2,498	$2,363	21.60%	20.43%
Total Domestic Group	**$350,985**	**$332,253**	**21.60%**	**20.45%**
Small Business Group				
GS	$26,541	$27,371	19.82%	20.43%
PLS	$36,316	$44,829	16.55%	20.43%
OGS	$156	$193	16.55%	20.43%
UC	$1,315	$1,708	15.73%	20.43%
TOU-EO	$6,782	$8,374	16.55%	20.43%
Total Small Business Group	**$71,110**	**$82,475**	**17.62%**	**20.43%**
Medium Business Group				
PLM	$112,436	$132,295	17.37%	20.43%
TOU-MB	$4,484	$5,039	18.18%	20.43%
TOU-GSD	$3,403	$4,418	15.74%	20.44%
Total Medium Business Group	**$120,322**	**$141,753**	**17.35%**	**20.44%**
Large Business Group				
PLL	$29,176	$32,781	18.20%	20.44%
TOU-SSD	$313	$406	15.76%	20.45%
TOU-MLM	$3,259	$3,356	19.90%	20.49%
TOU-HLF	$807	$769	21.45%	20.43%
TOU-RN from FPA	$11,334	$22,624	22.54%	44.98%
TOU-RN from MAM	$71	$80	18.18%	20.43%
Total Large Business Group	**$44,960**	**$60,015**	**19.28%**	**25.74%**
Agricultural Group				
SAS	$220	$189	23.90%	20.44%
APS,TOU-F5,IOP	$1,428	$1,221	23.90%	20.43%
Total Agricultural Group	**$1,649**	**$1,410**	**23.90%**	**20.43%**
Government/Institutional Group				
SCH	$3,321	$4,100	16.55%	20.43%
5LM	$15,010	$12,836	23.90%	20.43%
TC	$139	$119	23.90%	20.43%
G	$1,195	$1,097	22.33%	20.51%
Total Government/Institutional Group	**$19,664**	**$18,152**	**22.14%**	**20.44%**
Outdoor Lighting Group				
EOL	$3,090	$3,628	17.37%	20.39%
OLG	$8,702	$10,233	17.37%	20.42%
OLNG	$5,944	$6,984	17.37%	20.41%
Total Outdoor Lighting Group	**$17,736**	**$20,845**	**17.37%**	**20.41%**
Marginally Priced Group				
RTP-DA				
CBL	$57,816	$62,443	18.95%	20.46%
Incremental	$11,618	$0	16.14%	0.00%
RTP-HA				
CBL	$31,529	$32,741	20.13%	20.90%
Incremental	$11,241	$0	24.73%	0.00%
FPA	$14,823	$1,570	18.67%	1.98%
TOU-SC	$2,473	$2,270	22.26%	20.43%
Total Marginally Priced Group	**$129,500**	**$99,023**	**19.34%**	**14.78%**
Total	**$755,926**	**$755,926**	**19.77%**	**19.77%**

Georgia Power Company
Staff Revenue Increase Comparison
Total Revenue

Customer Class	Increase ($000) Staff	Increase ($000) Company	Pct. Increase Staff	Pct. Increase Company
Domestic Group				
R, RM	$387,441	$364,501	14.06%	13.23%
TOU-REO	$2,777	$2,611	14.09%	13.25%
Total Domestic Group	**$390,218**	**$367,112**	**14.06%**	**13.23%**
Small Business Group				
GS	$28,023	$28,601	14.91%	15.22%
PLS	$38,631	$46,837	10.94%	13.26%
OGS	$165	$200	13.30%	16.18%
UC	$1,398	$1,783	11.58%	14.76%
TOU-EO	$7,202	$8,736	10.95%	13.29%
Total Small Business Group	**$75,419**	**$86,157**	**12.16%**	**13.89%**
Medium Business Group				
PLM	$119,417	$138,094	10.25%	11.85%
TOU-MB	$4,762	$5,265	10.32%	11.42%
TOU-GSD	$3,602	$4,588	9.57%	12.19%
Total Medium Business Group	**$127,781**	**$147,947**	**10.23%**	**11.85%**
Large Business Group				
PLL	$30,923	$34,163	9.62%	10.62%
TOU-SSD	$328	$419	8.78%	11.19%
TOU-MLM	$3,425	$3,470	8.70%	8.81%
TOU-HLF	$855	$804	10.07%	9.47%
TOU-RN from FPA	$11,872	$23,576	9.59%	19.04%
TOU-RN from MAM	$76	$84	9.88%	10.92%
Total Large Business Group	**$47,479**	**$62,516**	**9.54%**	**12.56%**
Agricultural Group				
SAS	$232	$196	12.26%	10.39%
APS,TOU-FS,IOP	$1,499	$1,271	12.84%	10.89%
Total Agricultural Group	**$1,730**	**$1,467**	**12.76%**	**10.82%**
Government/Institutional Group				
SCH	$3,536	$4,283	9.98%	12.09%
SLM	$15,846	$13,426	11.07%	9.38%
TC	$147	$123	5.04%	4.20%
G	$1,258	$1,142	10.36%	9.40%
Total Government/Institutional Group	**$20,788**	**$18,974**	**10.73%**	**9.80%**
Outdoor Lighting Group				
EOL	$3,307	$3,807	9.38%	10.80%
OLG	$9,025	$10,491	12.99%	15.10%
OLNG	$6,381	$7,377	13.66%	15.79%
Total Outdoor Lighting Group	**$18,713**	**$21,675**	**12.36%**	**14.31%**
Marginally Priced Group				
RTP-DA				
CBL	$58,222	$65,081	9.22%	10.30%
Incremental	$9,623	-$124	3.03%	-0.04%
RTP-HA				
CBL	$31,101	$34,063	7.13%	7.81%
Incremental	$9,253	-$148	3.62%	-0.06%
FPA	$15,576	$1,431	7.97%	0.73%
TOU-SC	$2,616	$2,368	9.03%	8.18%
Total Marginally Priced Group	**$126,392**	**$102,671**	**6.77%**	**5.50%**
Total	**$808,519**	**$808,519**	**10.98%**	**10.98%**