DIRECT TESTIMONY OF
ANN P. DAISS AND ROBERT B. MORRIS
ON BEHALF OF GEORGIA POWER COMPANY
GPSC DOCKET NO. 31958

I. INTRODUCTION

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

A. Ann P. Daiss. I am the Comptroller for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

Q. MS. DAISS, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I graduated summa cum laude from the University of Georgia in March 1989 with a Bachelors of Business Administration degree in Accounting. I began my employment in the Audit Division of Arthur Andersen and progressed through staff, senior and manager positions. In September 1998, I joined Southern Company Services ("SCS"). As part of the Southern Company Comptroller organization, I was Director of SCS Accounting, Director of Special Projects, and, for approximately five years, I was Director of Accounting and Assistant Comptroller, where my primary responsibilities related to the preparation and oversight of the consolidated financial statements and the filing, with the Securities and Exchange Commission, of the annual and quarterly financial reports for Southern Company and its registrant subsidiaries. In March 2006, I assumed the position of Vice President, Comptroller and Chief Accounting Officer of Georgia Power. I am also a Certified Public Accountant.

As Comptroller, I am responsible for the financial and regulatory accounting functions of the Company. My duties include overseeing the corporate accounting records in

accordance with generally accepted accounting principles and various regulatory requirements, and the preparation and filing of financial and regulatory reports, including rate cases.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified in Georgia Power's last base rate case in 2007 in Docket No. 25060 (the "2007 Rate Case"), in several fuel cases, as well as in other hearings related to the nuclear accounting order, municipal franchise fees, and the certifications of Plant McDonough Units 4, 5 and 6, and Plant Vogtle Units 3 and 4.

Q. MR. MORRIS, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received my Bachelor of Business Administration in Accounting from Georgia State University in 1978 and was employed as a Staff Accountant by the firm of Jones & Kolb, Certified Public Accountants. I am a Certified Public Accountant as well as a 2005 graduate of the Emory University Executive Program. I began my career with Georgia Power in 1981 as a Staff Accountant in Tax Accounting and Compliance. Subsequently, I have held various positions in the Company's Accounting Department, including Manager of Tax Accounting and Compliance, Fixed Asset Manager, and Accounting Services General Manager. I was promoted to Assistant Comptroller in 2005 and am responsible for managing the corporate accounting process to insure compliance with generally accepted accounting principles and various regulatory requirements and the preparation and filing of financial reports and regulatory filings.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION ON PREVIOUS MATTERS?

A. Yes. I testified in Docket No. 27800, Georgia Power's certification of Plant Vogtle Units 3 and 4, as a rebuttal witness in the 2007 Rate Case, and in Docket No. 22202 related to the merger of Georgia Power and Savannah Electric and Power Company.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to support the Company's filing in this docket, including the calculation of the test period revenue requirement. This filing is being made as required by the Commission in its December 31, 2007 order in Docket No. 25060 (the "2007 Rate Case Order") so that the Commission may consider whether to continue, modify, or discontinue the rate plan contained in the 2007 Rate Case Order. That rate plan was altered by the Commission's September 16, 2009 Order in Docket No. 25060 (the "2009 Order") in which the Commission allowed the Company's request to amortize the regulatory liability for other costs of removal in 2009 and 2010. The 2009 Order also altered the Company's maximum end of the earnings range allowed by the Commission. Together, these orders (the "Current Accounting Orders") provide the rate plan under which the Company is currently operating. In our testimony, we demonstrate that the Company's revenues under its current rates are not adequate to cover the Company's cost of service and we propose modifications to the Current Accounting Orders, as well as certain new tariffs.

Q. WHAT HAVE RETAIL EARNINGS BEEN UNDER THE CURRENT ACCOUNTING ORDERS?

A. The Company reported a return on equity ("ROE") of 12.20 percent and 9.75 percent for the twelve months ended December 31, 2008 and 2009, respectively. The allowed ROE range under the 2007 Rate Case Order of 10.25 to 12.25 percent was modified in the 2009 Order to a maximum of 9.75 percent in 2009 and 10.15 percent in 2010.

Q. WHAT IS THE COMPANY'S CURRENT FINANCIAL STRENGTH?

A. The Company's current financial strength is good, as evidenced by the current A and A2 credit ratings by Standard and Poor's, Moody's and Fitch. However, on September 1, 2009, Moody's lowered the credit rating outlook for Georgia Power as well as all the operating subsidiaries of Southern Company from stable to negative. A portion of their reasoning is as follows:

> "Georgia Power's negative rating outlook considers cash flow metrics that are weak for its rating category and those of its peer utilities as well as increasing business and operating risk associated with the proposed expansion at the Vogtle plant, which is expected to increase the company's capital expenditures "considerably" over the next several years…building a new nuclear plant is a complex and risky endeavor during construction and may result in some modest rating pressure over the construction period…"[1]

On September 3, 2009, Fitch Ratings also affirmed the ratings for Georgia Power, but revised the Ratings Outlook from stable to negative citing the following reasons:

> "…expectation of declining credit metrics through 2010, pressure on cash flows…as a result of the economic downturn, and rising capital expenditures."[2]

In addition, in response to the question, "what could trigger a downgrade?" Fitch responded as follows:

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[1] Jason Lehmann, *Moody's Changes Southern Co., Subsidiaries' Credit Rating Outlooks to Negative*, SNL Interactive, Sept. 1, 2009, http://www.snl.com/Interactivex/article.aspx?CdId=A-9996533-9566; Global Credit Research, Moody's Investor Service, Credit Opinion: Southern Company (Sept. 2, 2009)

[2] FitchRatings, Georgia Power Company (Oct. 19, 2009)

"A less-than-constructive base rate decision in GPC's next base rate review,...would likely result in a one-notch downgrade."[3]

As recently as June 17, 2010, Moody's announced that Georgia Power was one of three operating subsidiaries of Southern Company on review for a possible downgrade. Again, Moody's cited cash flow metrics below Moody's acceptable parameters for Georgia Power's current rating category and risk profile. Among the risks contributing to the review are the nuclear construction program, possible carbon legislation and renewable portfolio standards, as well as the Company's prospects for obtaining significant rate relief in this case.

With the largest capital expenditure budget in the Company's history over the next several years, the Company will have to repeatedly access the capital markets to fund these investments. This additional financing must be sought in a highly competitive marketplace in which many utilities and other companies will also be seeking capital and in which investors will have numerous other opportunities to earn the returns they seek. We must remain financially healthy in order to attract investment at reasonable costs, and the rating agencies have indicated, as shown above, that they are closely watching the Company's financial health. Rating agencies base their assessment of the Company on metrics that test the Company's cash flow in relation to debt and operation costs, often referred to as "coverage ratios," among other metrics. We believe that the revenues requested in this case will satisfy those metrics and maintain the Company's "A" credit ratings.

Q. IS THE COMPANY REQUESTING TO INCREASE RATES?

A. Yes. As explained above and by Mr. Garrett in his testimony, the rates established by the 2007 Rate Case Order are no longer sufficient to allow the Company to recover the costs of continuing to provide safe, reliable and cost effective retail electric service in a manner

[3] Id.

that maintains customer satisfaction levels and earns a fair return on its investments. The Commission's 2009 Order and cautionary statements from rating agencies serve as reminders of the Company's current financial condition.

Q. PLEASE DESCRIBE THE REASONS FOR THE PROPOSED INCREASE IN RATES.

A. Since the 2007 Rate Case, average retail electric plant in service has increased from $22.1 billion in 2008 to $23.7 billion in 2009, an increase of over $1.3 billion. This significant increase in retail rate base is primarily in the form of environmental controls, transmission and distribution investments. While the Company has diligently worked to control costs, the increases in investment necessary to meet federal and state mandated environmental controls as well as to maintain reliable service for our customers, have been dramatic; therefore, an increase in revenues is needed to maintain the Company's financial integrity and to allow it to attract new capital to meet its growing infrastructure needs.

Further, since the 2007 Rate Case, the Company and its customers have faced unprecedented challenges to the operational and financial well-being of the Company and its customers, including the most significant economic recession since the Great Depression. In addition, the Company and the electric utility industry as a whole continue to face changing environmental regulation and legislation. Such challenges come as we are in the midst of the largest construction program in the Company's history. Before reflecting the extended Plant McDonough construction schedule recently approved by the Commission, the Company's construction program is currently estimated to be $2.5 billion for 2010, $2.4 billion for 2011, and $2.8 billion for 2012. This is a large increase over the $1.8 billion spent annually on capital expenditures in 2007 and 2008.

The Company is also concerned with attracting capital. As explained by Dr. Vander Weide, increased uncertainty in the economy, changing legislation and regulation and their attendant effects on the economy, as well as increasing costs from a variety of sectors, all translate into challenges in attracting investment. The Company has proposed, through the testimony of Dr. Vander Weide, a fair return that will enable us to continue to raise capital on advantageous terms for the benefit of our customers and shareholders.

Q. DOES THE COMPANY PROPOSE TO CONTINUE THE RATE PLAN IMPLEMENTED BY THE CURRENT ACCOUNTING ORDERS?

A. Yes, with some enhancements and additions to fit the current economic climate. While the previous retail rate orders, dating from 1995, were prime examples of the Commission's development of incentive regulation that addressed specific situations and provided benefits to customers, those periods of predictable usage and expense patterns have been replaced with economic changes at a pace we have rarely ever seen. In this case, we propose an Alternate Rate Plan, the primary points of which are:

- Continuation of the traditional base rate tariffs with revisions for currently projected earnings, rate base and cost of capital, based on a calendar test year of 2011;

- Creation of an Adjustable Cost Recovery ("ACR") tariff that is designed to review the adequacy of the traditional base rate tariffs on a continuing and prospective basis; and provide a process for resetting base rates periodically;

- Continuation and enhancement of the Environmental Compliance Cost Recovery ("ECCR") tariff from the 2007 Rate Case;

- Creation of a new Certified Capacity Cost Recovery ("CCCR") tariff to manage the timing of recovery of costs related to new capacity additions certified by the

Commission and updated through applicable project construction monitoring reports and hearings;

- Continuation and enhancement of the Demand Side Management ("DSM") Residential tariff and creation of a DSM-Commercial tariff designed to recover all costs associated with Commission-approved DSM programs with annual reviews and a process for resetting the tariff after compliance review by the Commission;

- Implementation of an annual review of the Municipal Franchise Fee ("MFF") tariff to adjust for changes in relative gross receipts between customers served inside and outside municipal boundaries;

- Continuation of a plus or minus 100 basis point range ROE;

- Continuation of the Annual Surveillance Report process with two-thirds sharing of any earnings above the allowed ROE range refunded to customers and one-third retained by the Company; and

- Implementation of a symmetrical two-thirds and one-third sharing mechanism within the Annual Surveillance Report process if earnings are below the allowed ROE range.

The Alternate Rate Plan proposed by the Company in this case will maintain many of the features of the 2007 Rate Case Order. Our plan balances the interests of the Company and its customers, as it uses a combination of traditional tariffs and new tariffs designed to recover specific costs on a more timely basis, including cost recovery of new certified capacity additions, environmental controls, and Commission-approved DSM programs. Our plan also allows for changes in the projected pace of economic recovery.

Q. HOW WILL THE COMPANY'S ALTERNATE RATE PLAN BENEFIT YOUR CUSTOMERS?

A. Our customers will benefit in several ways from the Company's Alternate Rate Plan. First, by introducing new rates closer to the actual in-service date of new certified capacity, our customers would not be paying based on projections that may extend several years into the future, but rather be paying based on actual costs. Second, adjusting rates annually, or as needed, allows for a smaller and more gradual impact on customers. Levelizing revenue requirements over an extended period followed by a big "stair-step" increase (as with the ECCR tariff in this proceeding) is difficult for customers to incorporate into their budgets. In addition, by allowing for an annual review of the remaining base rate tariffs, the Company, its customers and the Commission will be better able to accommodate the many potential changes and challenges with which we are confronted.

Customers also benefit because the Company's plan allows the Company continued access to the capital markets at competitive rates and on a timely basis, and such access translates to lower costs for our customers. This contributes to the Company's overall financial stability, which allows us to maintain outstanding customer service, a hallmark of the Company.

Finally, the continuation of a sharing mechanism will benefit customers. We have designed the sharing mechanism included in our proposal much like the sharing mechanisms approved by the Commission prior to the 2007 Rate Case. Under our plan, customers receive the majority of any earnings above the band if the Company's performance is better than expected. For example, if the economy rebounds and demand increases more quickly than currently projected, earnings may increase. Likewise, an especially hot summer or cold winter could increase revenues and earnings. In such cases, customers could share in increased earnings under our plan; however, under a typical ratemaking order, the Company would be entitled to keep all such increased

earnings. Under our plan, the Company only receives the remaining third of any earnings above the band, which benefits both customers and the Company as it re-establishes the traditional incentive for the Company to continue to manage its costs at an optimum level. This approach has worked well in the past.

Q. WHAT IS THE COMPANY REQUESTING AS AN INCREASE IN BASE RATES FOR 2011?

A. Under the Alternate Rate Plan, the Company is requesting an increase to be collected through the traditional base tariffs of $451 million, to be effective January 1, 2011. This increase is based on a requested ROE of 11.95 percent and a return on rate base of 8.76 percent on a rate base of $12.69 billion. We have also proposed to recover specific costs through the ECCR, CCCR, DSM and MFF tariffs. Specifically, we are requesting increases of $115 million to be collected through the ECCR tariff, $32 million to be collected through the DSM tariff, and $17 million to be collected through the MFF tariff. These tariffs will be separately monitored and administered, as described in detail below. If the Commission does not approve our plan to utilize the ECCR, CCCR, DSM and MFF tariffs in the manner we have proposed, our rate increase request must still recover those costs through the traditional base tariffs. Combined, our request totals $615 million, which is an increase of 8.2 percent to total retail rates and will result in an increase of about $10.88, or 10.1 percent, on the monthly bill of a typical residential customer using 1,000 kWh per month

Please refer to Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1) page 1 of 14 to see the details and calculations that support the $451 million requested for recovery through the traditional base tariffs. Exhibit__(APD/RBM-1 Schedule 2 ECCR) supports the $115 million requested for recovery through the ECCR tariff and Exhibit___(APD/RBM-1 Schedule 4 DSM) supports the $32 million requested for recovery through the DSM tariff. Amounts recovered under the MFF tariff are based on amounts recovered under all

other tariffs as reflected in Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1) page 3 of 14.

Q. HAS THE COMPANY ESTIMATED THE BASE RATE IMPACTS OF THE ALTERNATE PLAN IN 2012 AND 2013?

A. Based on our 2010 budget, we currently project that the Company's earnings as shown in Exhibit___(APD/RBM-1, Schedule 1, Workpapers 2 and 3), would be slightly below the proposed ROE band in 2012, primarily as a result of the depreciation expense deferral described below, and would be within the band in 2013. However, we believe that updated budgets and revenue forecasts may eliminate the need for an ACR tariff adjustment in either year.

In addition, we currently estimate the ECCR tariff would increase by $120 million in 2012, primarily as a result of the expense deferral described below and would decrease by $12 million in 2013. The CCCR tariff would begin recovering the costs of Plant McDonough Units 4, 5 and 6 with increases of $99 million in February 2012, $77 million in June 2012, and $76 million in February 2013. Additional CCCR adjustments may be needed for other approved renewable projects and purchased power agreements, as well as for the conversion of Plant Mitchell Unit 3 to biomass. However, construction of these facilities has not yet begun and the ultimate timing is uncertain. The DSM tariffs would increase by $17 million in 2012 and $18 million in 2013 to reflect the terms of the stipulated agreement in the DSM Certification proceeding. Amounts recovered under the MFF tariff are based on amounts recovered under all other tariffs.

The details and calculations supporting each of these amounts are included in Exhibit___(APD/RBM-1, Schedule 2 ECCR, Schedule 3 CCCR, Schedule 4 DSM, Schedule 1 Workpaper 2 page 6 of 6, and Schedule 1, Workpaper 3 page 6 of 6). Please note, the trade secret version of Schedule 3 CCCR is being provided as Supplemental Item S-50 in the Minimum Filing Requirements ("MFRs") being filed in this proceeding.

Q. WHAT HAS BEEN DONE TO MINIMIZE THE REQUESTED INCREASE IN 2011?

A. In addition to continuing to operate as efficiently as possible, the Company has incorporated several significant proposals in order to minimize the immediate impact of the base rate request on our customers. While we are just beginning to see some positive events that allow us to be hopeful about the economic recovery in our state, we realize that an extended recession like the one our state and country are experiencing will continue to have a dramatic impact on our customers and their well-being. As a result, we have worked closely with the Commission to find ways to reduce the amount of the rate increase we would have otherwise needed in 2011 by approximately $250 million. The Company's requested revenue requirement includes the following reductions:

- An extension of the construction schedule and delayed the commercial in-service dates of McDonough Units 4, 5 and 6 in Docket No. 24506. This adjustment was the result of the joint efforts by the Company and the Commission to recognize and institute a solution that will benefit our customers until our state's economy returns to a more stable and sustainable footing, and results in a reduction in 2011 revenue requirements of $78 million;

- A one-year deferral of the $82 million increase in depreciation expense primarily related to transmission and distribution plant added since the 2007 base rate case;

- A one-year deferral of $78 million representing the depreciation and operation and maintenance expenses associated with the ECCR tariff; and

- A phase in of the $16 million of additional sums associated with DSM programs proposed in Docket No. 31081 (the "Company's 2010 IRP Proceeding") and 31082 ("the Company's 2010 DSM Certification Proceeding") such that no additional sum is recovered in 2011.

Q. WHAT OTHER STEPS HAS THE COMPANY TAKEN TO REDUCE THE REVENUE REQUIREMENTS IN THIS CASE?

A. In recognition of the difficult economic times that all customers are facing, the Company has closely evaluated the components of our revenue requirements to identify additional opportunities where there may be alternative approaches that allow recovery of some costs in a manner that also reduces immediate customer rate impacts. The results of this evaluation have been incorporated into our filing as follows:

- As described later in our testimony, we have removed certain nuclear decommissioning costs totaling $2.8 million from our 2011 request in recognition of license extensions received for the existing units, as well as the construction of new units that is now underway.

- In accordance with the Commission's 2009 Order, we are also proposing that the $65.7 million that was not amortized in 2009 be amortized as a reduction to revenue requirements over the three years beginning in January 2011, rather than over the remaining lives of the associated assets. We have also continued to review the Company's other costs of removal account and have identified an additional $26.8 million that we are proposing to reclassify as a regulatory liability and amortize as a further reduction to revenue requirements over the three years beginning in January 2011.

- Where reasonable and appropriate, we have proposed multi-year amortization periods to recover certain costs, rather than recovering them over shorter periods. Examples of these costs include approximately $56.4 million of expenses resulting from the recently enacted healthcare legislation that we have proposed to amortize over the twelve year period beginning in 2011, existing deferred environmental and DSM costs of approximately $37.6 million that we have proposed to amortize over three year periods beginning in 2011, and the proposed

deferrals of 2011 depreciation and environmental expenses described previously that we have proposed to recover over three year periods beginning in 2012.

In total, these adjustments have the effect of reducing the requested 2011 rate increase by over $100 million from what it otherwise might have been.

Q. PLEASE DESCRIBE THE ORGANIZATION OF THE REMAINDER OF YOUR TESTIMONY.

A. The next section of our testimony describes the new and enhanced cost recovery mechanisms discussed above, namely the ACR, ECCR, CCCR, DSM and MFF tariffs, as well as a proposed change to the accounting methodology for revenues collected under the Real Time Pricing ("RTP") tariff. Our testimony discusses the costs to be recovered by such tariffs and their impacts to the regulatory process, while Mr. Greg Roberts discusses the details of these tariffs in his testimony.

The third section of our testimony satisfies the requirements of the 2007 Rate Case Order, as it contains the details of the revenue requirement associated with the budgeted period twelve months ending July 31, 2011 and the components that comprise that revenue requirement. In addition, in response to the requirements from the 2007 Rate Case, we have included an exhibit that shows the expected rates of return and associated revenue requirements for the calendar year periods ending 2011, 2012 and 2013. Please note that the revenue requirements for all four budgeted periods exclude the costs proposed to be collected through the ECCR, CCCR, DSM and MFF tariffs which are described later. In the event the Commission does not approve any of these separate tariffs, the related revenue requirements would need to be added to the amounts proposed to be collected through the traditional tariffs. This section also contains the summary of projections, wholesale sales, taxes, and working capital applicable to the test year ending July 31, 2011, as well as the rates of return and revenue requirements applicable to the budgeted

years ending December 31, 2011, 2012 and 2013. The information is presented in a form similar to the Annual Surveillance Reports filed each year.

Q. PLEASE DESCRIBE THE EXHIBITS SUPPORTING YOUR TESTIMONY.

A. Exhibits___(APD/RBM) 1 through 3, contain the following:

- Exhibit___(APD/RBM-1) consists of six schedules demonstrating and supporting the calculation of the requested revenue requirement based on a test period ending December 31, 2011, Schedule 1 contains the calculation of the requested revenue requirement for the calendar year ending December 31, 2011 excluding ECCR, CCCR and DSM tariffs. Schedule 2 focuses on the projected revenue requirements related to the ECCR tariff for calendar years 2011, 2012 and 2013. Schedule 3 demonstrates the timing and revenue requirements related to the CCCR tariff as currently budgeted. Schedule 4 summarizes the revenue requirements related to the DSM tariff for calendar years 2011, 2012 and 2013. Schedule 5 shows the components and calculation of the 13-month weighted average cost of capital for the calendar year ending December 31, 2011, using an 11.95 percent ROE as recommended by Dr. James H. Vander Weide. Schedule 6 displays the details and the calculation of the weighted average cost of capital ending December 31, 2011, including a reconciliation of the budgeted balances to the adjusted balances used in calculating the retail revenue requirements.

- Exhibit___(APD/RBM-2) consists of seven schedules that demonstrate and support the projected financial statements, revenues, expenses and 13-month average rate base items as of December 31, 2011. The amounts reflected in these schedules are prior to additional adjustments for Commission-approved and Company-proposed treatments to reflect retail costs of service. Schedules 1, 2 and 3 are the as budgeted 13-month average balances for Electric Plant-In-Service, Accumulated Provision for Depreciation and Amortization, and Other Rate Base

Items, respectively. Schedule 4 supports the average balance of the components of Working Capital, including Materials and Supplies, Minimum Bank Balances, Prepayments and Petty Cash, and Cash Working Capital. Schedule 5 presents Taxes Other Than Income Taxes. Schedules 6 and 7 demonstrates various other components of earnings and rate base for the period ending December 31, 2011.

- Exhibit___(APD/RBM-3) is comprised of four schedules that calculate and support the computation of the retail revenue deficiency for the test period ending July 31, 2011. Schedule 1 shows the revenue deficiency related to the Company's traditional base tariffs and the MFF tariff, exclusive of the ECCR, CCCR and DSM tariffs applicable to this period. Schedule 2 summarizes the retail revenue requirement related to the ECCR tariff for the twelve months ending July 31, 2011. Schedule 3 shows the calculation of the retail revenue requirement for the DSM tariff. There is no separate CCCR tariff for this period since the Commission has approved the delay in the in-service dates of the McDonough Units. Schedule 4 is the Summary of Projections. This exhibit demonstrates the changes in revenues, expenses and rate base from the historic period, the year ended December 31, 2009, after adjustments as approved by the Commission in Docket No. 25060 to the test period ending July 31, 2011. The exhibit also displays the previously approved and proposed adjustments to arrive at the adjusted retail cost of service amounts and balances for the test period ending July 31, 2011. The remainder of the exhibit consists of the explanations for the changes between periods as well as the intra-period adjustments.

II. NEW TARIFFS AND ACCOUNTING METHODOLOGY

PROPOSED ADJUSTABLE COST RECOVERY (ACR) TARIFF

Q. WHAT CHANGES ARE INCLUDED IN THE PROPOSED ACR TARIFF?

A. Beginning with an effective date of January 1, 2012, the Company will use the ACR to maintain its revenues within the earnings band established by the Commission in this case. Beginning in 2011, the Company will make annual filings each November 1 based on the next year's budget, including the latest projections regarding rate base, revenues, expenses, changes in projected debt and preferred security costs, as well as the latest changes in laws and regulations that impact the revenue requirement, such as healthcare or income tax. If the Company's earnings projected for the upcoming year are within the ROE band established by the Commission in this docket, no adjustment under the ACR tariff will be requested. If the Company's earnings projected for the upcoming year are outside (either above or below) the approved ROE band, the ACR tariff will be used to adjust the Company's earnings back to the mid-point of the approved ROE band.

The ACR will also return to the sharing mechanism used prior to the 2007 Rate Case whereby one-third of any actual earnings above the band will be be retained by the Company as incentive to manage expenses and operate as efficiently as possible. The 2007 Rate Case Order provided that the one-third of any earnings above the upper end of the allowed ROE range would be used to offset any over or under earnings related to ECCR; however, that feature is no longer necessary under the Company's proposal because the proposed ECCR tariff will not be fixed for more than a one year period.

The ACR also provides for a "mirror image" which treats any actual earnings below the band the same as it treats earnings above the band. Under the ACR, if earnings are below

the bottom end of the earnings range, the Company will accept one-third of the shortfall and retail customers will be responsible for making up two-thirds of the shortfall.

Q. HOW WOULD EARNINGS ABOVE THE ROE RANGE BE SHARED WITH CUSTOMERS?

A. Earnings above the ROE range would be shared with customers on an actual, retroactive basis. Based on the latest calendar year earnings, as demonstrated in the most recent Annual Surveillance Report, the Company and the Commission would determine the amount of any refund due to customers. Once the magnitude of any refund was determined, the Company would recommend a period over which the refund would be made to customers. Likewise, if earnings were below the bottom of the allowed ROE range, the Company and the Commission would determine the magnitude of any shortfall; and the appropriate period over which two-thirds of it would be collected from customers.

Q. HOW WOULD THIS PLAN BENEFIT CUSTOMERS?

A. Customers would benefit in several ways. First, base rates would be reviewed, and adjusted if necessary, twice a year. Beginning in 2011, the Company's proposed base rates, as reflected in the annual November 1 filing, would be reviewed and approved by the Commission on a prospective basis with any change effective January 1 of the following year. In addition, base rates would be adjusted as necessary based on the Annual Surveillance Report for the previous year. The Annual Surveillance Report would be filed by March 15th (subject to release of the Company's Annual Report on Form 10-K) each year with any change effective by the following July 1.

Second, the financial stability and consistency of the Company would be maintained, thereby allowing the Company to retain its "A" credit rating and thereby keeping financing costs low and assuring access to the markets.

Third, by using this process and the tariffs included in the Alternate Rate Plan, the Company, the Commission and our customers would be better able to accommodate the many changes we anticipate and avoid large stair-step increases in favor of smaller, periodic adjustments. For example, if the economic recovery progresses faster than currently expected, customers would benefit from revised sales forecasts on an annual basis.

Fourth, customers benefit from cost controls and proactive management, as such actions are incentivized by the sharing mechanism in which two-thirds of excess earnings go to customers and one-third goes to the Company. Customers also benefit by the Company sharing in revenue shortfalls in a symmetrical manner. By limiting the Company's exposure to abnormally low returns, credit rating agencies, financial analysts and investors will be able to have confidence in the earnings expectations of the Company. Customers will benefit from the positive credit standing of the Company and the continued low financing costs and timely access to financial markets. Such access will allow the Company's construction programs to continue at advantageous financing without negatively impacting the reliability of the system.

Fifth, the Company's proposal provides a more meaningful forum for the Commission Staff and interested parties to review historic and projected costs. There will be more efficient reviews of historic results, and budgets will be limited to shorter periods of time. This process will be more transparent and easier to monitor than the current lengthy and complex filings we currently make in retail rate cases.

Finally, under the Company's plan, customers are protected from exposure to another full rate case. Under the Company's current plan, if earnings are projected to be below the approved ROE range, the Company may file a full rate case and thereby terminate the rate plan. The ACR eliminates the Company's ability to unilaterally terminate the rate plan early on that basis.

PROPOSED ENVIRONMENTAL COMPLIANCE COST RECOVERY (ECCR) TARIFF

Q. WHAT ARE THE TERMS OF THE CURRENT ECCR TARIFF?

A. In the 2007 Rate Case Order, the Commission ordered the establishment of the ECCR tariff. That tariff was designed to collect $222.3 million annually to cover the levelized costs of constructing, installing and operating environmental controls on several of the Company's coal-fired, generating plants from 2008 through 2010. However, as a result of the recession's impact on the Company's MWh sales, the current ECCR tariff rate is projected to collect only $214.7 million.

Q. PLEASE EXPLAIN THE PROJECTED DEFERRAL OF 2010 ENVIRONMENTAL COSTS IN ACCORDANCE WITH THE CURRENT ECCR TARIFF.

A. Under the terms of the ECCR tariff as approved in the 2007 Rate Case Order, the Company's actual construction and operating costs of specified environmental projects that exceeded the costs projected in the 2007 Rate Case were to be deferred for recovery in the 2010 rate case if the Company was earning below the mid-point of its allowed earnings range.

As addressed by the Commission in the 2009 Order, in 2010 the Company is projected to earn below the mid-point of the allowed earnings range. In addition, ECCR costs are currently projected to exceed the amounts reflected in the 2007 Rate Case, as shown on Exhibit___(APD/RBM-1, Schedule 2 ECCR), page 3 of 7. As a result, the Company currently projects that a total of $22.7 million of environmental capital and operating costs for 2010 will be deferred as a regulatory asset. The Company has proposed a three year amortization period to recover these costs.

Q. WHAT HAS BEEN DONE TO MINIMIZE THE ECCR REVENUE REQUIREMENT IN 2011?

A. As described previously, the Company is proposing to defer $78.2 million of depreciation and operating and maintenance ("O&M") expenses related to environmental projects in 2011 as a regulatory asset for one year to mitigate the impacts of the extended recession on the Company and its customers. Recovery of the regulatory asset would be amortized ratably over the three years beginning in January 2012. The amount deferred equates to the increase in depreciation and O&M expenses since the 2007 Rate Case.

In addition, by amortizing the 2010 deferred costs over three years, we have reduced the 2011 ECCR tariff by approximately $14 million.

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

A. The Company is requesting an increase of $115.1 million to be collected through the ECCR tariff in 2011. This amount reflects the following components:

- $99.7 million required to adjust the levelization of the 2008 through 2010 revenue requirements reflected in the 2007 Rate Case Order to the actual revenue requirements as of the end of 2010 ($222.3 million to $322.0 million); and

- $4.4 million required to reflect the impact of the recession on the ECCR tariff rate approved in the 2007 Rate Case Order net of an additional $3.2 million included in the deferred amount described below; and

- a net addition of $2 million to adjust for the increased environmental investment in 2011, after the proposed deferral of $78.2 million of depreciation and operation and maintenance expenses in 2011; and

- $9.0 million in amortization of the regulatory asset created in 2010 and the associated carrying costs.

These components are reflected in Exhibit___(APD/RBM-1, Schedule 2 ECCR) page 1 of 7, which also shows the projected investments and expenses associated with the ECCR tariff in 2012 and 2013. The 2011-2013 costs supporting these projections were previously filed with the Commission in the Company's 2010 IRP Proceeding as reflected in Supplemental Item S-49 of the MFRs filed in this proceeding.

Q. HOW IS THE COMPANY PROPOSING TO RECOVER FUTURE REVENUE REQUIREMENTS ASSOCIATED WITH THE ECCR TARIFF?

A. The Company will incorporate future environmental capital and operating costs into the ECCR tariff on an annual basis. Beginning in 2011, the Company will make an annual compliance ECCR tariff filing no later than November 1st. This compliance filing will reflect rates based on the costs for the next year, as previously approved by the Commission in this proceeding and as updated, if necessary, in future IRP updates. The Commission and its Staff will have 60 days to review, challenge and approve the proposed tariffs for the next year and the impact of the current revenue forecast. The approved rates will become effective January 1st of the following year. As a result of the stipulated agreement entered into by the Company and the Commission Staff on June 17, 2010 (the "2010 IRP and DSM Stipulation") to resolve the issues in the 2010 IRP and 2010 DSM Certification proceedings, we are requesting approval of the amounts shown on MFR Supplemental Item S-49. To support the terms of the ECCR tariff described above, in the future we request that the Commission approve the costs associated with government-mandated environmental controls in connection with the Company's subsequent IRP proceedings.

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

A. Consistent with the current ECCR tariff, the projected costs to be recovered through the ECCR tariff are set based on the projects approved in the IRP process. Changes in those cost projections will not impact the ECCR tariff rate unless they are approved by the Commission through an updated IRP filing. In this way, the Company bears the risk of making sure the projects are completed based on the budgeted amounts included in the latest approved IRP. The ECCR tariff would only change based on an updated revenue forecast, the cost of capital reflected in the Company's most recent Annual Surveillance Report, as approved by the Commission, and any subsequent updates to the latest IRP approved by the Commission.

One benefit of this approach is that customers would not bear the risk associated with changes from budget over an extended period, but rather would only pay for the costs and investments associated with the approved projections in the most recent IRP. Another benefit of this approach is that it includes projected revenue growth. By including projected revenue growth in the annual review of the ECCR tariff, customers will benefit because costs will be spread over the expected, expanded usage.

PROPOSED CERTIFIED CAPACITY COST RECOVERY (CCCR) TARIFF

Q. WHAT COSTS ARE TO BE RECOVERED THROUGH THE PROPOSED CCCR TARIFF?

A. For projects closing to service after January 1, 2011, the Company proposes to recover through the CCCR tariff the capital costs associated with new certified capacity such as McDonough Units 4, 5 and 6, and the capacity costs of certified Purchased Power Agreements, as well as any related transmission investments required. There are no CCCR tariff increases scheduled during 2011.

Q. HOW IS THE COMPANY PROPOSING TO RECOVER FUTURE REVENUE REQUIREMENTS ASSOCIATED WITH THE CCCR TARIFF?

A. The Company will file new rates using the CCCR tariff one month prior to the expected commercial operation of any new capacity with the new tariff becoming effective the month after commercial operation. Exhibit__(APD/RBM-1, Schedule 3 CCCR) page 1 of 5 shows the expected in-service dates and projected revenue requirements based on the 2010 IRP Proceeding, including McDonough Units 4, 5 and 6 as well as the planned biomass conversion of Plant Mitchell Unit 3.

The Commission has previously certified the generating capacity costs for Plants McDonough Units 4-6 and for the biomass conversion of Plant Mitchell Unit 3. In accordance with the 2010 IRP and DSM Stipulation, we are requesting approval of the costs for the transmission upgrades associated with Plant McDonough Units 4-6 and approved renewable project costs included in the MFRs, Supplemental Item S-48 filed in this proceeding. To support the terms of the CCCR tariff described above, in the future we request that the Commission approve the transmission costs associated with certified capacity and approved renewable projects in connection with the Company's subsequent IRP proceedings.

Q. WHAT BENEFITS DOES THE CCCR TARIFF PROVIDE?

A. The primary benefit of the CCCR tariff is that the uncertainty associated with the ultimate costs and in-service dates of these new certified capacity additions is removed and our customers are not impacted until the units are in-service and costs are known. As an example, based on the expected in-service date of McDonough Unit 4 of January 1, 2012, we will make its compliance filing under the CCCR tariff no later than December 1, 2011, thereby giving the Commission 60 days to review, analyze, and approve the new rates to be effective February 1, 2012.

This expedited process will be successful because the Commission has previously certified the costs associated with these capacity additions. In addition, the Commission has been monitoring actual construction costs related to self-build projects on an on-going basis. The calculation of the CCCR tariff will also be based on the cost of capital reflected in the Company's most recent Annual Surveillance Report, as approved by the Commission.

PROPOSED DEMAND SIDE MANAGEMENT (DSM) TARIFFS

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

A. The proposed DSM tariffs reflect the costs we expect will be certified in the Company's 2010 DSM Certification Proceeding. While the Commission will not vote on the 2010 IRP and DSM Stipulation until after this testimony is filed, we have reflected its terms in this filing, including the withdrawal of the Industrial DSM tariff and the phased-in schedule for recognizing additional sums of certified DSM programs. As a result, the Company is requesting an increase of $32 million to be recovered through the DSM tariffs, effective January 1, 2011.

Q. WHAT HAS BEEN DONE TO MINIMIZE THE DSM REVENUE REQUIREMENT IN 2011?

A. The Company worked closely with the Commission Staff to develop the 2010 IRP and DSM Stipulation and resolve the 2010 DSM Certification issues in a manner that also relieved 2011 rate impacts for customers. Examples include ramping up DSM program spending over a three year period and phasing in the additional sums such that no additional sum is recovered in 2011.

Q. HOW IS THE COMPANY PROPOSING TO RECOVER FUTURE REVENUE REQUIREMENTS ASSOCIATED WITH THE DSM TARIFF?

A. The Company is proposing to incorporate future program costs into the DSM tariff on an annual basis. Beginning in 2011, the Company would make an annual DSM tariff filing no later than November 1st. This compliance filing would reflect rates based on the costs for the next year, as previously approved by the Commission in the 2010 DSM Certification proceeding and as updated, if necessary, in future certification proceedings. The Commission and its Staff will have 60 days to review, challenge and approve the proposed tariffs for the next year and the impact of the current revenue forecast. The approved rates would become effective January 1st of the following year. The amounts shown on Exhibit___(APD/RBM-1, Schedule 4 DSM) reflect the costs agreed to in connection with the 2010 IRP and DSM Stipulation.

Q. WHAT HAPPENS TO THE DSM TARIFFS IF PROJECTED COSTS CHANGE?

A. Consistent with the current DSM tariff, the projected costs to be recovered through the DSM tariff are set based on the projects approved in the DSM Certification Proceeding. Changes in those cost projections will not impact the DSM tariff rate unless they are approved by the Commission through an updated certification proceeding. In this way, the Company bears the risk of making sure the projects are completed based on the amounts approved through the certification process. With the exception of a true-up related to participation levels, as specified in the 2010 IRP and DSM Stipulation, the DSM tariff would only change based on updated revenue forecasts and any subsequent certifications.

One benefit of this approach is that customers would not bear the risk associated with changes from budget over an extended period, but rather would only pay for the costs associated with the updated revenue forecasts and any subsequent certifications. Another benefit of this approach is that it includes projected revenue growth. By including

projected revenue growth in the annual review of the DSM tariff, customers will benefit because costs will be spread over the expected, expanded usage.

MUNICIPAL FRANCHISE FEE ("MFF") TARIFF

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

A. In the 2007 Rate Case Order, the Commission ordered the establishment of the MFF tariff in accordance with the Commission's Order in Docket No. 21112. The tariff was initially designed to collect $147 million, of which 25 percent of MFF revenues were to be collected from customers receiving service within a municipality's boundaries and 75 percent from all customers, regardless of location in 2008. This allocation was revised in 2009 to collect 50 percent of all MFF revenues from customers receiving service within a municipality's boundaries and 50 percent from all customers. The tariff is a percentage rate and is calculated based on each customers' total bill before sales taxes are applied. Thus, as revenues change the tariff does not have to be changed.

Q. IF THE MFF TARIFFS ARE PERCENTAGE RATES, WHAT COULD CAUSE THE MFF TARIFFS TO CHANGE?

A. There are two primary components of the MFF tariff that could change from year to year. First, if new municipalities served by Georgia Power are created, or older, established municipalities are unincorporated, the MFF tariff would need to change to accommodate the resulting change in the MFF revenues to be collected. Second, the amount of revenues collected relative to whether they are generated by customers receiving service within a municipality's boundaries or not would impact the relative tariffs for each respective group. As customer demographics change, so would the respective MFF tariff. Mr. Robert's testimony contains an additional explanation of the MFF tariff.

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

A. Yes. Since the 2007 Rate Case there has been a significant shift with a growing proportion of revenues coming from customers receiving service within municipal boundaries. In fact, there have been four municipalities incorporated since the 2007 Rate Case. They are the cities of Milton and Johns Creek in 2007 and Tyrone and Dunwoody in 2008. In addition, revenues from customers that receive service within municipal limits have increased from 55.7 percent in 2006 to over 58.2 percent in 2009. Likewise, revenues received from customers receiving service outside municipal limits decreased from 43.3 percent to 40.8 percent over the same time period.

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

A. The Company is proposing to update the proportionate share of revenues collected within municipalities into the MFF tariff in connection with the annual November 1 ACR compliance filing previously described. The approved rates will become effective January 1st of the following year. The Company is requesting approval of the $16.8 million increase shown on Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1) page 3 of 14 in connection with this proceeding, to be effective January 1, 2011.

CHANGE IN ACCOUNTING FOR REAL-TIME PRICING ("RTP") TARIFF COSTS

Q. HOW DOES THE COMPANY CURRENTLY CREDIT FUEL COSTS RELATED TO RTP USAGE?

A. The incremental portion of RTP is a base tariff that is a marginal rate. This marginal rate includes fuel costs. The Company allocates the RTP revenues between fuel and base components. Since the inception of the RTP rate, the Company has used the Fuel Cost

Recovery ("FCR") tariff, which changes after each fuel case, to determine the fuel component. The original goal of this accounting method was to ensure equal and average fuel cost accountability for both RTP and non-RTP customers. However, as fuel prices have become increasing volatile, under-recoveries have grown and their amortization become more extended, this method is no longer the best way to credit fuel accounts for the fuel used to serve RTP customers.

Q. WHY IS THE COMPANY PROPOSING CHANGES IN THE WAY THE COMPANY ACCOUNTS FOR RTP COSTS?

A. The Company has proposed this accounting change to better match fuel revenues and expenses attributable to RTP customers. As fuel prices have become increasingly volatile, under-recoveries have grown and the amortization period of such under-recoveries has become more extended, a modification to this method is needed to achieve this goal on a more timely basis. In recent years, highly volatile fuel prices have produced significant variations in RTP prices. The RTP hourly price can vary widely depending on replacement fuel costs while the FCR remains constant. These variations can create wide swings of amounts credited to the fuel and base accounts. By using a static number to allocate the fuel portion of RTP revenues, the current accounting no longer credits the proper amounts for fuel in the same period those costs are incurred.

Q. WHAT IS THE COMPANY'S PROPOSED MODIFICATION TO THE RTP ACCOUNTING?

A. Georgia Power is proposing to allocate RTP fuel based on the average marginal fuel costs (rather than the embedded FCR rate) on an hourly basis. This method will allocate more RTP revenue to fuel when fuel prices are increasing and less when they are decreasing, which mirrors the concepts behind the RTP rates. This will better match the recognition of fuel revenue with fuel costs attributable to RTP customers. As explained in the testimony of Mr. Roberts, the new accounting method will not affect the RTP prices paid

by customers, but rather will more appropriately allocate the revenues received from RTP customers between their fuel and base components.

Q. DOES YOUR EXPLANATION MEAN THAT THE FUEL ACCOUNTS HAVE NOT BEEN PROPERLY CREDITED FOR FUEL ATTRIBUTABLE TO RTP CUSTOMERS?

A. No. The proper amounts have been credited to fuel; however, the timing has fluctuated based on the implementation of new FCR rates. Under the proposed method, approximately the same amount will be contributed to the fuel account over the long term. However, the new method will more closely track fuel cost trends, thus reducing the lag.

Q. ISN'T THIS ADJUSTMENT IN RTP FUEL PRICING BETTER LEFT TO A FUEL CASE INSTEAD OF A BASE CASE?

A. No. While the cost of fuel related to RTP rates is charged to fuel accounts, it is the difference between RTP prices and fuel costs that impacts base rates. Therefore, the issue of the appropriate fuel costs to charge to fuel accounts relative to RTP prices has a direct impact on base rates and base revenue requirements, which is why we've addressed it here.

Q. WHAT IS THE EXPECTED RESULT OF THIS PROPOSED CHANGE ON BASE REVENUE REQUIREMENTS?

A. We have reduced the requested base revenue requirements for calendar year 2011 by $45 million as a result of the proposed RTP accounting change to match fuel prices and fuel costs associated with the RTP tariff on a more timely basis.

If the Commission does not approve the proposed change in RTP accounting the revenue requirements to be collected through the traditional base tariffs would need to be increased by this amount.

III. REVENUE REQUIREMENT

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

A. The historical data in this filing is based on the Company's actual performance for the twelve months ended December 31, 2009. The projected test period for the traditional, single-increase revenue requirement is the calendar year ending December 31, 2011. In addition, to meet the requirements of the 2007 Rate Case Order, we have also provided a projected test period ending July 31, 2011. This filing also includes projections to support annual revenue requirements in 2012 and 2013. Based on the costs projected to be recovered through the ECCR, CCCR, DSM and MFF tariffs as previously described, any adjustments related to costs proposed to be recovered through the ACR tariff will be dependent on whether the Company's projected earnings fall within the allowed range of ROE approved by the Commission in this docket.

Q. WHY IS THE COMPANY CHOOSING TO BASE THE REVENUE REQUIREMENT ON A TEST PERIOD ENDING DECEMBER 31, 2011 INSTEAD OF THE JULY 31, 2011 TEST PERIOD AS ORDERED BY THE COMMISSION IN THE 2007 RATE CASE ORDER?

A. There are two reasons the Company has chosen to present the requested revenue requirement based on a test period ending December 31, 2011 rather than July 31, 2011. First, the test period ending July 31, 2011 only partially recognizes the increase in rate base and expenses that the Company will incur in the first full year following an approved increase in rates. By presenting the revenue requirement for the entire period ending December 31, 2011, the Company is demonstrating the true revenue increase required to at least have an opportunity to earn the allowed rate of return during all of 2011. Second, by reflecting the base revenue requirement for the twelve months ending December 31, 2011, the revenue requirement is synchronized with the other proposed

changes to the Company's existing DSM and ECCR tariffs, which are based on calendar year projections.

We have also provided the revenue requirement increase for the test period ending July 31, 2011, which is $809 million, (including increases to be recovered under the Company's traditional base tariffs, as well as the ECCR, DSM and MFF tariffs) as shown in Exhibit___(APD/RBM-3). However, we believe that the calendar year is more appropriate.

Q. PLEASE SUMMARIZE THE RESULT OF YOUR REVENUE REQUIREMENT CALCULATIONS.

A. The revenue requirement calculation shows a revenue deficiency of $451 million for the period ending December 31, 2011 to be collected through the traditional base tariffs. The jurisdictional allocations are based on an allocated cost-of-service study for the projected test period ending July 31, 2011 that Mr. Michael O'Sheasy will discuss in his testimony. Dr. James H. Vander Weide will discuss the Company's required ROE.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE RETAIL REVENUE DEFICIENCY AMOUNT.

A. The revenue deficiency of $451 million is shown in Exhibit___(APD/RBM-, Schedule 1, Workpaper 1) page 1 of 14. Revenue collected from customers must cover all costs of service, including operation and maintenance expenses, taxes, depreciation, and the cost of capital, including an appropriate ROE. The Company must satisfy the interest and dividend requirements of its debt and preferred stock, and provide a fair return on common stock. These cost of capital requirements are weighted by the mix of debt, preferred securities, preferred stock, preference stock and common equity, adjusted to reflect certain Commission rate making policies, to produce an overall required retail rate

of return. This return is then applied to the retail rate base to yield the Company's retail earnings requirement.

The retail earnings requirement is then compared to earnings projected under the Company's current rates to determine the amount of revenue deficiency during the test period. This earnings deficiency is then adjusted to cover several items (the largest of which is income taxes) by using an "income expansion factor." This factor, 61.049 percent, reflects a Federal income tax rate of 35 percent and a State income tax rate of 6 percent. The income expansion factor also provides for uncollectible accounts and sales tax collection fees. The retail earnings deficiency is then divided by the income expansion factor to determine the total revenue deficiency from retail customers.

The computation of the income expansion factor is shown in Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1) page 2 of 14.

Q. WHAT IS THE SOURCE OF THE PROJECTED AMOUNTS USED IN THE RATE FILING?

A. The projected amounts used to calculate the revenue deficiency and rate base come from the Company's 2010 Annual Budget. The preparation of the Company's annual budget is a cyclical process of planning, resource identification, review, revision and approval. The process involves all functional areas throughout the Company. The end result of the process is a comprehensive financial budget, covering a period of five calendar years, which reflects our best estimate of the resources required to maintain the level of service our customers expect, while effectively managing costs.

Q. WHAT IS THE RETAIL RATE BASE UPON WHICH THE COMPANY IS BASING ITS REVENUE DEFICIENCY?

A. Retail rate base is $12.69 billion for the period ending December 31, 2011 as shown in the revenue deficiency calculation in Exhibit___(APD/RBM-, Schedule 1, Workpaper 1) page 1 of 14, line 1.

Q. WHAT RATE OF RETURN IS APPLIED TO THE RETAIL RATE BASE IN THE REVENUE REQUIREMENT CALCULATION?

A. The Company's overall adjusted retail cost of capital is 8.76 percent for the period ending December 31, 2011, as developed in Exhibit___(APD/RBM-1, Schedule 5, Workpaper 1).

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

A. The Company's overall cost of capital of 8.76 percent is based on the average of the estimated capitalization from December 31, 2010 through December 31, 2011. The long-term debt, preferred securities and preferred and preference stock proportions of capitalization, adjusted to reflect certain Commission-approved rate making policies, are multiplied by the average of their estimated embedded costs from December 31, 2010 through December 31, 2011. The required return on common equity of 11.95 percent is described by Dr. Vander Weide in his testimony.

The average embedded cost of long-term debt as of December 31, 2011 is 5.38 percent. The average embedded cost of preferred securities as of December 31, 2011 is 8.32 percent. The average embedded cost of preferred stock as of December 31, 2011 is 6.13 percent. The average embedded cost of preference stock as of December 31, 2011 is 7.13 percent. Workpapers 2 and 3 of Exhibit___(APD/RBM-1, Schedule 5) show the capital structure components for the test year, together with associated costs.

Q. HOW HAS THE COMPANY PRESENTED THE REVENUE REQUIREMENT CALCULATIONS FOR THE OTHER PERIODS SPECIFIED IN THE 2007 RATE CASE ORDER?

A. While the exhibits attached to our testimony focus on the requested test period ending December 31, 2011, as required in the Commission's 2007 Rate Case Order, the information and calculations pertaining to the test period ending July 31, 2011 are contained in the MFRs. In addition, we have included many of the same exhibits that were not strictly required under the MFR rules as Supplemental items in the MFRs. Please refer to the Table of Contents of the MFRs filed in this docket.

The Company has also filed revenue requirement information for the calendar years 2012 and 2013, as required in the 2007 Rate Case Order. This information is not intended to represent the Company's revenue requirement requests for those periods. As explained previously, any adjustment to base tariffs in periods beyond 2011 will be calculated in accordance with the terms of the proposed ACR tariff and as a result of actual earnings compared to the earnings range as presented in Annual Surveillance Reports. The 2012 and 2013 revenue requirements presented are only examples based on the 2010 budget and will be updated annually. The 2012 and 2013 revenue requirements for costs to be recovered through the ECCR, CCCR and DSM tariffs are shown separately in Exhibits___(APD/RBM-1) Schedules 2 and 3 , respectively.

SUMMARY OF PROJECTIONS

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

A. The Company has made the following adjustments as reflected in Exhibit___(APD/RBM-3, Schedule 4):

1. Treated the corporate headquarters building lease as an operating lease instead of a capitalized lease, basically allowing recovery of only the lease payments through retail rates.
2. Treated the Rome headquarters lease as an operating lease instead of a capitalized lease, basically allowing recovery of only the lease payments through retail rates.
3. Removed institutional and goodwill advertising from retail expenses.
4. Credited retail customers with 75 percent of the profits related to Economy Energy/Opportunity sales.
5. Credited retail customers with 80 percent of the profits related to short-term capacity sales.
6. Removed expenses related to the Nuclear Energy Institute from retail.
7. Removed Southern Company Generation and Energy Marketing expenses from retail.
8. Increased purchased power expenses for the additional sums the Company is allowed to collect on certain of these agreements
9. Reduced retail revenues by the amount of the carrying cost on the fuel cost recovery under-recovered balance since these costs are recovered through the Fuel Cost Recovery rate.
10. Excluded unregulated outdoor lighting revenues, expenses, and net plant-in-service costs from retail.
11. Reflected the adjustment required by Internal Revenue Code Section 167L.
12. Removed the revenues and expenses related to Municipal Franchise Fees.
13. Decreased Federal Income Tax expense to reflect the treatment of the Internal Revenue Code Section 199 Manufacturer's Tax Deduction, as stipulated to in the 2007 Rate Case.
14. Removed revenues and expenses related to the licensing of boundary lands regulated by the Federal Energy Regulatory Commission ("FERC").
15. Removed Accumulated Deferred Income Taxes (ADITs) related to CWIP.

16. The interest synchronization adjustment reflects the tax impact of the previous changes as a result of the interest costs related to the retail rate base.
17. Reduced the external nuclear decommissioning asset retirement obligation balances by the amount of the nuclear decommissioning funds held by the external trustee, thereby more closely matching the assets held for nuclear decommissioning against the liability represented by the asset retirement obligation.
18. Reflected the cumulative impact of these adjustments on cash working capital.

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

Q. WHAT OTHER ADJUSTMENTS ARE INCLUDED RELATED TO THE NEW TARIFFS PROPOSED BY THE COMPANY?

A. To accommodate the new tariffs related to DSM, ECCR and CCCR, we have made the following adjustments in the test period revenue requirements to be collected through the traditional base rate tariffs:

1. Excluded the budgeted costs of currently approved DSM programs that will be collected in the proposed DSM tariff.
2. Decreased Customer Assistance expenses by $11.9 million to remove budgeted amounts for proposed DSM programs that will be collected through the DSM tariffs.
3. Removed the impact of the current ECCR tariff and included current and projected environmental investments and expenses.
4. Removed the levelized balance of ECCR revenues that was accrued in accordance with the 2007 Rate Case Order.
5. Removed CWIP related to Plant Vogtle Units 3 and 4 in accordance with the Commission's order in Docket No. 27800 and the Georgia Nuclear Energy Financing Act. The related financing costs will be collected through the Nuclear

Construction Cost Recovery tariff that becomes effective January 1, 2011. Mr. Roberts will discuss the NCCR tariff further in his testimony.

Q. WHAT ADDITIONAL ADJUSTMENTS ARE INCLUDED IN THE COMPANY'S FILING?

A. The Company is proposing the following adjustments:

1. Increase depreciation expense by approximately $22.6 million to reflect new depreciation rates.
2. Decrease expenses by $87 million for the proposed deferral of the increase in depreciation expense during the test period since the 2007 Rate Case to offset the temporary lag in revenues as a result of the extended economic recession.
3. Decrease funding for nuclear decommissioning by $1.8 million.
4. Reflect the recently approved delay in the in-service dates of combined cycle combustion turbines at Plant McDonough Units 4, 5 and 6, which decreases 2011 revenue requirements by $87 million.
5. Reflect the recently approved extended operation of the coal-fired steam generating units at Plant McDonough Units 1 and 2.
6. Increase rate base and expenses for the inclusion of the transmission investment necessary to connect Plant McDonough Units 4, 5 and 6.
7. Include the $77 million unamortized portion of other Costs of Removal from 2009, plus additional other Costs of Removal amounts not previously included under the Commission's order in Docket No. 30039; and the amortization of the combined regulatory liabilities over 36 months (2011 through 2013).
8. Reflect the impact of the recently enacted Patient Protection and Affordable Care Act and the Health Care and Education Affordability Reconciliation Act of 2010.
9. Include the full twelve month impact of storm damage and environmental remediation reserves.

10. Decrease Other Operating Revenues by $118,000 in order to provide retail customers with credit for one-half the projected revenues related to location of wireless communication devices on the Company's transmission towers.
11. Increase Administrative and General expense by $600,000 in order to fund expert witnesses and consultants appearing for the Commission in this docket, in accordance with recently enacted state legislation.

Q. PLEASE EXPLAIN THE IMPACT OF THE NEW DEPRECIATION RATES BEING PROPOSED BY THE COMPANY.

A. Depreciation rates are reviewed periodically to ensure that they continue to reflect the current cost of providing service. Our latest depreciation study shows that current depreciation rates, which were established in 2007, need to be changed to reflect updated estimates of service life and removal costs and to recognize the additional investment in new facilities and retirements since 2006. Based on the new study, the net increase in depreciation expense is approximately $19.1 million annually (measured as of December 31, 2008), after including the impacts of the delay in the McDonough units and the amortization of certain dismantlement costs described below. Please refer to Exhibit___(APD/RBM-2, Schedule 7, Workpaper 3) and the depreciation study, which can be found in Appendix__ Exhibit 3 of this filing.

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

A. The depreciation study was updated by American Appraisal Associates. In addition, SCS updated the Dismantling Study through 2008 on which American Appraisals relied for certain assumptions in their study. The study was prepared using the same methodology approved by the Commission in the 2007 Rate Case. The key principles reflected in the rates are the average life group procedure, the remaining life technique and the salvage and cost of removal approach generally utilized by Commission Staff witness, Mr. King,

in Docket No. 4007. The current study is consistent with the principles and processes followed in the 2007 Rate Case.

Q. WHY IS THE COMPANY DECREASING DEPRECIATION EXPENSE BY EXTENDING THE LIFE OF CERTAIN GENERATING UNITS?

A. For accounting purposes, the Company has extended the lives of generating units to 65 years that have received environmental controls to bring those units into full compliance with current regulations.

Q. WHY IS THE COMPANY INCREASING DEPRECIATION EXPENSE BY DECREASING THE LIFE OF OTHER GENERATING UNITS?

A. According to the latest economic evaluation of certain coal-fired generating plants filed in Docket No. 31081, and based on the Company's best estimates for meeting certain environmental control rules, as contained in the Georgia Multi-Pollutant Rule promulgated by the Environmental Protection Division of the Georgia Department of Natural Resources, several generating units will need to be retired at the end of 2014, earlier than projected in previous depreciation studies. Therefore, the Company has reflected this adjustment in the proposed depreciation rates, including a four-year amortization period for the related dismantlement costs.

Q. WHY HAS THE COMPANY ADJUSTED EXPENSES DURING THE TEST PERIOD?

A. As described previously, the Company is requesting that the Commission approve the deferral of $87 million of depreciation expense as a regulatory asset for one year to mitigate the impacts of the extended recession on the Company and its customers. Recovery of the regulatory asset would be amortized ratably over three years beginning in January 2012. The amount deferred equates to the increase in depreciation expense

related to investments that have been added since the 2007 Rate Case, as adjusted for the new rates contained in the depreciation study.

Q. PLEASE EXPLAIN THE UPDATE TO FUNDING FOR NUCLEAR DECOMMISSIONING.

A. The Company has adjusted the budgeted funding of the nuclear decommissioning trust account to reflect the treatment stipulated to in Docket Nos. 14000, 18300 and 25060. This adjustment incorporates the use of the Nuclear Regulatory Commission (NRC) Option 2 guidelines for removal and disposal of radiated structures as opposed to the results from an updated site-specific nuclear decommissioning study from TLG Services, Inc. In addition, external trust fund balances, as of December 31, 2009, were used to calculate the projected fund contributions until decommissioning. The adjustment also reflects the 20 year license extension of Vogtle units 1 and 2, which was received from the NRC in June 2009. Consistent with the Commission's previous orders, the Company also reduced the level of requested annual funding by $1.8 million, as a result of removing site restoration costs associated with returning the site to "greenfield" status.

Accordingly, we have decreased annual nuclear decommissioning expense from $3,462,000 to $1,686,000 in this filing. The proposed level of nuclear decommissioning funding will provide for the estimated cost of decommissioning structures, equipment and the storage and eventual removal of spent nuclear fuel. The requested amount will also meet minimum funding requirements of the NRC. As required by the Commission, the amounts collected will continue to be placed in an external fund. Information supporting the funding requirement calculation can be found in Exhibit___(APD/RBM-2, Schedule 7, Workpaper 4) of the Test Period Revenue Requirement portion of this filing.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO REFLECT THE EXTENDED CONSTRUCTION SCHEDULE AND RELATED COMMERCIAL OPERATION DATES FOR PLANT MCDONOUGH UNITS 4, 5 AND 6.

A. In Docket No. 24506, the Commission approved the extension of the construction schedule and the related commercial operation dates of the certified capacity provided by Plant McDonough Units 4, 5 and 6 (eleven months for Units 4 and 5, and seven months for Unit 6). As a result, the investment and expenses included in the budget need to be adjusted to reflect the latest assumptions and the Commission's order. The adjustment reduces projected operating and maintenance expenses, decreases depreciation expenses, increases purchased power expenses and impacts taxes as well. In addition, projected investment in the test period is reduced while accumulated depreciation is decreased and accumulated deferred income taxes are adjusted accordingly.

Since the commercial operation dates of the combined-cycle combustion turbines at Plant McDonough Units 4, 5 and 6 have been delayed, in order to maintain the integrity of the transmission system, we have extended the service lives of the coal-fired steam generation plants at Plant McDonough Units 1 and 2 past their originally projected retirement dates. This adjustment also reflects the additional costs associated with the extension of service.

In addition, this adjustment reflects an increase in rate base and expenses associated with the transmission investment necessary to connect Units 4, 5 and 6 to the transmission grid. While the in-service dates of generating units have been delayed, the transmission interconnection will be completed slightly ahead of schedule in late 2010. This adjustment is necessary to ensure appropriate recovery of these transmission costs.

Q. WHAT IS THE COMPANY PROPOSING WITH REGARD TO OTHER COSTS OF REMOVAL?

A. The Company did not require all the amortization originally approved in the 2009 Order to meet the revised allowed ROE, thus there was a remaining balance of $65.7 million. The Company has also identified $26.8 million of additional other Cost of Removal that can be returned to customers. Therefore, this adjustment amortizes the total $92.5 million over a 36-month period beginning January 2011.

Q. WHY HAS THE COMPANY REFLECTED THE IMPACT OF NEW HEALTHCARE LEGISLATION IN RETAIL RATES?

A. The Patient Protection and Affordable Care Act ("PPACA") and the Health Care and Education Affordability Reconciliation Act of 2010 (the "Health Care Acts") were signed into law in March, 2010. These laws require the Company to make certain accounting changes upon adoption. Specifically, a federal subsidy for retiree drug costs was previously non-taxable. Effective in 2013, with adoption of PPACA, these subsidies become taxable to the Company. Under the rules for Accounting for Income Taxes, formerly under FAS 109 (now known as Accounting Standards Codification 740), the change in taxability is considered a change in tax rates that is required to be recognized in the period the change becomes law. The Company has recorded a regulatory asset to be amortized over a 12-year period representing the remaining average service life of plan participants.

Q. WHAT IS THE $118,000 ADJUSTMENT RELATED TO WIRELESS CO-LOCATION REVENUES?

A. In Docket No. 25322, the Commission ordered that retail customers receive credit for one-half of the revenues the Company receives in return for allowing wireless telecommunication companies to locate their equipment on the Company's transmission

towers. Since all the projected revenues are included in Other Operating Revenues, this adjustment removes one-half of the co-location revenues and thereby gives credit to retail customers for one-half of those revenues.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO INCREASE ADMINISTRATIVE AND GENERAL EXPENSES BY $600,000 FOR COMMISSION CONSULTING COSTS.

A. In the 2010 Georgia General Assembly, House Bill 1233 was passed and signed into law May 20, 2010. The law requires companies regulated by the Georgia Public Service Commission to pay up to $600,000 of fees incurred by the Commission for consultants and expert witnesses during a major base rate case such as this one. The adjustment reflects this additional cost to our retail customers.

ADJUSTMENTS RELATED TO PROPOSED TARIFFS

Q, PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE DSM PROGRAM EXPENSES FROM THE TEST PERIOD?

A. In the Company's 2010 DSM Certification Proceeding, the Company and Staff have discussed modifying and developing new DSM programs, and cost recovery by separate DSM tariffs. Since those costs are expected to be recovered by the new DSM tariffs and to avoid recovering these costs twice, we have removed budgeted DSM costs from the test period revenue requirement calculation in anticipation that the Commission will order such treatment for DSM costs.

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR THE ECCR TARIFF?

A. This adjustment removes any revenue impact associated with the ECCR tariff ordered in the 2007 Rate Case. The adjustment also removes the projected environmental investments and expenses to be recovered through the ECCR tariff.

Exhibit___(APD/RBM-1, Schedule 2 ECCR) summarizes the levelized costs for 2008-2010 as approved in the 2007 base rate case, as well as the projected 2011-2013 projected costs.

WHOLESALE SALES

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

A. There are three types of wholesale sales. The first is Economy Energy/Opportunity sales, the second is Market-Based Tariff sales from non-specified generating units, and the third is Wholesale Block Power sales. The Company's final Unit Power Sales contract expired in May 2010.

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

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

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

A. These are sales of capacity and energy made from Company resources to off-system companies under the Southern Company FERC-approved, market-based tariff. Consistent with the treatment of these sales in Georgia Power's 1983 rate case in Docket No. 3397 and subsequent dockets, we have allocated 80 percent of capacity revenues from these sales to the Company's retail customers.

Q. PLEASE DESCRIBE THE TREATMENT OF BLOCK POWER SALES.

A. The Wholesale Block Power Sales are contractual agreements between Georgia Power and non-associated companies that provide for capacity and energy sales of approximately 1,309 MW which were priced from a list of specific Georgia Power fossil-steam and combustion turbine units (i.e., blocks). Investment and expenses associated with these blocks have been assigned to wholesale based on Block Power megawatt sales as a percentage of the Company's share of the assigned units. Exhibit___(APDRBM-2, Schedule 7, Workpaper 7) reflects these Wholesale Block Power Sales assignments and allocations.

Consistent with their treatment in previous rate cases, the investment, revenues and expenses related to Georgia Power blocks which are sold off-system have been assigned to wholesale service and are thus not included in retail cost of service.

TAXES

Q. WHAT TAXES DOES THE COMPANY PAY?

A. The Company pays Federal and State income taxes, local property taxes, sales and use taxes, social security and unemployment taxes and several other miscellaneous types of taxes. Taxes other than income taxes are shown on Exhibit___(APD/RBM-2, Schedule 5) and the computation of income taxes is shown on MFR Supplemental item S-47.

Q. FOR WHAT ITEMS HAVE YOU PROVIDED DEFERRED INCOME TAXES?

A. MFR Supplemental item S-47 identifies the categories of timing differences for which we have provided deferred income taxes. It also shows both the provision for deferred income taxes and the reversal of income taxes deferred in prior years for each specific item.

WORKING CAPITAL

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

A. Working capital for a regulated utility can be described as the average amount of capital (in excess of that used to finance net utility plant and other separately identified rate base components) necessary to operate the business. This capital bridges the gap from when costs are incurred to provide electric service to when the Company is actually paid for that service. It also covers those items that must be financed by investors pending recovery from customers. This is different from the definition of working capital as it is used in the ordinary business or accounting sense. Working capital as applied to commercial enterprises is defined as current assets less current liabilities and is used for purposes of evaluating the liquidity of a commercial business at a given point in time.

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

A. The working capital requirement included in this filing consists of thirteen-month average balances of materials and supplies inventories, minimum bank balances, petty cash (working funds) and prepayments. Additionally, a provision for cash working capital (i.e., cash necessary to pay operating expenses prior to collection of revenues) is included in overall working capital.

Q. HAVE THE RESULTS OF YOUR WORKING CAPITAL STUDY BEEN SUMMARIZED?

A. Yes. Exhibit___(APD/RBM-2, Schedule 4, Workpaper 4) page 4 of 4 shows the Company's total estimated pro forma cash working capital requirement for the test year. In addition, Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1) page 3 of 14 reflects the

estimated cash working capital related to municipal franchise fees. The estimated cash working capital for the period ending December 31, 2011 including municipal franchise fees is $200,844,000. The remaining components, as shown on Exhibit___(APD/RBM-2, Schedule 4, Workpaper 1), are average materials and supplies inventories of $883,152,000, average prepayments of $74,830,000 and average minimum bank balance requirements of $15,000,000.

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

A. We performed a lead-lag study to determine the Company's estimated cash working capital requirement for the test period. The study approach used is consistent with prior studies approved by this Commission. The lead-lag approach involves a study of the time lag between the date customers receive service from the Company and the date they pay for such service. This is reduced by any offsetting time lead between the date that suppliers and employees render service to the Company and the date the Company pays for such services. Consistent with the Commission's orders in previous dockets, the time leads from investor-supplied funds are also included in the study.

The lead-lag approach is generally accepted as the most reliable method for determining a cash working capital requirement and the stated preference of this Commission. One of the most important aspects of the lead-lag method is that it provides specific analysis of day-to-day operations of the Company, and the results are applied to specific Company accounts (i.e., total cost of service). The lead-lag method does not rely on point-in-time balances from historical accounting records; rather, it provides a picture of the average flow of funds a utility requires in its operating cycle. Although this approach is much more time-consuming than some other methods, it produces a more refined analysis. A complete description of the lead-lag study is included in Appendix__ Exhibit 4.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

GEORGIA POWER COMPANY
Docket No. 31958
Filing Pursuant to Docket No. 25060

Ms. Daiss and Mr. Morris -- Summary of Filing

Exhibits Index

Exhibits	Description
APD/RBM-1 Exhibits	
Exhibit____(APD/RBM-1, Schedule 1, Workpaper 1)	Computation of Retail Revenue Deficiency (2011)
Exhibit____(APD/RBM-1, Schedule 1, Workpaper 2)	Computation of Retail Revenue Deficiency (2012)
Exhibit____(APD/RBM-1, Schedule 1, Workpaper 3)	Computation of Retail Revenue Deficiency (2013)
Exhibit____(APD/RBM-1, Schedule 2 ECCR)	ECCR (2011 - 2013)
Exhibit____(APD/RBM-1, Schedule 3 CCCR)	CCCR (2012 - 2013)
Exhibit____(APD/RBM-1, Schedule 4 DSM)	DSM (2011 - 2013)
Exhibit____(APD/RBM-1, Schedule 5, Workpaper 1)	Adjusted Retail Rate of Return Summary
Exhibit____(APD/RBM-1, Schedule 5, Workpaper 2)	Capital Structure - Forecast
Exhibit____(APD/RBM-1, Schedule 5, Workpaper 3)	Cost of Debt, Pref. Securities & Pref. Stock
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 1)	Adjusted Retail Rate of Return Summary
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 2)	Calculation of Retail Capital Components
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 3)	Cost of Long-Term Debt
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 4)	Cost of Long-Term Debt
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 5)	Reacquired Debt
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 6)	Cost of Long-Term Debt
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 7)	Reacquired Debt
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 8)	Cost of Preferred Securities
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 9)	Reacquired Debt
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 10)	Cost of Preferred Stock
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 11)	Cost of Preference Stock
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 12)	Common Stock Capital
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 13)	Common Stock Capital
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 14)	Retail Capital Structure
Exhibit____(APD/RBM-1, Schedule 6, Workpaper 15)	Retail Capital Structure
APD/RBM-2 Exhibits	
Exhibit____(APD/RBM-2, Schedule 1)	Electric Plant-In-Service
Exhibit____(APD/RBM-2, Schedule 2)	Accumulated Provision for Depreciation & Amortization
Exhibit____(APD/RBM-2, Schedule 3)	Other Rate Base Items
Exhibit____(APD/RBM-2, Schedule 4, Workpaper 1)	Working Capital
Exhibit____(APD/RBM-2, Schedule 4, Workpaper 2)	Working Capital - Materials & Supplies
Exhibit____(APD/RBM-2, Schedule 4, Workpaper 3)	Working Capital - MBB, Prepayments & Petty Cash
Exhibit____(APD/RBM-2, Schedule 4, Workpaper 4)	Cash Working Capital
Exhibit____(APD/RBM-2, Schedule 5)	Taxes Other than Income Taxes
Exhibit____(APD/RBM-2, Schedule 6, Workpaper 1)	Non-Deductible Book Depreciation
Exhibit____(APD/RBM-2, Schedule 6, Workpaper 2)	Summary of Accumulated Deferred ITC
Exhibit____(APD/RBM-2, Schedule 6, Workpaper 3)	Summary of Accumulated Deferred Taxes
Exhibit____(APD/RBM-2, Schedule 7, Workpaper 1)	Interest Synchronization
Exhibit____(APD/RBM-2, Schedule 7, Workpaper 2)	Unregulated Outdoor Lighting
Exhibit____(APD/RBM-2, Schedule 7, Workpaper 3)	Estimated Impact of New Depreciation Rates
Exhibit____(APD/RBM-2, Schedule 7, Workpaper 4)	Nuclear Decommissioning Expense
Exhibit____(APD/RBM-2, Schedule 7, Workpaper 5)	Storm Damage Reserve
Exhibit____(APD/RBM-2, Schedule 7, Workpaper 6)	Adjusted Cash Working Capital
Exhibit____(APD/RBM-2, Schedule 7, Workpaper 7)	All Wholesale
ADP/RBM-3 Exhibits	
Exhibit____(APD/RBM-3, Schedule 1, Workpaper 1)	Computation of Retail Revenue Deficiency (Test Period)
Exhibit____(APD/RBM-3, Schedule 2 ECCR)	ECCR (Test Period)
Exhibit____(APD/RBM-3, Schedule 3 DSM)	DSM (Test Period)
Exhibit____(APD/RBM-3, Schedule 4)	Summary of Projections

GEORGIA POWER COMPANY

COMPUTATION OF THE TEST PERIOD RETAIL REVENUE DEFICIENCY
ESTIMATED FOR THE TWELVE MONTHS ENDING JULY 31, 2011
(Amounts in Thousands)

LINE NO. (1)	DESCRIPTION (2)	TOTAL REVENUE DEFICIENCY (3)	
1	Retail Rate	$ 14425450	(a)
2	Requested	x 0.0871	(b)
3	Earnings	$ 1256457	
4	Deduct: Earnings Avai	794855	(a)
5	Earnings D	$ 461601.7	
6	Income Ex	÷ 0.61059	(c)
7	Revenue Deficiency Excluding Municipal Franchise Fees (MFF	$ 755992.9	
8	Less: ECC	- 181317	(d)
9	Traditional	$ 574675.9	

(a) From Exhibit____(MTO-1)
(b) From M.F.R Item D-1(e) Page 2 of 2
(c) From Exhibit____(APD/RBM-3, Schedule 1) page 2 of 3
(d) From Exhibit____(APD/RBM-3, Schedule 2 ECCR) page 1 of 4

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

COMPUTATION OF THE CALENDAR YEAR RETAIL REVENUE DEFICIENCY
APPLICABLE TO TRADITIONAL BASE RATE TARIFFS
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO. (1)	DESCRIPTION (2)		TOTAL REVENUE DEFICIENCY (3)	
1	Retail Rate	$	12688403	(a)
2	Requested	x	0.0876	(b)
3	Earnings	$	1111504	
4	Deduct: Earnings Avai		835890.5	(c)
5	Earnings D	$	275613.6	
6	Income Ex	÷	0.610492	(d)
7	Revenue Deficiency Applicable to Traditional Base			
8	Rate T	$	451461.5	

(a) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 1) page 5 of 14
(b) From Exhibit____(APD/RBM-1, Schedule 5, Workpaper 1)
(c) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 1) page 4 of 14
(d) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 1) page 2 of 14

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

DERIVATION OF INCOME EXPANSION FACTOR
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

1	Additional Revenue					1
2	Less:					
	Federal and State Income Taxes					-0.38679
	Net After Income Taxes					0.61321
3	Less:					
	Uncollectible Accounts					
	Estimated Calendar Year Uncollectible Accounts Expense /	$	33655	=	0.004783	
	Estimated Calendar Year Retail Revenues (Excl Street & Hwy Li	$	7037019			
	Reduction in Income Taxes = 0.478% x 38.679%				-0.00185	
	Net Effect of Uncollectible Accounts					-0.00293
	Net After Income Taxes and Uncollectible Accounts					0.610277
4	Add:					
	Additional Compensation for Collecting State Sales Tax					
	Estimated Calendar Year Sales Tax on Revenue /	$	494915	=	0.069625	
	Estimated Calendar Year Retail Revenues	$	7108295			
	Collection Fee = 0.5%					
	Compensation Percentage = 6.962% x 0.5%				0.00035	
	Increase in Income Taxes = 0.035% x 38.679%				-0.00014	
	Net Effect of Additional Compensation					0.000215

5	After Tax Effect of Additional Revenue	0.610492

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

COMPUTATION OF THE IMPACT OF MUNICIPAL FRANCHISE FEES (MFF)
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

Line No.	Description		Amounts	
-1	-2		-3	
1	Total Budgeted Revenue Before MFF:	(a)	7325423	
2	% of Revenues Inside Municipalities	(b)	0.58	
3	Portion Inside the Municipalities:		4248745	
4	MFF Rate		0.04	
5	MFF Expenses			169949.8
6	MFF Expense Lead Days		-236.25	
7	Revenue Lag Days (c)		38.1	
8	Net Lead Days		-198.15	
9	Calendar Year Days		365	
10	Average MFF Working Capital		-92262	
11	Pre-Tax Weighted Average Cost of Capital (d)		0.1272	
12	Carrying Charge on Pro Forma Average MFF Working Capital			-11736
13	Adjusted Calendar Year - MFF Expenses			158213.8
14	Franchise Fees included in Current Rates			-154295
15	Additional MFF revenue requirement on existing rates			3918.428
16	MFF rate to be used on incremental revenue requirements			
17	(158,214 / 7,325,423)		0.021598	
18	Incremental MFF revenue requirement on Traditional Base Rate Tariffs =			
19	$451,462 (e) x 2.16%			9750.625
20	Incremental MFF revenue requirement on ECCR = $115,144 (f) x 2.16%			2486.875
21	Incremental MFF revenue requirement on DSM = $31,654 (g) x 2.16%			683.6499
22	Total MFF Revenue Deficiency			16839.58

(a) From 2011 Forecasted Retail Revenues Less: 2011 Projected MFF
(b) From 2009 Percent of Revenues Located within Municipalities
(c) From Exhibit___(APD/RBM-2, Schedule 4, Workpaper 4) page 4 of 4
(d) From Exhibit___(APD/RBM-1, Schedule 2 ECCR) page 5 of 7
(e) From Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1) page 1 of 14
(f) From Exhibit___(APD/RBM-1, Schedule 2 ECCR) page 1 of 7
(g) From Exhibit___(APD/RBM-1, Schedule 4 DSM) page 1 of 4

GEORGIA POWER COMPANY

DETAIL COMPUTATION OF THE CALENDAR YEAR RETAIL REVENUE DEFICIENCY
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

OPERATING INCOME

	ADJUSTED TOTAL COMPANY (Section 3)	UPS, WHOLESALE BLOCKS, & DALTON	ADJUSTED TOTAL COMPANY LESS WHSL	RETAIL ALLOCATOR	ADJUSTED RETAIL
OPERATING REVENUES:					
Sales of Electricity	7717229	-517703	7199526		7192957
Other Operating Reve	263001.2	-27679	235322.2	0.9995	235204
TOTAL OPERATING I	7980230	-545382	7434848		7428161
EXPENSES:					
OPERATING EXPENSES:					
Generation - Fixed	391456.4	-24536	366920.4	0.99951	366741
Generation - Fuel & V	3387301	-341860	3045441		3044156
Purchased Power - Fi	430490.5	-10415	420075.5	0.99952	419874
Purchased Power - Er	686139.1		686139.1	0.99956	685837
System Control & Loa	33776.06	0	33776.06	0.9995	33759
TOTAL PRODUCTION	4929163	-376811	4552352		4550367
Transmission	123235.1	-3118	120117.1	0.99959	120068
Distribution	265047.6		265047.6	0.99975	264981
Customer Accounting	163229.4		163229.4	1	163229
Customer Assistance	29624.08		29624.08	1	29624
Energy Services	42652.37		42652.37	1	42652
Administrative & Gene	427941.4	-13072	414869.4	0.99969	414741
TOTAL O & M	5980893	-393001	5587892		5585662
DEPRECIATION:					
Production	297711.1	-38012	259699.1	0.99951	259572
Transmission	96442.74	-4076	92366.74	0.99948	92319
Distribution	271976.5		271976.5	0.99977	271914
General & Intangible	43745.45	-804	42941.45	0.99976	42931
TOTAL DEPRECIATIO	709875.8	-42892	666983.8		666736
ARO Depreciation Ex	-63.396		-63.396	1	-63
ARO Depreciation Ex	2.244		2.244	1	2
ARO Depreciation Ex	1.872		1.872	1	2
ARO Depreciation Ex	38.028		38.028	1	38
ARO Accretion - Pro	49624		49624	0.99952	49600
ARO Accretion - Tra	72		72	1	72
ARO Accretion - Dist	48		48	1	48
ARO Accretion - Ger	461		461	1	461
ARO Deferral - Produ	-50179		-50179	0.99952	-50155
Total ARO	4.748	0	4.748		5
Nuclear Decommissio	1686		1686	0.99941	1685
Taxes Other Than Inc	171204.2	-4814	166390.2	0.99959	166322
Amortization of Investi	-12202	610	-11592	0.99957	-11587
Amortization of Deferr	4165.232		4165.232	0.99952	4163
Amortization of Deferr	-86657		-86657	0.99945	-86609
Amortization of Firm T	0		0	0	0
Amortization of Hamm	5415		5415	0.99945	5412
Amortization / Deferra	0		0	0.99948	0
Amortization of M&S I	1080		1080	0.99907	1079
Amortization / Deferra	0		0	1	0
Amortization of COR	-30824.7		-30824.7	0.99968	-30815
Income Taxes	321049.8	-33943	287106.8	*	285741.3
TOTAL EXPENSES	7065690	-474040	6591650		6587794
OPERATING INCOME	914539.7	-71342	843197.8		840366.5
Interest Accretion on E	0		0	1	0
Interest on Customer I	-4476.07		-4476.07	1	-4476
TOTAL RETURN	910063.7	-71342	838721.7		835890.5
RATE OF RETURN	0.0685		0.066		0.065878

GEORGIA POWER COMPANY

DETAIL COMPUTATION OF THE CALENDAR YEAR RETAIL REVENUE DEFICIENCY
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

AVERAGE RATE BASE

	ADJUSTED TOTAL COMPANY (Section 3)	UPS, WHOLESALE BLOCKS, & DALTON	ADJUSTED TOTAL COMPANY LESS WHSL	RETAIL ALLOCATOR	ADJUSTED RETAIL
PLANT-IN-SERVICE:					
Steam	4915072	-861683	4053389	0.99952	4051443
Nuclear	4241040		4241040	0.99952	4239004
Hydro	684899.2		684899.2	0.99952	684570
Other (CTs)	1135530		1135530	0.99952	1134985
TOTAL PRODUCTION	10976541	-861683	10114858		10110002
Transmission	4291850	-182979	4108871	0.99947	4106694
Distribution	7937715		7937715	0.99975	7935731
General	1052248	-12549	1039699	0.99973	1039419
Intangible	307264.8	-2669	304595.8	0.99973	304514
ARO Plant in Service -	20785.68		20785.68	0.99952	20776
ARO Plant in Service -	12766.11		12766.11	0.99953	12760
ARO Plant in Service -	264.4775		264.4775	1	264
ARO Plant in Service -	159.1965		159.1965	1	159
ARO Plant in Service -	109.0346		109.0346	1	109
ARO Plant in Service -	2506.559		2506.559	0.9996	2506
TOTAL GROSS PLAN	24602211	-1059880	23542331		23532934
Nuclear Fuel	561163.4		561163.4	0.99952	560894
Nuclear CWIP	0		0	0.99952	0
Electric Plant Held For	93921.24		93921.24	1	93921
TOTAL ELECTRIC PL	25257295	-1059880	24197415		24187749
ACCUMULATED DEPRECIATION:					
Production	5618590	-427418	5191172	0.99952	5188680
Transmission	1189292	-52150	1137142	0.99946	1136528
Distribution	2785166		2785166	0.99976	2784498
General	411989.4	-4951	407038.4	0.99973	406929
Intangible	212282.8	-1844	210438.8	0.99972	210380
ARO Accumulated De	47031.46		47031.46	0.99951	47008
ARO Accumulated De	82.81125		82.81125	1	83
ARO Accumulated De	69.64206		69.64206	1	70
ARO Accumulated De	1992.316		1992.316	0.99949	1991
SUBTOTAL ACCUM.	10266496	-486363	9780133		9776167
Nuclear Fuel Amortiza	227259.5		227259.5	0.99952	227150
TOTAL ACCUMULATI	10493755	-486363	10007392		10003317
NET PLANT-IN-SERV	14763540	-573517	14190023		14184432
Fuel and Materials & S	911430	-61802	849628	0.99954	849237
Payables Associated v	-1089		-1089	1	-1089
Min Bank Balances, P	89920.51	-536	89384.51	0.99959	89348
Prepaid Pension Cost	519874.6	-24784	495090.6	0.99972	494952
Customer Deposits	-242108		-242108	1	-242108
Accum Interest on Cus	-26135		-26135	1	-26135
Operating Reserves	-214622	6176	-208446	0.99975	-208394
Accumulated Deferred Income Taxes:					
Accelerated Amortiza	-332313	0	-332313	0.99959	-332177
Other Property (282)	-2508958	82955	-2426003	0.99959	-2425009
Other (283)	-394590	10519	-384071	0.99966	-383940
Prepaid (190)	460457.2	-10350	450107.2	0.9997	449972
Accum Deferred Inves	0		0	1	0

ARO Regulatory Asset	816967.7		816967.7	0.99944	816510
ARO Liability (230)	-795728		-795728	0.99944	-795283
ARO Regulatory Liabil	-125896		-125896	0.99951	-125834
Hammond Cooling Tov	11281.13		11281.13	0.99953	11276
Deferred DSM Costs	0		0	1	0
Reg Asset - Deferred I	56364		56364	0.99964	56344
Reg Asset - Deferred (	86508		86508	1	86508
Reg Asset - Firm Trans	0		0	0.99959	0
Green Energy Over/Ur	0		0	1	0
M&S Inventory Adjustr	4860		4860	0.99959	4858
ECCR Deferred Regul	0.461538		0.461538	0.99952	0
ECCR Regulatory Liab	0		0	0.99952	0
Deferred McIntosh C I	5275.129		5275.129	0.99958	5273
Reg Liability - Non AR(	-77061.9		-77061.9	0.99968	-77037
Deferred Nuclear Outa	12927.53		12927.53	0.99949	12921
Cash Working Capital	260791.3		260791.3	*	243778
TOTAL RATE BASE	13281697	-571339	12710358		12688403

* Cash Working Capital is allocated to retail on the basis of Retail O&M expenses to Total O&M expenses.

GEORGIA POWER COMPANY
SUMMARY OF PROJECTIONS
TWELVE MONTHS ENDED DECEMBER 31, 2011
(AMOUNTS IN THOUSANDS)

LINE NO. (1)	DESCRIPTION (2)	TEST YEAR AS BUDGETED 12/31/2011 (3) (000)	ADJUSTMENTS (4) (000)		ACTUAL PRESENT RATES 12/31/2011 (5) (000)
	OPERATING REVENUES:				
1	Sales of Electricity	8088780	-371552	A/	7717229
2	Other Operating Reve	339925.7	-76924.6	B/	263001.2
3	Total Operating Rever	8428706	-448476		7980230
	OPERATING EXPENSES:				
4	Total Operation and M	6057982	-77089.1	C/	5980893
5	Depreciation and Amo	808879.7	-98999.9	D/	709879.8
6	Nuclear Decommissio	3462	-1776	E/	1686
7	Taxes Other Than Inc	346413.4	-175209	F/	171204.2
8	Amortization of Investr	-13164	962	G/	-12202
9	Amortization of Deferr	0	-86657	H/	-86657
10	Amortization / Deferral	0	4165.232	I/	4165.232
11	Amortization of Hamm	0	5415	J/	5415
12	Amortization / Deferral	0	0		0
13	Amortization of M&S Ir	0	1080	K/	1080
14	Amortization / Deferral	0	0		0
15	Amortization of Cost o	0	-30824.7	L/	-30824.7
16	Federal Income Taxes	160637.1	79157.4	M/	239794.5
17	State Income Taxes P	-29596	26368.62	N/	-3227.36
18	Deferred Income Taxe	147220.7	-62738	O/	84482.65
19	Total Operating Exper	7481835	-416146		7065690
20	Total Operating Incom	946871	-32330.5		914540.5
21	Interest Accretion on E	0	0		0
22	Interest on Customer I	-4476.07	0		-4476.07
23	Total Return	942394.9	-32330.5		910064.4

	RATE BASE:	13 MONTH AVERAGE PER BOOKS			13 MONTH AVERAGE PRESENT RATES
	PLANT-IN-SERVICE:	12/31/2011	ADJUSTMENTS		12/31/2011
20	Electric Plant-in-Servic	27960606	-3358396	P/	24602211
21	Nuclear Fuel	561163.4	0		561163.4
22	Electric Plant Held For	93921.24	0		93921.24
23	Plant-in-Service	28615691	-3358396		25257295
24	Accum. Prov. for Depr	10546023	-279527	Q/	10266496

25	Accum. Prov. for Nucl	227259.5	0		227259.5
26	Total Accum. Prov. for	10773283	-279527		10493755
27	Net Plant-in-Service	17842408	-3078869		14763540
28	Fuel and Materials & S	883152.3	28277.78	R/	911430
30	Payables Associated v	-1089	0		-1089
31	Minimum Bank Balanc	89920.51	0		89920.51
32	Prepaid Pension Asse	519874.6	0		519874.6
33	Customer Deposits	-242108	0		-242108
34	Accumulated Interest (	-26135	0		-26135
35	Operating Reserves	-214622	0		-214622
36	Accumulated Deferred Income Taxes:				
37	Accelerated Amortiza	-332313	0		-332313
38	Other Property (282)	-2746641	237682.7	S/	-2508958
39	Other (283)	-299524	-95065.8	T/	-394590
40	Prepaid (190)	427012	33445.24	U/	460457.2
41	Accumulated Deferred	0	0		0
42	ARO Regulatory Asset	21239.57	0		21239.57
43	ARO Liability (254)	-644022	518125.4	V/	-125896
44	Hammond Cooling To	13537.13	-2256	W/	11281.13
45	Deferred DSM Costs	0	0		0
46	Regulatory Asset - De	0	56364	X/	56364
47	Reg Asset - Deferred (	0	86508	Y/	86508
48	Green Energy Over/Ur	-450	450	Z/	0
49	M&S Inventory Adjustr	0	4860	AA/	4860
50	ECCR Deferred Regul	1014.462	-1014.46	AB/	0
51	ECCR Regulatory Liab	0	0		0
52	Deferred McIntosh C I	5275.129	0		5275.129
53	Reg Liability - Non-AR	0	-77061.9	AC/	-77061.9
54	Deferred Nuclear Outa	12927.53	0		12927.53
55	Cash Working Capital	200844.1	59947.2	AD/	260791.3
56	TOTAL RATE BASE	15510302	-2228606		13281696
57	RATE OF RETURN	0.060759			0.06852

GEORGIA POWER COMPANY

DERIVATION OF INCOME EXPANSION FACTOR
ESTIMATED FOR THE TWELVE MONTHS ENDING JULY 31, 2011

1	Additional Revenue				1
2	Less:				
	Federal and State Income Taxes				-0.38679
	Net After Income Taxes				0.61321
3	Less:				
	Uncollectible Accounts				
	Estimated Test Year Uncollectible Accounts Expense /	$	32994 =	0.004621	
	Estimated Test Year Retail Revenues (Excl Street & Hwy Lightni	$	7140663		
	Reduction in Income Taxes = .462% x 38.679%			-0.00179	
	Net Effect of Uncollectible Accounts				-0.00283
	Net After Income Taxes and Uncollectible Accounts				0.610377
4	Add:				
	Additional Compensation for Collecting State Sales Tax				
	Estimated Test Year Sales Tax on Revenue /	$	502104 =	0.069625	
	Estimated Test Year Retail Revenues	$	7211545		
	Collection Fee = 0.5%				
	Compensation Percentage = 6.963% x 0.5%			0.000348	
	Increase in Income Taxes = 0.035% x 38.679%			-0.00013	
	Net Effect of Additional Compensation				0.000213
5	After Tax Effect of Additional Revenue				0.61059

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

COMPUTATION OF THE IMPACT OF MUNICIPAL FRANCHISE FEES (MFF)
ESTIMATED FOR THE TWELVE MONTHS ENDING JULY 31, 2011
(Amounts in Thousands)

Line No.	Description		Amounts	
-1	-2		-3	
1	Total Budgeted Revenue Before MFF:	(a)	7213949	
2	% of Revenues Inside Municipalities	(b)	0.58	
3	Portion Inside the Municipalities:		4184091	
4	MFF Rate		0.04	
5	MFF Expenses			167363.6
6	MFF Expense Lead Days		-236.25	
7	Revenue Lag Days (c)		38.1	
8	Net Lag Days		-198.15	
9	Calendar Year Days		365	
10	Average MFF Working Capital		-90858	
11	Pre-Tax Weighted Average Cost of Capital (d)		0.1268	
12	Carrying Charge on Pro Forma Average MFF Working Capital			-11521
13	Adjusted Calendar Year - MFF Expenses			155842.6
14	Franchise Fees included in Current Rates			-151947
15	Additional MFF revenue requirement on existing rates			3895.209
16	MFF rate to be used on incremental revenue requirements		0.021603	
17	(155,843 / 7,213,949)			
18	Incremental MFF revenue requirement on Traditional Base Rate Tariff =			
19	$574,676 (e) x 2.16%			12414.65
20	Incremental MFF revenue requirement on ECCR = $181,317 (f) x 2.16%			3916.447
21	Incremental MFF revenue requirement on DSM = $31,673 (g) x 2.16%			684.2379
22	Total MFF Revenue Deficiency			20910.54

(a) From Test Period Forecasted Retail Revenues Less: Test Period Projected MFF
(b) From 2009 Percent of Revenues Located within Municipalities
(c) From Exhibit___(APD/RBM-3, Schedule 4) page 35 of 35
(d) From E From Exhibit___(APD/RBM-3, Schedule 2 ECCR) page 4 of 4
(e) From Exhibit____(APD/RBM-3, Schedule 1, Workpaper 1) page 1 of 3
(f) From Exhibit___(APD/RBM-3, Schedule 2 ECCR) page 1 of 4
(g) From E From Exhibit___(APD/RBM-3, Schedule 3 DSM) page 1 of 4

Calendar Year ADJUSTMENTS
(COLUMN 4)

FOOTNOTE A/ $ (371,552) Sales of Electricity

This adjustment reflects revenue sharing associated with Economy Energy Sales; removes revenues associated with the ECCR tariff, which are recovered through a separate tariff as established in Docket 25060; removes Southern Company Generation & Energy Marketing (SCGEM) wholesale transactions involving purchases and subsequent resale; budget correction for removal of revenues to be recovered through the DSM tariff; removes carrying costs on unrecovered fuel balances; and removes revenues collected under the MFF tariff, which are recovered through a separate tariff as established in Docket 25060.

Economy Energy Sales - Revenue Sharing	$ 3,416
ECCR Revenues	$ (214,724)
Southern Co. Generation & Energy Marketing	2,596
Budget Corrections - DSM revenues	(2,403)
Unrecovered Fuel Balances - Carrying Costs	(6,141)
Municipal Franchise Fees	(154,295)
TOTAL	$ (371,552)

FOOTNOTE B/ $ (76,925) Other Operating Revenues

This adjustment removes revenues associated with Unregulated Outdoor Lighting in accordance with the Commission's Order in Docket 3936; reflects the impact of revenue sharing for wireless co-location; adjusts municipal franchise fees for unregulated outdoor lighting revenues; and removes revenues associated with fees charged to lake lot lessees, as established in Docket 25060.

Unregulated Outdoor Lighting	$ (77,730)
Wireless Co-Location Revenues	(118)
Municipal Franchise Fees	1,805
FERC Boundary Land Fees	(881)
TOTAL	$ (76,925)

FOOTNOTE C/ $ (77,089) Total Operation and Maintenance Expenses

The adjustment reflects treatment of the Corporate Headquarters as an operating lease; treatment of the Rome Headquarters Building as an operating lease; removes Institutional and Goodwill advertising; reflects the impact of Economy Energy revenue sharing; removes expenses for the Nuclear Energy Institute (NEI); removes expenses associated with the ECCR tariff; reflects delay in commercial operation of the McDonough combined cycle units in accordance with the Commission's Order in Docket 24506; reflects retirement of McDonough steam units; removes SCGEM expenses for wholesale activities; reflects reclassification of membership fees below the line; removes expenses for Unregulated Outdoor Lighting Services; regulatory treatment of Purchased Power Agreement Additional Sums; removes marketing costs to be recovered through separate

Demand Side Management (DSM) tariffs; includes estimated Commission consulting fees to be paid by the Company; and removes costs of maintaining FERC Boundary Land at Company lakes.

Corporate Headquarters Lease		$ 8,646
Rome Headquarters Building		342
Institutional & Goodwill Advertising		(12,114)
Economy Energy Sales - Revenue Sharing		4,555
Nuclear Energy Institute Fees		(737)
ECCR Costs		(84,460)
McDonough Combined Cycle Delay		19,524
McDonough Steam Retirement		4,800
Southern Co. Generation & Energy Marketing		(3,222)
Budget Corrections - Membership Fees & Dues		(56)
Unregulated Outdoor Lighting		(12,581)
Purchased Power Agreement Additional Sums		7,968
Marketing O&M Adjustment		(8,938)
Georgia Public Service Commission Consulting Fees		600
FERC Boundary Land Expenses		(1,415)
TOTAL		$ (77,089)

FOOTNOTE D/ $ (99,001) Depreciation Expense

These adjustments were made to reflect the Rome Headquarters building as an operating lease; remove depreciation associated with the ECCR tariff; reflect the delay of commercial operation for the McDonough combined cycle units; reflect the impact of proposed new depreciation rates; reflect impact of depreciation on budget correction for transmission plant in service; correct budgeted depreciation expense for Plant McDonough transmission investment; and remove expenses associated with Unregulated Outdoor Lighting.

Rome Headquarters Building		$ (95)
ECCR Removal		(83,610)
McDonough Combined Cycle Delay		(19,209)
Depreciation Study Update		19,112
Budget Corrections		(1,792)
McDonough Transmission Interconnection		120
Unregulated Outdoor Lighting		(13,525)
TOTAL		$ (99,000)

FOOTNOTE E/ $ (1,776) Nuclear Decommissioning Expense

This adjustment reduces the nuclear decommissioning accrual to the level necessary to fund the NRC minimum exclusive of site restoration costs. This is consistent with the Commission's Order in Docket 25060.

FOOTNOTE F/ $ (175,209) Taxes Other than Income Taxes

This adjustment removes budgeted Municipal Franchise Fees (MFF) to be recovered through a separate MFF tariff, and also removes costs associated with Outdoor Lighting Services in accordance with the Commission's Order issued in Docket 3936.

FOOTNOTE G/ $ 962 Amortization of Investment Tax Credits

This adjustment results from changes associated with the Depreciation Study and life extension adjustments related to changes in asset life spans.

FOOTNOTE H/ $(86,657) Amortization of Deferred Costs

This adjustment results from a one year deferral of depreciation expense primarily related to transmission and distribution plant added since the 2007 base rate case, the cost of which will be amortized over a five year period.

FOOTNOTE I/ $ 4,165 Amortization of Healthcare Costs

This adjustment results from changes in projected tax impacts on the Company's medical plans resulting from new healthcare legislation proposed to be amortized over the 12 year average remaining employee service life.

FOOTNOTE J/ $ 5,415 Amortization of Hammond Cooling Tower Rental

This adjustment reflects proposed three year amortization of deferred costs associated with the Hammond Cooling Tower Rental in accordance with the Commission's Order in Docket No. 26794.

FOOTNOTE K/ $ 1,080 Amortization of M&S Inventory - Steam

This adjustment reflects deferral and materials and supplies adjustments associated with the retirement of steam units at Plant McDonough and proposed five year amortization.

FOOTNOTE L/ $ (30,825) Amortization of Cost of Removal

This adjustment reflects the company's proposed three year amortization of the unused 2009 amounts authorized in Docket No. 25060 as well as additional proposed deferred non-ARO costs of removal.

FOOTNOTE M/ $ 79,157 Adjustment to Federal Income Taxes Payable

This adjustment results from the treatment of items referenced in FOOTNOTES A/ through L/ and the interest synchronization adjustment.

Corporate Headquarters Lease		$ (3,122)
Rome Headquarters Building		(113)
Institutional & Goodwill Advertising		4,000
Economy Energy Sales - Revenue Sharing		(376)
Nuclear Energy Institute Fees		243
ECCR Tariff Removal		48,270
McDonough Combined Cycle Delay		3,547
McDonough Steam Retirement		(1,906)
Nuclear Decommissioning Accrual Adjustment		586
Southern Co. Generation & Energy Marketing		1,921
Budget Corrections		2,318
McDonough Transmission Interconnection		(296)
Unregulated Outdoor Lighting		(9,006)
Purchased Power Agreement Additional Sums		(2,631)
Unrecovered Fuel Balances - Carrying Costs		(2,028)
Internal Revenue Code - Section 199 Adjustment		(5,837)
Marketing O&M Adjustment		2,951
Wireless Co-Location Revenues		(39)
Georgia Public Commission Consulting Fees		(198)
Municipal Franchise Fees		6,351
FERC Boundary Land Expenses		176
Interest Synchronization		34,346
TOTAL		$ 79,157

FOOTNOTE N/ $26,369 Adjustment to State Income Taxes Payable

This adjustment results from the treatment of items referenced in FOOTNOTES A/ through L/ and the interest synchronization adjustment.

Corporate Headquarters Lease	$	(533)
Rome Headquarters Building		(19)
Institutional & Goodwill Advertising		686
Economy Energy Sales - Revenue Sharing		(64)
Nuclear Energy Institute Fees		42
ECCR Tariff Removal		19,758
McDonough Combined Cycle Delay		608
McDonough Steam Retirement		(327)
Nuclear Decommissioning Accrual Adjustment		101
Southern Co. Generation & Energy Marketing		329
Budget Corrections		398
McDonough Transmission Interconnection		(51)
Unregulated Outdoor Lighting		(1,231)
Purchased Power Agreement Additional Sums		(451)
Unrecovered Fuel Balances - Carrying Costs		(348)
Marketing O&M Adjustment		506
Wireless Co-Location Revenues		(7)
Georgia Public Commission Consulting Fees		(34)
Municipal Franchise Fees		1,089
FERC Boundary Land Expenses		30
Interest Synchronization		5,887
TOTAL	$	26,369

FOOTNOTE O/ $ (62,738) Adjustment to Deferred Income Taxes

This adjustment results from the treatment of items referenced in FOOTNOTES A/ through M/ and the interest synchronization adjustment.

Corporate Headquarters Lease	$	310
Rome Headquarters Building		33
ECCR Tariff Removal		(83,365)
McDonough Combined Cycle Delay		(4,631)
McDonough Steam Retirement		(42)
Depreciation Study Update		(6,913)
Unamortized Cost of Removal Adjustment		11,923
Amortization of Deferred Costs		31,736
McDonough Transmission Interconnection		300
Healthcare Legislation Tax Adjustment		(1,611)
Unregulated Outdoor Lighting		(8,383)
Regulatory Accruals Adjustment		(2,095)
TOTAL	$	(62,738)

FOOTNOTE P/ $ (3,358,396) Electric Plant-in-Service

The adjustment to electric-plant-in-service results from removal of investment associated with treatment of the Corporate Headquarters capital lease as an operating lease; from the treatment of the Rome Headquarters building as an operating lease; removal of investment related to the ECCR; correction of budgeted plant closures associated with contributions in aid of construction; delayed in-service dates of McDonough Combined Cycle units and the delay of the McDonough steam units retirement; McDonough transmission interconnection facilities in-service dates; and removal of investment associated with Unregulated Outdoor Lighting.

Corporate Headquarters Lease	$ (56,464)
Rome Headquarters Building	(5,209)
ECCR Tariff Removal	(2,244,651)
McDonough Combined Cycle Delay	(695,714)
McDonough Steam Retirement	(14,805)
Budget Corrections	(63,933)
McDonough Transmission Interconnection	3,986
Unregulated Outdoor Lighting	(281,606)
TOTAL	$ (3,358,396)

FOOTNOTE Q/ $ (279,527) Accumulated Reserve for Depreciation

These adjustments remove accumulated reserve associated with Unregulated Outdoor Lighting; reflect delay of commercial operation for the McDonough combined cycle units; correction of depreciation associated with plant closures adjustment noted in Footnote P/ above; reflect the Rome Headquarters building as an operating lease; reflect the impact of proposed new depreciation rates; and correct budgeted accumulated reserve for Plant McDonough transmission investment.

Rome Headquarters Building	$ (965)
ECCR Tariff Removal	$ (193,180)
McDonough Combined Cycle Delay	(7,072)
McDonough Steam Retirement	(12,734)
Depreciation Study Update	18,333
Budget Correction	(1,619)
McDonough Transmission Interconnection	501
Unregulated Outdoor Lighting	(82,791)
TOTAL	$ (279,527)

FOOTNOTE R/ $28,728 Fuel and Materials & Supplies Inventory

This adjustment reflects budget corrections associated with coal, gas, and emissions inventories; and removal of inventories associated with Unregulated Outdoor Lighting.

FOOTNOTE S/ $ 237,683 Adjustment to Accumulated Deferred Income Taxes – Account 282 – Other Property

This adjustment results primarily from the impact of ADITs associated with the removal of the ECCR tariff and unregulated outdoor lighting.

FOOTNOTE T/	$ (95,066)	Adjustment to Accumulated Deferred Income Taxes – Account 283 – Other

This adjustment results primarily from the impact of ADITs associated with the deferral of depreciation costs as noted in Footnote H/; and the amortization of healthcare costs as noted in Footnote I/.

FOOTNOTE U/	$ 33,445	Adjustment to Accumulated Deferred Income Taxes – Account 190 – Prepaid

This adjustment results primarily from the impact of ADITs associated with proposed additional non-ARO cost of removal deferrals.

FOOTNOTE V/	$ 518,125	Asset Retirement Obligation Regulatory Liability

This adjustment reflects the removal of the external nuclear decommissioning reserve from the Asset Retirement Obligation regulatory liability. This amount has been funded externally and as a result should not be applied as a reduction to rate base.

FOOTNOTE W/	$ (2,256)	Hammond Cooling Tower Rental

This adjustment reflects proposed amortization of deferred costs associated with the Hammond Cooling Tower Rental

FOOTNOTE X/	$ 56,364	Reg. Asset – Deferred Income Tax (FAS 158)

This adjustment reflects the expected tax impacts of current healthcare legislation.

FOOTNOTE Y/	$ 86,508	Reg. Asset – Deferred Costs (182)

This adjustment reflects the one year deferral of depreciation costs as noted in FOOTNOTE H/.

FOOTNOTE Z/	$450	Green Energy Over/Under Recovery

This adjustment reflects a budget correction associated with Green Energy.

FOOTNOTE AA/	$ 4,860	Materials & Supplies Inventory Adjustment - Steam

This adjustment reflects proposed deferral and subsequent amortization of materials and supplies associated with Plant McDonough as noted in FOOTNOTE K/.

FOOTNOTE AB/	$ (1,014)	ECCR Deferred Regulatory Asset

This adjustment reflects the impact of a budget correction to ECCR deferrals.

FOOTNOTE AC/	$ (77,062)	Regulatory Liability – Non-ARO Cost of Removal

This adjustment reflects the adjusted Non-ARO Costs of Removal amortization, as noted in FOOTNOTE L/.

FOOTNOTE AD/	$ 59,947	Cash Working Capital Adjustment

This adjustment reflects the effect on cash working capital due to the above adjustments.

GEORGIA POWER COMPANY

COMPUTATION OF THE CALENDAR YEAR RETAIL REVENUE DEFICIENCY
APPLICABLE TO TRADITIONAL BASE RATE TARIFFS
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2012 (a)
(Amounts in Thousands)

LINE NO. (1)	DESCRIPTION (2)	TOTAL REVENUE DEFICIENCY (3)	
1	Retail Rate	$ 12910418	(b)
2	Requested	x 0.0892	(c)
3	Earnings	$ 1151609	
4	Deduct: Earnings Avai	794825.9	(d)
5	Earnings D	$ 356783.3	
6	Income Ex	÷ 0.610545	(e)
7	Revenue D	$ 584368.2	
8	Less: 2011 Revenue D	451461.5	(f)
9	2012 Incremental Rev	132906.6	

(a) Revenue Requirements will be projected annually based on updated budgets. Amounts reflected are based on the 2010 budget. No rate adjustments will be requested unless projected earnings are outside the allowed ROE range approved in this case.

(b) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 2) page 4 of 6
(c) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 2) page 5 of 6
(d) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 2) page 3 of 6
(e) From E
(f) From E

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

DERIVATION OF INCOME EXPANSION FACTOR
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2012

1	Additional Revenue				1
2	Less:				
	Federal and State Income Taxes				-0.38679
	Net After Income Taxes				0.61321
3	Less:				
	Uncollectible Accounts				
	Estimated Calendar Year Uncollectible Accounts Expense /	$	34942 =	0.004695	
	Estimated Calendar Year Retail Revenues (Excl Street & Hwy Li	$	7441955		
	Reduction in Income Taxes = 0.470% x 38.679%			-0.00182	
	Net Effect of Uncollectible Accounts				-0.00288
	Net After Income Taxes and Uncollectible Accounts				0.610331
4	Add:				
	Additional Compensation for Collecting State Sales Tax				
	Estimated Calendar Year Sales Tax on Revenue /	$	523181 =	0.069625	
	Estimated Calendar Year Retail Revenues	$	7514264		
	Collection Fee = 0.5%				
	Compensation Percentage = 6.963% x 0.5%			0.00035	
	Increase in Income Taxes = 0.035% x 38.679%			-0.00014	
	Net Effect of Additional Compensation				0.000215
5	After Tax Effect of Additional Revenue				0.610545

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

DETAIL COMPUTATION OF THE CALENDAR YEAR RETAIL REVENUE DEFICIENCY
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2012
(Amounts in Thousands)

OPERATING INCOME

	ADJUSTED TOTAL COMPANY (Section 3)	UPS, WHOLESALE BLOCKS, & DALTON	ADJUSTED TOTAL COMPANY LESS WHSL	RETAIL ALLOCATOR	ADJUSTEI RETAIL
OPERATING REVENUES:					
Sales of Electricity	8139588	-518517	7621071		7609174
Other Operating Revei	266992.5	-28285	238707.5	0.9995	238588
TOTAL OPERATING I	8406580	-546802	7859778		7847762
EXPENSES:					
OPERATING EXPENSES:					
Generation - Fixed	398813.8	-23930	374883.8	0.99951	374700
Generation - Fuel & Va	3676984	-337035	3339949		3338540
Purchased Power - Fix	381739.9	-10471	371268.9	0.99952	371091
Purchased Power - En	732139		732139	0.99956	731817
System Control & Loac	34041.92	0	34041.92	0.9995	34025
TOTAL PRODUCTION	5223718	-371436	4852282		4850173
Transmission	127185.1	-3011	124174.1	0.99959	124123
Distribution	274976.3		274976.3	0.99975	274908
Customer Accounting	165310.3		165310.3	1	165310
Customer Assistance	31370.66		31370.66	1	31371
Energy Services	44540.69		44540.69	1	44541
Administrative & Gene	468920.4	-13538	455382.4	0.99969	455241
TOTAL O & M	6336022	-387985	5948037		5945667
DEPRECIATION:					
Production	304429.1	-36467	267962.1	0.99951	267831
Transmission	100419.6	-3906	96513.58	0.99948	96463
Distribution	284160.9		284160.9	0.99977	284096
General & Intangible	49570.65	-785	48785.65	0.99976	48774
TOTAL DEPRECIATIC	738580.2	-41158	697422.2		697164
ARO Depreciation Ex	-237.071		-237.071	1	-237
ARO Depreciation Ex	2.244		2.244	1	2
ARO Depreciation Ex	1.872		1.872	1	2
ARO Depreciation Ex	38.028		38.028	1	38
ARO Accretion - Proc	52877		52877	0.99952	52852
ARO Accretion - Trar	72		72	1	72
ARO Accretion - Distı	48		48	1	48
ARO Accretion - Gen	478		478	1	478
ARO Deferral - Produ	-53280		-53280	0.99952	-53254
Total ARO	0.073	0	0.073		1
Nuclear Decommissior	1686		1686	0.99941	1685
Taxes Other Than Inc	185989	-4849	181140	0.99959	181066
Amortization of Investr	-12163.4	596	-11567.4	0.99957	-11562
Amortization of Deferre	4165.232		4165.232	0.99952	4163
Amortization of Deferre	17331.4		17331.4	0.99945	17322
Amortization of Firm Tı	0		0	0	0
Amortization of Hamm	5415		5415	0.99945	5412
Amortization / Deferral	0		0	0.99948	0
Amortization of M&S Ir	1080		1080	0.99907	1079
Amortization / Deferral	0		0	1	0
Amortization of COR	-30824.7		-30824.7	0.99968	-30815
Income Taxes	276809.3	-36725.5	240083.9		236742.1
TOTAL EXPENSES	7524090	-470121	7053969		7047924
OPERATING INCOME	882490.4	-76680.5	805809.8		799837.9
Interest Accretion on E	0		0	1	0
Interest on Customer I	-5011.86		-5011.86	1	-5012
TOTAL RETURN	877478.5	-76680.5	800798		794825.9
RATE OF RETURN	0.065		0.0619		0.061565

GEORGIA POWER COMPANY

DETAIL COMPUTATION OF THE CALENDAR YEAR RETAIL REVENUE DEFICIENCY
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2012
(Amounts in Thousands)

AVERAGE RATE BASE

	ADJUSTED TOTAL COMPANY (Section 3)	UPS, WHOLESALE BLOCKS, & DALTON	ADJUSTED TOTAL COMPANY LESS WHSL	RETAIL ALLOCATOR	ADJUSTED RETAIL
PLANT-IN-SERVICE:					
Steam	4849310	-863455	3985855	0.99952	3983942
Nuclear	4291936		4291936	0.99952	4289876
Hydro	688020.4		688020.4	0.99952	687690
Other (CTs)	1187924		1187924	0.99952	1187354
TOTAL PRODUCTION	11017191	-863455	10153736		10148862
Transmission	4482854	-176138	4306716	0.99947	4304433
Distribution	8338518		8338518	0.99975	8336434
General	1084444	-12209	1072235	0.99973	1071946
Intangible	334259	-2747	331512	0.99973	331422
ARO Plant in Service -	19758.68		19758.68	0.99952	19749
ARO Plant in Service -	12766.11		12766.11	0.99953	12760
ARO Plant in Service -	264.4775		264.4775	1	264
ARO Plant in Service -	159.1965		159.1965	1	159
ARO Plant in Service -	109.0346		109.0346	1	109
ARO Plant in Service -	2506.559		2506.559	0.9996	2506
TOTAL GROSS PLAN	25292830	-1054549	24238281		24228644
Nuclear Fuel	641562.8		641562.8	0.99952	641255
Nuclear CWIP	0		0	0.99952	0
Electric Plant Held For	93921.24		93921.24	1	93921
TOTAL ELECTRIC PL	26028314	-1054549	24973765		24963820
ACCUMULATED DEPRECIATION:					
Production	5758290	-432711	5325579	0.99952	5323023
Transmission	1268642	-51171	1217471	0.99946	1216814
Distribution	2987600		2987600	0.99976	2986883
General	444900.9	-5077	439823.9	0.99973	439705
Intangible	225054.3	-1850	223204.3	0.99972	223142
ARO Accumulated De	43182.06		43182.06	0.99951	43161
ARO Accumulated De	85.04601		85.04601	1	85
ARO Accumulated De	71.5209		71.5209	1	72
ARO Accumulated De	2025.339		2025.339	0.99949	2024
SUBTOTAL ACCUM. I	10729852	-490809	10239043		10234909
Nuclear Fuel Amortiza	286516.7		286516.7	0.99952	286379
TOTAL ACCUMULATI	11016368	-490809	10525559		10521288
NET PLANT-IN-SERV	15011946	-563740	14448206		14442532
Fuel and Materials & S	926627.6	-59593	867034.6	0.99954	866636
Payables Associated v	-1115.38		-1115.38	1	-1115
Min Bank Balances, P	60152.53	-534	59618.53	0.99959	59594
Prepaid Pension Cost	522624.8	-23595	499029.8	0.99972	498890
Customer Deposits	-271088		-271088	1	-271088
Accum Interest on Cus	-26135		-26135	1	-26135
Operating Reserves	-236857	5408	-231449	0.99975	-231391

Accumulated Deferred Income Taxes:					
Accelerated Amortiza	-396190	0	-396190	0.99959	-396028
Other Property (282)	-2453511	82835	-2370676	0.99959	-2369704
Other (283)	-369267	10262	-359005	0.99966	-358883
Prepaid (190)	461475	-9446	452029	0.9997	451893
Accum Deferred Inves	0		0	1	0
ARO Regulatory Asse	861867.9		861867.9	0.99944	861385
ARO Liability (230)	-840756		-840756	0.99944	-840285
ARO Regulatory Liabil	-136052		-136052	0.99951	-135985
Hammond Cooling To	5866.278		5866.278	0.99953	5864
Deferred DSM Costs	0		0	1	0
Reg Asset - Deferred I	51463		51463	0.99964	51444
Reg Asset - Deferred (	78499.45		78499.45	1	78499
Reg Asset - Firm Tran	0		0	0.99959	0
Green Energy Over/Ur	0		0	1	0
M&S Inventory Adjustr	3780		3780	0.99959	3778
ECCR Deferred Regul	0		0	0.99952	0
ECCR Regulatory Liab	0		0	0.99952	0
Deferred McIntosh C I	1717.552		1717.552	0.99958	1717
Reg Liability - Non AR	-46237.2		-46237.2	0.99968	-46222
Deferred Nuclear Outa	13173.24		13173.24	0.99949	13167
Cash Working Capital	268160.3		268160.3	*	251855
TOTAL RATE BASE	13490145	-558403	12931742		12910418

* Cash Working Capital is allocated to retail on the basis of Retail O&M expenses to Total O&M expenses.

GEORGIA POWER COMPANY

DETAIL COMPUTATION OF THE CALENDAR YEAR RETAIL REVENUE DEFICIENCY
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2012
(Amounts in Thousands)

Line No.	Component	Proportion	Cost	Component
1	Long-Term Debt	0.4651	0.0578	0.0269
2	Preferred Sec. (a)	0.0092	0.0822	0.0008
3	Preferred Stock	0.0024	0.0613	0.0001
4	Preference Stock	0.0257	0.0757	0.0019
5	Common Equity	0.4976	0.1195	0.0595
6	TOTAL	1		0.0892

(a) Company Obligated Mandatorily Redeemable Preferred Securities of subsidiaries, substantially all of whose assets are Junior Subordinated Debentures or Notes.

GEORGIA POWER COMPANY

COMPUTATION OF THE IMPACT OF MUNICIPAL FRANCHISE FEES (MFF)
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2012
(Amounts in Thousands)

1	Incrementa	$	2870.783
2	Incrementa	$	2590.337
3	Incrementa	$	3807.497
4	Incrementa	$	361.476
5	Total MFF	$	9630.093

(a) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 1) page 3 of 14
(b) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 2) page 1 of 6
(c) From Exhibit____(APD/RBM-1, Schedule 2 ECCR) page 1 of 7
(d) From Exhibit____(APD/RBM-1, Schedule 3 CCCR) page 1 of 5 (increases occur throughout the year)
(e) From Exhibit____(APD/RBM-1, Schedule 4 DSM) page 1 of 4

GEORGIA POWER COMPANY

COMPUTATION OF THE CALENDAR YEAR RETAIL REVENUE DEFICIENCY
APPLICABLE TO TRADITIONAL BASE RATE TARIFFS
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2013 (a)
(Amounts in Thousands)

LINE NO. (1)	DESCRIPTION (2)		TOTAL REVENUE DEFICIENCY (3)	
1	Retail Rate	$	13237290	(b)
2	Requested	x	0.0896	(c)
3	Earnings	$	1186061	
4	Deduct: Earnings Avai		837403	(d)
5	Earnings D	$	348658.2	
6	Income Ex	÷	0.610595	(e)
7	Revenue D	$	571013.8	
8	Less: 2011 Revenue D		451462	(f)
9	Less: 2012 Revenue D		132907	(g)
10	2013 Incre	$	-13355.2	

(a) Revenue Requirements will be projected annually based on updated budgets. Amounts reflected are based on the 2010 budget. No rate adjustments will be requested unless projected earnings are outside the allowed ROE range approved in this case.

(b) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 3) page 4 of 6
(c) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 3) page 5 of 6
(d) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 3) page 3 of 6
(e) From E
(f) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 1) page 1 of 14
(g) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 2) page 1 of 6

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

DERIVATION OF INCOME EXPANSION FACTOR
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2013

1	Additional Revenue					1
2	Less:					
	Federal and State Income Taxes					-0.38679
	Net After Income Taxes					0.61321
3	Less:					
	Uncollectible Accounts					
	Estimated Calendar Year Uncollectible Accounts Expense /	$	36272	=	0.004615	
	Estimated Calendar Year Retail Revenues (Excl Street & Hwy Li	$	7860382			
	Reduction in Income Taxes = 0.461% x 38.679%				-0.00178	
	Net Effect of Uncollectible Accounts					-0.00283
	Net After Income Taxes and Uncollectible Accounts					0.61038
4	Add:					
	Additional Compensation for Collecting State Sales Tax					
	Estimated Calendar Year Sales Tax on Revenue /	$	552440	=	0.069625	
	Estimated Calendar Year Retail Revenues	$	7934505			
	Collection Fee = 0.5%					
	Compensation Percentage = 6.963% x 0.5%				0.000348	
	Increase in Income Taxes = 0.035% x 38.679%				-0.00013	
	Net Effect of Additional Compensation					0.000213
5	After Tax Effect of Additional Revenue					0.610594

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

DETAIL COMPUTATION OF THE CALENDAR YEAR RETAIL REVENUE DEFICIENCY
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2013
(Amounts in Thousands)

OPERATING INCOME

	ADJUSTED TOTAL COMPANY (Section 3)	UPS, WHOLESALE BLOCKS, & DALTON	ADJUSTED TOTAL COMPANY LESS WHSL	RETAIL ALLOCATOR	ADJUSTED RETAIL
OPERATING REVENUES:					
Sales of Electricity	8610924	-550228	8060696		8048634
Other Operating Revel	274090	-29053	245037	0.9995	244915
TOTAL OPERATING I	8885014	-579281	8305733		8293549
EXPENSES:					
OPERATING EXPENSES:					
Generation - Fixed	413862.3	-24567	389295.3	0.99951	389105
Generation - Fuel & Va	3976419	-354610	3621809		3620280
Purchased Power - Fi	351284.3	-11066	340218.3	0.99952	340055
Purchased Power - En	753595.5		753595.5	0.99956	753264
System Control & Loa	34398.94	0	34398.94	0.9995	34382
TOTAL PRODUCTION	5529560	-390243	5139317		5137086
Transmission	132101.5	-3134	128967.5	0.99959	128915
Distribution	283082.8		283082.8	0.99975	283012
Customer Accounting	167448.3		167448.3	1	167448
Customer Assistance	32421.98		32421.98	1	32422
Energy Services	45902.8		45902.8	1	45903
Administrative & Gene	506985.9	-14169	492816.9	0.99969	492664
TOTAL O & M	6697503	-407546	6289957		6287450
DEPRECIATION:					
Production	310634.2	-34625	276009.2	0.99951	275874
Transmission	104853.6	-4046	100807.6	0.99948	100755
Distribution	296749.9		296749.9	0.99977	296682
General & Intangible	52123.84	-771	51352.84	0.99976	51341
TOTAL DEPRECIATIO	764361.5	-39442	724919.5		724652
ARO Depreciation Ex	-480.216		-480.216	1	-480
ARO Depreciation Ex	2.244		2.244	1	2
ARO Depreciation Ex	1.872		1.872	1	2
ARO Depreciation Ex	38.028		38.028	1	38
ARO Accretion - Proc	56349		56349	0.99952	56322
ARO Accretion - Trar	78		78	1	78
ARO Accretion - Dist	48		48	1	48
ARO Accretion - Gen	498		498	1	498
ARO Deferral - Produ	-56534		-56534	0.99952	-56507
Total ARO	0.928	0	0.928		1
Nuclear Decommissioning Expense			1686	0.99941	1685
Taxes Other Than Inc	196801.6	-4955	191846.6	0.99959	191768
Amortization of Investr	-11959.7	591	-11368.7	0.99957	-11364
Amortization of Deferr	4165.232		4165.232	0.99952	4163
Amortization of Deferr	17331.4		17331.4	0.99945	17322
Amortization of Firm T	0		0	0	0
Amortization of Hamm	5415		5415	0.99945	5412
Amortization / Deferral	0		0	0.99948	0
Amortization of M&S I	1080		1080	0.99907	1079

Amortization / Deferral	0		0	1	0
Amortization of COR	-30824.7		-30824.7	0.99968	-30815
Income Taxes	305080.6	-42555.8	262524.8		259180.3
TOTAL EXPENSES	7950641	-493908	7456733		7450534
OPERATING INCOME	934373.4	-85373.2	849000.3		843015
Interest Accretion on E	0		0	1	0
Interest on Customer I	-5611.79		-5611.79	1	-5612
TOTAL RETURN	928761.6	-85373.2	843388.5		837403
RATE OF RETURN	0.0673		0.0636		0.063261

GEORGIA POWER COMPANY

DETAIL COMPUTATION OF THE CALENDAR YEAR RETAIL REVENUE DEFICIENCY
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2013
(Amounts in Thousands)

AVERAGE RATE BASE

	ADJUSTED TOTAL COMPANY (Section 3)	UPS, WHOLESALE BLOCKS, & DALTON	ADJUSTED TOTAL COMPANY LESS WHSL	RETAIL ALLOCATOR	ADJUSTED RETAIL
PLANT-IN-SERVICE:					
Steam	4963870	-856753	4107117	0.99952	4105146
Nuclear	4375054		4375054	0.99952	4372954
Hydro	691343.3		691343.3	0.99952	691011
Other (CTs)	1231224		1231224	0.99952	1230633
TOTAL PRODUCTION	11261492	-856753	10404739		10399744
Transmission	4689466	-182792	4506674	0.99947	4504285
Distribution	8747917		8747917	0.99975	8745730
General	1112011	-11976	1100035	0.99973	1099738
Intangible	345956.4	-2670	343286.4	0.99973	343194
ARO Plant in Service -	17449.68		17449.68	0.99952	17441
ARO Plant in Service -	12766.11		12766.11	0.99953	12760
ARO Plant in Service -	264.4775		264.4775	1	264
ARO Plant in Service -	159.1965		159.1965	1	159
ARO Plant in Service -	109.0346		109.0346	1	109
ARO Plant in Service -	2506.559		2506.559	0.9996	2506
TOTAL GROSS PLAN	26190097	-1054191	25135906		25125930
Nuclear Fuel	744408		744408	0.99952	744051
Nuclear CWIP	0		0	0.99952	0
Electric Plant Held For	93921.24		93921.24	1	93921
TOTAL ELECTRIC PL	27028426	-1054191	25974235		25963902
ACCUMULATED DEPRECIATION:					
Production	6009998	-440395	5569603	0.99952	5566929
Transmission	1357327	-54010	1303317	0.99946	1302614
Distribution	3197108		3197108	0.99976	3196341
General	467887.7	-5142	462745.7	0.99973	462621
Intangible	240620.2	-1859	238761.2	0.99972	238694
ARO Accumulated De	39333.66		39333.66	0.99951	39314
ARO Accumulated De	87.28077		87.28077	1	87
ARO Accumulated De	73.39974		73.39974	1	73
ARO Accumulated De	2058.362		2058.362	0.99949	2057
SUBTOTAL ACCUM.	11314494	-501406	10813088		10808730
Nuclear Fuel Amortiza	358386.3		358386.3	0.99952	358214
TOTAL ACCUMULATI	11672881	-501406	11171475		11166944
NET PLANT-IN-SERV	15355546	-552785	14802761		14796958
Fuel and Materials & Supplies Inventory		-58687	872632.8	0.99954	872231
Payables Associated v	-1141		-1141	1	-1141
Min Bank Balances, P	61877.56	-503	61374.56	0.99959	61349
Prepaid Pension Cost	519975.7	-23668	496307.7	0.99972	496169
Customer Deposits	-303538		-303538	1	-303538
Accum Interest on Cus	-26135		-26135	1	-26135
Operating Reserves	-269264	4901	-264363	0.99975	-264297
Accumulated Deferred Income Taxes:					
Accelerated Amortiza	-462543	0	-462543	0.99959	-462353

Other Property (282)	-2378233	85167	-2293066	0.99959	-2292126
Other (283)	-348828	10265	-338563	0.99966	-338448
Prepaid (190)	462534	-9434	453100	0.9997	452964
Accum Deferred Inves	0		0	1	0
ARO Regulatory Asset	909615.3		909615.3	0.99944	909106
ARO Liability (230)	-888922		-888922	0.99944	-888424
ARO Regulatory Liabil	-145969		-145969	0.99951	-145898
Hammond Cooling Tov	451.4259		451.4259	0.99953	451
Deferred DSM Costs	0		0	1	0
Reg Asset - Deferred I	46562		46562	0.99964	46545
Reg Asset - Deferred (	64161.69		64161.69	1	64162
Reg Asset - Firm Tran	0		0	0.99959	0
Green Energy Over/Ur	0		0	1	0
M&S Inventory Adjustr	2700		2700	0.99959	2699
ECCR Deferred Regul	0		0	0.99952	0
ECCR Regulatory Liab	0		0	0.99952	0
Deferred McIntosh C I	239.5606		239.5606	0.99958	239
Reg Liability - Non AR	-15412.6		-15412.6	0.99968	-15408
Deferred Nuclear Outa	9917.269		9917.269	0.99949	9912
Cash Working Capital	279133.3		279133.3	*	262273
TOTAL RATE BASE	13804048	-544744	13259304		13237290

* Cash Working Capital is allocated to retail on the basis of Retail O&M expenses to Total O&M expenses.

GEORGIA POWER COMPANY

DETAIL COMPUTATION OF THE CALENDAR YEAR RETAIL REVENUE DEFICIENCY
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2013
(Amounts in Thousands)

Line No.	Component	Proportion	Cost	Component
1	Long-Term Debt	0.4657	0.059	0.0275
2	Preferred Sec. (a)	0.0086	0.0812	0.0007
3	Preferred Stock	0.0022	0.0613	0.0001
4	Preference Stock	0.0287	0.078	0.0022
5	Common Equity	0.4948	0.1195	0.0591
6	TOTAL	1		0.0896

(a) Company Obligated Mandatorily Redeemable Preferred Securities of subsidiaries, substantially all of whose assets are Junior Subordinated Debentures or Notes.

GEORGIA POWER COMPANY

COMPUTATION OF THE IMPACT OF MUNICIPAL FRANCHISE FEES (MFF)
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2013
(Amounts in Thousands)

1	Incrementa	$	-288.444
2	Incrementa	$	-262.915
3	Incrementa	$	1862.179
4	Incrementa	$	386.4456
5	Total MFF	$	1697.266

(a) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 1) page 3 of 14
(b) From Exhibit____(APD/RBM-1, Schedule 1, Workpaper 3) page 1 of 6
(c) From Exhibit____(APD/RBM-1, Schedule 2 ECCR) page 1 of 7
(d) From Exhibit____(APD/RBM-1, Schedule 3 CCCR) page 1 of 5 (increases occur throughout the year)
(e) From Exhibit____(APD/RBM-1, Schedule 4 DSM) page 1 of 4

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
PROJECTED ENVIRONMENTAL COMPLIANCE COST RECOVERY (ECCR) INCREASES EFFECTIVE 2011-2013
(Amounts in Thousands)

Line No.	Description	Levelized Docket No. 25060 ECCR Tariff	Revenue Available from Docket No. 25060 ECCR Tariff	Calendar Year Ending Dec-2011	Dec-2012	Dec-2013	
			Note 1		Note 2	Note 2	
1	Environmental Capital Costs (excl Book Depreciation)	$ 128,542	$ 124,155	$ 230,238	$ 226,080	$ 212,095	Note 3
2	Environmental Book Depreciation Expense	46,149	44,574	83,942	86,172	87,348	Note 3
3	Environmental O&M Expenses (incl Env Remediation)	47,621	45,996	84,796	96,507	99,870	Note 3
4	Amortization of 2010 Regulatory Asset (2011-2013)			7,588	7,587	7,586	Note 4
5	Return Required on Unamortized 2010 Regulatory Asset			1,473	894	299	Note 4
6	Total	$ 222,311	$ 214,724	$ 408,036	$ 417,239	$ 407,198	

		Incremental Change Without Depreciation and O&M Deferral - Effective Jan 1, 2011	Jan 1, 2012	Jan 1, 2013
			Note 2	Note 2
7	Environmental Capital Costs (excl Book Depreciation)	$ 106,084	$ (4,158)	$ (13,985)
8	Environmental Book Depreciation Expense	39,368	2,230	1,176
9	Environmental O&M Expenses (incl Env Remediation)	38,800	11,711	3,363
10	Amortization of 2010 Regulatory Asset (2011-2013)	7,588	(1)	(1)
11	Return Required on Unamortized 2010 Regulatory Asset	1,473	(579)	(595)
12	Total	$ 193,313	$ 9,203	$ (10,041)

		Incremental Change With Depreciation and O&M Deferral - Effective Jan 1, 2011	Jan 1, 2012	Jan 1, 2013	
			Note 2	Note 2	
13	Environmental Capital Costs (excl Book Depreciation)	$ 106,084	$ (4,158)	$ (13,985)	
14	Environmental Book Depreciation Expense		41,599	1,176	
15	Environmental O&M Expenses (incl Env Remediation)		50,511	3,363	
16	Amortization of 2010 Regulatory Asset (2011-2013)	7,588	(1)	(1)	
17	Return Required on Unamortized 2010 Regulatory Asset	1,473	(579)	(595)	
18	Amortization of 2011 Deferred O&M and Depreciation (2012-2014)		27,211	(2)	Note 5
19	Return Required on Unamortized 2011 Deferred O&M and Depreciation		5,340	(2,129)	Note 5
20	Total	$ 115,144	$ 119,923	$ (12,172)	

Note 1 - Based on the revenue forecast filed in Docket No. 31081, the ECCR tariff approved in Docket No. 25060 is projected to collect $214,724 in calendar year 2011.

Note 2 - These projections are based on the Company's 2010 budget. The 2012 and 2013 revenue requirements for the ECCR tariff will be updated through separate compliance filings based on updated revenue forecasts for the upcoming year, and actual financing costs for the previous year. The total projected environmental closures to plant and O&M expenses for 2011 - 2013 are provided in Volume 1, Exhibit 3, Supplemental Item S-49.

Note 3 - From page 2 of 7.

Note 4 - From page 3 of 7.

Note 5 - From page 4 of 7.

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
PROJECTED ENVIRONMENTAL COSTS 2011-2013 (Note 1)
(Amounts in Thousands)

	Calendar Years Ending 2011	2012	2013	
Retail Rate Base	$ 1,879,313	$ 1,841,542	$ 1,778,914	Note 2
Requested Rate of Return	8.76%	8.92%	8.96%	Note 3
Earnings Requirement	$ 164,628	$ 164,266	$ 159,391	
Deduct Earnings Available for Return	(78,944)	(85,300)	(84,428)	Note 4
Earnings Deficiency	$ 243,572	$ 249,566	$ 243,819	
Income Expansion Factor	61.049%	61.055%	61.059%	Note 5
Revenue Deficiency	**$ 398,976**	**$ 408,759**	**$ 399,313**	
Revenue Deficiency by Component:				
Environmental Capital Costs (excl Book Depreciation)	$ 230,238	$ 226,080	$ 212,095	
Environmental Book Depreciation Expense	83,942	86,172	87,348	
Environmental O&M Expenses (incl Env Remediation)	84,796	96,507	99,870	
Total	**$ 398,976**	**$ 408,759**	**$ 399,313**	

Note 1 - Calendar year revenue requirements are based on capital costs and O&M expenses provided in Volume 1, Exhibit 3, Supplemental Item S-49.

Note 2 - Rate base is based on the projected 13-month average balances of electric plant in service, accumulated depreciation and accumulated deferred income taxes for each period. Amounts used for retail revenue requirement calculations exclude wholesale allocations to UPS, Wholesale Block, and Dalton. (From page 6 of 7).

Note 3 - The retail revenue requirement rate will be based on the capital structure and costs approved by the Commission in the Company's most recent Annual Surveillance Report.

Note 4 - From page 6 of 7.

Note 5 - From Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1), Page 2 of 14, Exhibit___(APD/RBM-1, Schedule 1, Workpaper 2), Page 2 of 6, and Exhibit___(APD/RBM-1, Schedule 1, Workpaper 3), Page 2 of 6.

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
PROJECTED 2010 ENVIRONMENTAL COSTS & REGULATORY ASSET
(Amounts in Thousands)

	2010 Budget 2010	Docket No. 25060 2010	Regulatory Asset
Retail Electric Plant in Service (13-month average balance)	$ 1,994,388	$ 1,791,175	
Accumulated Depreciation	(114,968)	(108,789)	
Accumulated Deferred Income Taxes	(104,953)	(103,970)	
Net Rate Base	$ 1,774,468	$ 1,578,416	
Retail Revenue Requirement Rate	12.03%	12.52%	
Revenue Requirement on Net Rate Base	$ 213,468	$ 197,618	$ 15,851
Depreciation Expense	78,360	70,050	8,310
State Manufacturer's Investment Tax Credit	(11,983)	(8,396)	(3,587)
Revenue Requirement on Total Capital	**$ 279,846**	**$ 259,272**	**$ 20,573**
Operating Expenses	64,807	62,719	2,089
Total Revenue Requirement	**$ 344,653**	**$ 321,991**	**$ 22,662**

Amortization & Return Required on 2010 Regulatory Asset:	2011	2012	2013
Amortization of 2010 Regulatory Asset (2011-2013)	$ 7,588	$ 7,587	$ 7,586
Return Required on Unamortized 2010 Regulatory Asset:			
Unamortized Regulatory Asset (13-month average balance net of taxes	$ 11,580	$ 6,948	$ 2,316
Retail Revenue Requirement Rate (From page 5 of 7)	12.72%	12.86%	12.89%
Return Required on Unamortized 2010 Regulatory Asset	$ 1,473	$ 894	$ 299

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
PROJECTED 2011 DEFERRED O&M AND DEPRECIATION REGULATORY ASSET
(Amounts in Thousands)

	2011
Deferred Depreciation Expense (From page 1 of 7)	$ 39,368
Deferred Operating Expense (From page 1 of 7)	38,800
Subtotal Deferred Expenses	$ 78,168
Return Required on Deferred Expenses	3,110
Total Deferred Expense Regulatory Asset	**$ 81,279**

Amortization & Return Required on 2011 Deferred Expense Regulatory Asset:	2012	2013	2014
Amortization of 2011 Deferred Expense Regulatory Asset (2012-2014)	$ 27,211	$ 27,209	$ 27,209
Return Required on Unamortized Deferred Expense Regulatory Asset:			
Unamortized Deferred Expenses (13-month average balance net of taxes)	$ 41,527	$ 24,916	$ 8,305
Retail Revenue Requirement Rate (From page 5 of 7)	12.86%	12.89%	12.71%
Return Required on Unamortized Deferred Expense Regulatory Asset	$ 5,340	$ 3,212	$ 1,056

GEORGIA POWER COMPANY

ADJUSTED RETAIL RATE OF RETURN SUMMARY
PROJECTED FOR CALENDAR YEARS 2011 - 2013

Line No.	Component	Proportion	Average Cost	Average Component Cost	Revenue Requirement Rate
	Ending December 31, 2011 (Note 1)				
1	Long-Term Debt	46.19%	5.38%	2.49%	2.50%
2	Preferred Securities	0.98%	8.32%	0.08%	0.08%
3	Preferred Stock	0.26%	6.13%	0.02%	0.03%
4	Preference Stock	2.17%	7.13%	0.15%	0.25%
5	Common Equity	50.40%	11.95%	6.02%	9.86%
6	TOTAL	100.00%		8.76%	12.72%
	Ending December 31, 2012 (Note 2)				
7	Long-Term Debt	46.51%	5.78%	2.69%	2.70%
8	Preferred Securities	0.92%	8.22%	0.08%	0.08%
9	Preferred Stock	0.24%	6.13%	0.01%	0.02%
10	Preference Stock	2.57%	7.57%	0.19%	0.31%
11	Common Equity	49.76%	11.95%	5.95%	9.75%
12	TOTAL	100.00%		8.92%	12.86%
	Ending December 31, 2013 (Note 3)				
13	Long-Term Debt	46.57%	5.90%	2.75%	2.76%
14	Preferred Securities	0.86%	8.12%	0.07%	0.07%
15	Preferred Stock	0.22%	6.13%	0.01%	0.02%
16	Preference Stock	2.87%	7.80%	0.22%	0.36%
17	Common Equity	49.48%	11.95%	5.91%	9.68%
18	TOTAL	100.00%		8.96%	12.89%

Note 1 - See Exhibit___(APD/RBM-1, Schedule 5, Workpaper 1).
Note 2 - See Exhibit___(APD/RBM-1, Schedule 1, Workpaper 2), Page 5 of 6.
Note 3 - See Exhibit___(APD/RBM-1, Schedule 1, Workpaper 3), Page 5 of 6.

GEORGIA POWER COMPANY

ENVIRONMENTAL INVESTMENT AND EXPENSES
PROJECTED FOR CALENDAR YEARS DECEMBER 2011 - 2013
(Amounts in Thousands)

Line No.	Description	Total Company Less Wholesale	Retail Allocator Note 1	Adjusted Retail
	Ending December 31, 2011			
1	Electric Plant in Service	$ 2,244,652	0.99952	$ 2,243,574
2	Accumulated Depreciation	(193,180)	0.99952	(193,087)
3	Net Plant in Service	$ 2,051,472		$ 2,050,487
4	Accumulated Deferred Income Taxes	(171,245)	0.99959	(171,175)
5	TOTAL RATE BASE	$ 1,880,227		$ 1,879,313
6	Operating Expenses	$ 75,042	0.99951	$ 75,005
7	Environmental Remediation Accrual	9,418	0.99969	9,415
8	Depreciation Expense	83,611	0.99951	83,570
9	Federal Income Taxes (From page 7 of 7)			(66,780)
10	State Income Taxes (From page 7 of 7)			(22,266)
11	EARNINGS AVAILABLE FOR RETURN	$ (168,070)		$ (78,944)
	Ending December 31, 2012			
12	Electric Plant in Service	$ 2,358,875	0.99952	$ 2,357,742
13	Accumulated Depreciation	(268,372)	0.99952	(268,244)
14	Net Plant in Service	$ 2,090,502		$ 2,089,499
15	Accumulated Deferred Income Taxes	(248,059)	0.99959	(247,957)
16	TOTAL RATE BASE	$ 1,842,444		$ 1,841,542
17	Operating Expenses	$ 86,715	0.99951	$ 86,673
18	Environmental Remediation Accrual	9,418	0.99969	9,415
19	Depreciation Expense	85,840	0.99951	85,798
20	Federal Income Taxes (From page 7 of 7)			(71,538)
21	State Income Taxes (From page 7 of 7)			(25,047)
22	EARNINGS AVAILABLE FOR RETURN	$ (181,973)		$ (85,300)
	Ending December 31, 2013			
23	Electric Plant in Service	$ 2,459,917	0.99952	$ 2,458,736
24	Accumulated Depreciation	(351,236)	0.99952	(351,067)
25	Net Plant in Service	$ 2,108,681		$ 2,107,669
26	Accumulated Deferred Income Taxes	(328,889)	0.99959	(328,755)
27	TOTAL RATE BASE	$ 1,779,792		$ 1,778,914
28	Operating Expenses	$ 90,074	0.99951	$ 90,030
29	Environmental Remediation Accrual	9,418	0.99969	9,415
30	Depreciation Expense	87,018	0.99951	86,976
31	Federal Income Taxes (From page 7 of 7)			(70,496)
32	State Income Taxes (From page 7 of 7)			(31,496)
33	EARNINGS AVAILABLE FOR RETURN	$ (186,510)		$ (84,428)

Note 1 From Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1), Pages 4 and 5 of 14.

GEORGIA POWER COMPANY

ENVIRONMENTAL STATE & FEDERAL INCOME TAXES
PROJECTED FOR CALENDAR YEARS 2011 - 2013
(Amounts in Thousands)

Line No.	Description	Twelve Months Ending December 2011	Twelve Months Ending December 2012	Twelve Months Ending December 2013	
1	State Tax Calculation				
2	Operating Expenses	$ 84,420	$ 96,087	$ 99,444	Note 1
3	Depreciation Expense	83,570	85,798	86,976	Note 2
4	Interest Expense	48,298	51,011	50,165	
5	Environmental Expenses Before Taxes	$ 216,288	$ 232,896	$ 236,585	
6	Less:				
7	Non-Deductible Depreciation Expense	3,224	3,455	3,674	
8	Plus:				
9	State Income Tax Deduction	(12,060)	(12,987)	(13,184)	
10	Environmental Expenses Subject to State Tax	$ 201,004	$ 216,454	$ 219,728	
11	State Tax Rate	6.00%	6.00%	6.00%	
12	State Tax on Environmental Expenses	$ (12,060)	$ (12,987)	$ (13,184)	
13	State Tax Credits on Environmental Expenditures	(10,206)	(12,060)	(18,312)	
14	Net State Income Tax - Environmental	$ (22,266)	$ (25,047)	$ (31,496)	
15	Federal Tax Calculation				
16	Environmental Expenses Before Taxes	$ 216,288	$ 232,896	$ 236,585	
17	Less:				
18	Non-Deductible Depreciation Expense	3,224	3,455	$ 3,674	
19	Plus:				
20	State Income Tax Deduction	(12,060)	(12,987)	$ (13,184)	
21	Environmental Expenses Subject to Federal Tax	$ 201,004	$ 216,454	$ 219,727	
22	Federal Tax Rate	35.00%	35.00%	35.00%	
23	Federal Tax on Environmental Expenses	$ (70,352)	$ (75,759)	$ (76,905)	
24	State Tax Credits on Environmental Expenditures	3,572	4,221	6,409	
25	Net Federal Income Tax - Environmental	$ (66,780)	$ (71,538)	$ (70,496)	

Note 1 - From page 6 of 7, including Environmental Remediation Accrual.
Note 2 - From page 6 of 7.

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
PROJECTED CERTIFIED CAPACITY COST RECOVERY (CCCR) INCREASES EFFECTIVE 2011-2013 (Note 1)
(Amounts in Thousands)

Line No.	Description	McDonough Unit 4	McDonough Units 4 & 5	McDonough Units 4 - 6	McDonough Units 4-6 & Mitchell Unit 3	
		McDonough Unit 4 -	McDonough Unit 5 -	McDonough Unit 6 -	Note 2 Mitchell Unit 3 -	
1	Commercial Operation of New Plant	1/1/2012	5/1/2012	1/1/2013	11/1/2013	
2	CCCR Increase Effective	2/1/2012	6/1/2012	2/1/2013	12/1/2013	
3	Electric Plant in Service (Month of Commercial Operation)	Redacted	Redacted	Redacted	Redacted	Note 3
4	Accumulated Depreciation	(109)	(5,935)	(26,997)	(65,259)	Note 4
5	Accumulated Deferred Taxes	2,828	4,523	1,298	(19,744)	Note 5
6	Net Rate Base	Redacted	Redacted	Redacted	Redacted	
7	Revenue Requirement Rate	12.86%	12.86%	12.89%	12.89%	Note 6
8	Revenue Requirement on Net Rate Base	Redacted	Redacted	Redacted	Redacted	
9	Depreciation Expense	Redacted	Redacted	Redacted	Redacted	Note 7
10	**Total CCCR Revenue Requirement**	**$ 99,189**	**$ 176,273**	**$ 251,848**	**$ 262,485**	
11	**CCCR Increases**	**$ 99,189**	**$ 77,084**	**$ 75,575**	**$ 10,637**	

Note 1 - These projections are based on the Company's 2010 Budget. The 2012 and 2013 revenue requirements for the CCCR tariff will be updated through separate compliance filings based on updated revenue forecasts for the upcoming year, and actual financing costs for the previous year. Project costs are subject to review by the Commission through ongoing construction monitoring proceedings. Additional CCCR tariff adjustments may be needed for approximately $16 million in capacity payments associated with a purchase power agreement between the Company and a biomass Qualifying Facility currently scheduled to begin in October 2012 and/or other small renewable projects currently budgeted to go into service in 2012 and 2013 as reflected in Volume 1, Exhibit 3, Supplemental Item S-48. Since construction of these facilities has not yet begun and their ultimate timing is uncertain, no related amounts are reflected herein.

Note 2 - As noted in Docket 31081, the Company plans to propose an amended project plan for the previously certified conversion of Plant Mitchell Unit 3 to biomass. Therefore, the final amount and timing of a CCCR tariff increase related to Mitchell Unit 3 will be dependent on further review and approval of the amended plan by the Commission.

Note 3 - From page 2 of 5.

Note 4 - From page 3 of 5.

Note 5 - From page 4 of 5.

Note 6 - The retail revenue requirement rate will be based on the capital structure and costs approved by the Commission in the Company's most recent Annual Surveillance Report.

Note 7 - From page 5 of 5.

The Trade Secret version of this schedule has been included with all other Trade Secret information in this filing as Supplemental Item S-50 in the Minimum Filing Requirements.

GEORGIA POWER COMPANY

PROJECTED PLANT IN SERVICE BALANCES FOR CERTIFIED CAPACITY PROJECTS BEGINNING COMMERCIAL OPERATION AFTER DECEMBER 31, 2010

(Amounts in Thousands)

Line No.	Description	McDonough Unit 4	McDonough Unit 5	McDonough Unit 6	Mitchell Unit 3
	Projected Plant in Service Balances at Commercial Operation				
1	Planned Commercial Operation Date	1/1/2012	5/1/2012	1/1/2013	11/1/2013
2	Plant McDonough Combined Cycle - Unit 4	Redacted	Redacted	Redacted	Redacted
3	Plant McDonough Combined Cycle - Unit 5	Redacted	Redacted	Redacted	Redacted
4	Plant McDonough Combined Cycle - Unit 6	Redacted	Redacted	Redacted	Redacted
5	Plant McDonough Combined Cycle - Common	Redacted	Redacted	Redacted	Redacted
6	Plant McDonough Combined Cycle -Step Up Substation	Redacted	Redacted	Redacted	Redacted
7	Plant Mitchell Unit 3 Biomass	Redacted	Redacted	Redacted	Redacted
8	TOTAL	Redacted	Redacted	Redacted	Redacted
	Projected Plant in Service Balances Included in CCCR				
9	CCCR Increase Effective	2/1/2012	6/1/2012	2/1/2013	12/1/2013
10	Total McDonough Unit 4 at Commercial Operation	Redacted	Redacted	Redacted	Redacted
11	Post In Service Plant Additions McDonough Unit 4	Redacted	Redacted	Redacted	Redacted
12	Total McDonough Unit 5 at Commercial Operation	Redacted	Redacted	Redacted	Redacted
13	Post In Service Plant Additions McDonough Unit 5	Redacted	Redacted	Redacted	Redacted
14	Total McDonough Unit 6 at Commercial Operation	Redacted	Redacted	Redacted	Redacted
15	PLANT McDONOUGH (ALL RETAIL)	Redacted	Redacted	Redacted	Redacted
16	Retail Allocator	Redacted	Redacted	Redacted	Redacted
17	**PLANT McDONOUGH ADJUSTED RETAIL INCLUDED IN CCCR**	**Redacted**	**Redacted**	**Redacted**	**Redacted**
18	Plant Mitchell Unit 3 Biomass at Commercial Operation				Redacted
19	1 Minus Wholesale Allocator				78.87%
20	PLANT MITCHELL LESS WHOLESALE	$ -	$ -	$ -	Redacted
21	Retail Allocator				0.99952
22	**PLANT MITCHELL ADJUSTED RETAIL INCLUDED IN CCCR**	**$ -**	**$ -**	**$ -**	**Redacted**
23	Transmission System Upgrades related to New Capacity	$ 7,800	$ 7,800	$ 16,800	$ 26,300
24	Retail Allocator	0.99947	0.99947	0.99947	0.99947
25	**TRANS SYSTEM UPGRADES ADJUSTED RETAIL INCLUDED IN CCCR**	**$ 7,796**	**$ 7,796**	**$ 16,791**	**$ 26,286**
26	**TOTAL ADJUSTED RETAIL INCLUDED IN CCCR**	**Redacted**	**Redacted**	**Redacted**	**Redacted**

The Trade Secret version of this schedule has been included with all other Trade Secret information in this filing as Supplemental Item S-50 in the Minimum Filing Requirements.

GEORGIA POWER COMPANY

PROJECTED ACCUMULATED DEPRECIATION BALANCES FOR CERTIFIED CAPACITY PROJECTS BEGINNING COMMERCIAL OPERATION AFTER DECEMBER 31, 2010

(Amounts in Thousands)

Line No.	Description	Increase Effective 2/1/2012	Increase Effective 6/1/2012	Increase Effective 2/1/2013	Increase Effective 12/1/2013
	Projected Accumulated Depreciation Balances Included in CCCR				
1	Cumulative Balance Plant McDonough Unit 4	$ (2)	$ (5,770)	$ (17,372)	$ (31,880)
2	Cumulative Balance Plant McDonough Unit 5			(9,279)	(20,880)
3	Cumulative Balance Plant McDonough Unit 6				(11,590)
4	PLANT McDONOUGH (ALL RETAIL)	$ (2)	$ (5,770)	$ (26,651)	$ (64,350)
5	Retail Allocator	0.99952	0.99952	0.99952	0.99952
6	PLANT McDONOUGH ADJUSTED RETAIL INCLUDED IN CCCR	$ (2)	$ (5,768)	$ (26,638)	$ (64,320)
7	Cumulative Balance Plant Mitchell Unit 3 Biomass				$ (180)
8	1 Minus Wholesale Allocator				78.87%
9	PLANT MITCHELL LESS WHOLESALE	$ -	$ -	$ -	$ (142)
10	Retail Allocator				0.99952
11	PLANT MITCHELL ADJUSTED RETAIL INCLUDED IN CCCR	$ -	$ -	$ -	$ (142)
12	Transmission System Upgrades related to New Capacity	$ (106)	$ (167)	$ (359)	$ (798)
13	Retail Allocator	0.99946	0.99946	0.99946	0.99946
14	TRANS SYSTEM UPGRADES ADJUSTED RETAIL INCLUDED IN CCCR	$ (106)	$ (167)	$ (359)	$ (798)
15	**TOTAL ADJUSTED RETAIL INCLUDED IN CCCR**	**$ (109)**	**$ (5,935)**	**$ (26,997)**	**$ (65,259)**

GEORGIA POWER COMPANY

PROJECTED ACCUMULATED DEFERRED INCOME TAX BALANCES FOR CERTIFIED CAPACITY PROJECTS BEGINNING COMMERCIAL OPERATION AFTER DECEMBER 31, 2010

(Amounts in Thousands)

Line No.	Description	Increase Effective 2/1/2012	Increase Effective 6/1/2012	Increase Effective 2/1/2013	Increase Effective 12/1/2013
	Projected Accumulated Deferred Income Tax Balances Included in CCCR				
1	Cumulative Balance Plant McDonough Unit 4	$ 2,876	$ 1,825	$ (527)	$ (7,152)
2	Cumulative Balance Plant McDonough Unit 5		2,774	605	(6,024)
3	Cumulative Balance Plant McDonough Unit 6			1,379	(5,223)
4	PLANT McDONOUGH (ALL RETAIL)	$ 2,876	$ 4,599	$ 1,456	$ (18,398)
5	Retail Allocator	0.99959	0.99959	0.99959	0.99959
6	PLANT McDONOUGH ADJUSTED RETAIL INCLUDED IN CCCR	$ 2,874	$ 4,597	$ 1,456	$ (18,391)
7	Cumulative Balance Plant Mitchell Unit 3 Biomass				$ (1,272)
8	1 Minus Wholesale Allocator				78.87%
9	PLANT MITCHELL LESS WHOLESALE	$ -	$ -	$ -	$ (1,003)
10	Retail Allocator				0.99959
11	PLANT MITCHELL ADJUSTED RETAIL INCLUDED IN CCCR	$ -	$ -	$ -	$ (1,003)
12	Transmission System Upgrades related to New Capacity	$ (47)	$ (74)	$ (158)	$ (351)
13	Retail Allocator	0.99959	0.99959	0.99959	0.99959
14	TRANS SYSTEM UPGRADES ADJUSTED RETAIL INCLUDED IN CCCR	$ (47)	$ (74)	$ (158)	$ (351)
15	**TOTAL ADJUSTED RETAIL INCLUDED IN CCCR**	**$ 2,828**	**$ 4,523**	**$ 1,298**	**$ (19,744)**

GEORGIA POWER COMPANY

**PROJECTED DEPRECIATION EXPENSE FOR
CERTIFIED CAPACITY PROJECTS BEGINNING
COMMERCIAL OPERATION AFTER DECEMBER 31, 2010**

(Amounts in Thousands)

Line No.	Description	Increase Effective 2/1/2012	Increase Effective 6/1/2012	Increase Effective 2/1/2013	Increase Effective 12/1/2013		
					Plant McDonough	Plant Mitchell	Total
	Projected Depreciation Expense Included in CCCR						
1	CCCR Plant in Service (excl Trans System Upgrades from Page 2 of 5)	Redacted	Redacted	Redacted	Redacted	Redacted	
2	Less Land	Redacted	Redacted	Redacted	Redacted	Redacted	
3	Depreciable CCCR Plant in Service	Redacted	Redacted	Redacted	Redacted	Redacted	
4	Composite Depreciation Rate	Redacted	Redacted	Redacted	Redacted	Redacted	
5	Annualized Book Depreciation Expense	Redacted	Redacted	Redacted	Redacted	Redacted	
6	Less Non Deductible Book Depreciation (NDBD) (3% of Annual Book Deprec Expense)	518	940	1,358	1,358	131	
7	Annualized Book Depreciation Expense Subject to Federal & State Income Taxes	Redacted	Redacted	Redacted	Redacted	Redacted	
8	Federal & State Income Taxes (at 38.679%)	Redacted	Redacted	Redacted	Redacted	Redacted	
9	Annualized Book Depreciation Expense Before Income Taxes (Line 5)	Redacted	Redacted	Redacted	Redacted	Redacted	
10	Less Federal & State Income Taxes at 38.679% (Line 8)	Redacted	Redacted	Redacted	Redacted	Redacted	
11	Annualized Book Depreciation Expense After Income Taxes	Redacted	Redacted	Redacted	Redacted	Redacted	
12	Income Expansion Factor	0.61055	0.61055	0.61059	0.61059	0.61059	
13	TOTAL	Redacted	Redacted	Redacted	Redacted	Redacted	
14	1 Minus Wholesale Allocator	100.00%	100.00%	100.00%	100.00%	78.87%	
15	TOTAL LESS WHOLESALE	Redacted	Redacted	Redacted	Redacted	Redacted	
16	Retail Allocator	0.99951	0.99951	0.99951	0.99951	0.99951	
17	**PRODUCTION PLANT INCLUDED IN CCCR**	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted
18	Depreciable CCCR Plant in Service (Trans System Upgrades from Page 2 of 5)	$ 7,800	$ 7,800	$ 16,800	$ 26,300		
19	Composite Depreciation Rate	2.34%	2.34%	2.34%	2.34%		
20	Annualized Book Depreciation Expense	$ 183	$ 183	$ 393	$ 615		
21	Less Federal & State Income Taxes at 38.679%	71	71	152	238		
22	Annualized Book Depreciation Expense After Income Taxes	$ 112	$ 112	$ 241	$ 377		
23	Income Expansion Factor	0.61055	0.61055	0.61059	0.61059		
24	Subtotal	$ 183	$ 183	$ 395	$ 618		
25	Retail Allocator	0.99948	0.99948	0.99948	0.99948		
26	**TRANS SYSTEM UPGRADES INCLUDED IN CCCR**	**$ 183**	**$ 183**	**$ 395**	**$ 618**		**$ 618**
27	**TOTAL ADJUSTED RETAIL INCLUDED IN CCCR**	**Redacted**	**Redacted**	**Redacted**	**Redacted**	**Redacted**	**Redacted**

The Trade Secret version of this schedule has been included with all other Trade Secret information in this filing as Supplemental Item S-50 in the Minimum Filing Requirements.

TRADE SECRET

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
PROJECTED CERTIFIED CAPACITY COST RECOVERY (CCCR) INCREASES EFFECTIVE 2011-2013 (Note 1)
(Amounts in Thousands)

Line No.	Description	McDonough Unit 4	McDonough Units 4 & 5	McDonough Units 4 - 6	McDonough Units 4-6 & Mitchell Unit 3	
		McDonough Unit 4 -	McDonough Unit 5 -	McDonough Unit 6 -	Note 2 Mitchell Unit 3 -	
1	Commercial Operation of New Plant	1/1/2012	5/1/2012	1/1/2013	11/1/2013	
2	CCCR Increase Effective	2/1/2012	6/1/2012	2/1/2013	12/1/2013	
3	Electric Plant in Service (Month of Commercial Operation)	$ 629,892	$ 1,121,541	$ 1,617,376	$ 1,730,162	Note 3
4	Accumulated Depreciation	(109)	(5,935)	(26,997)	(65,259)	Note 4
5	Accumulated Deferred Taxes	2,828	4,523	1,298	(19,744)	Note 5
6	Net Rate Base	$ 632,611	$ 1,120,129	$ 1,591,677	$ 1,645,159	
7	Revenue Requirement Rate	12.86%	12.86%	12.89%	12.89%	Note 6
8	Revenue Requirement on Net Rate Base	$ 81,354	$ 144,049	$ 205,167	$ 212,061	
9	Depreciation Expense	17,835	32,225	46,681	50,424	Note 7
10	**Total CCCR Revenue Requirement**	**$ 99,189**	**$ 176,273**	**$ 251,848**	**$ 262,485**	
11	**CCCR Increases**	**$ 99,189**	**$ 77,084**	**$ 75,575**	**$ 10,637**	

Note 1 - These projections are based on the Company's 2010 Budget. The 2012 and 2013 revenue requirements for the CCCR tariff will be updated through separate compliance filings based on updated revenue forecasts for the upcoming year, and actual financing costs for the previous year. Project costs are subject to review by the Commission through ongoing construction monitoring proceedings. Additional CCCR tariff adjustments may be needed for approximately $16 million in capacity payments associated with a purchase power agreement between the Company and a biomass Qualifying Facility currently scheduled to begin in October 2012 and/or other small renewable projects currently budgeted to go into service in 2012 and 2013 as reflected in Volume 1, Exhibit 3, Supplemental Item S-48. Since construction of these facilities has not yet begun and their ultimate timing is uncertain, no related amounts are reflected herein.

Note 2 - As noted in Docket 31081, the Company plans to propose an amended project plan for the previously certified conversion of Plant Mitchell Unit 3 to biomass. Therefore, the final amount and timing of a CCCR tariff increase related to Mitchell Unit 3 will be dependent on further review and approval of the amended plan by the Commission.

Note 3 - From page 2 of 5.

Note 4 - From page 3 of 5.

Note 5 - From page 4 of 5.

Note 6 - The retail revenue requirement rate will be based on the capital structure and costs approved by the Commission in the Company's most recent Annual Surveillance Report.

Note 7 - From page 5 of 5.

TRADE SECRET

GEORGIA POWER COMPANY

PROJECTED PLANT IN SERVICE BALANCES FOR CERTIFIED CAPACITY PROJECTS BEGINNING COMMERCIAL OPERATION AFTER DECEMBER 31, 2010

(Amounts in Thousands)

Line No.	Description	McDonough Unit 4	McDonough Unit 5	McDonough Unit 6	Mitchell Unit 3
	Projected Plant in Service Balances at Commercial Operation				
1	Planned Commercial Operation Date	1/1/2012	5/1/2012	1/1/2013	11/1/2013
2	Plant McDonough Combined Cycle - Unit 4	$ 536,324	$ -	$ -	$ -
3	Plant McDonough Combined Cycle - Unit 5	-	486,518	-	-
4	Plant McDonough Combined Cycle - Unit 6	-	-	486,310	-
5	Plant McDonough Combined Cycle - Common	83,026	5,235	432	-
6	Plant McDonough Combined Cycle -Step Up Substation	3,046	-	-	-
7	Plant Mitchell Unit 3 Biomass				131,027
8	TOTAL	$ 622,395	$ 491,753	$ 486,742	$ 131,027
	Projected Plant in Service Balances Included in CCCR				
9	CCCR Increase Effective	2/1/2012	6/1/2012	2/1/2013	12/1/2013
10	Total McDonough Unit 4 at Commercial Operation	$ 622,395	$ 622,395	$ 622,395	$ 622,395
11	Post In Service Plant Additions McDonough Unit 4		132	219	219
12	Total McDonough Unit 5 at Commercial Operation		491,753	491,753	491,753
13	Post In Service Plant Additions McDonough Unit 5			245	245
14	Total McDonough Unit 6 at Commercial Operation			486,742	486,742
15	PLANT McDONOUGH (ALL RETAIL)	$ 622,395	#########	#########	$ 1,601,354
16	Retail Allocator	0.99952	0.99952	0.99952	0.99952
17	**PLANT McDONOUGH ADJUSTED RETAIL INCLUDED IN CCCR**	**$ 622,096**	#########	#########	**$ 1,600,585**
18	Plant Mitchell Unit 3 Biomass at Commercial Operation				$ 131,027
19	1 Minus Wholesale Allocator				78.87%
20	PLANT MITCHELL LESS WHOLESALE	$ -	$ -	$ -	$ 103,341
21	Retail Allocator				0.99952
22	**PLANT MITCHELL ADJUSTED RETAIL INCLUDED IN CCCR**	**$ -**	**$ -**	**$ -**	**$ 103,291**
23	Transmission System Upgrades related to New Capacity	$ 7,800	$ 7,800	$ 16,800	$ 26,300
24	Retail Allocator	0.99947	0.99947	0.99947	0.99947
25	**TRANS SYSTEM UPGRADES ADJUSTED RETAIL INCLUDED IN CCCR**	**$ 7,796**	**$ 7,796**	**$ 16,791**	**$ 26,286**
26	**TOTAL ADJUSTED RETAIL INCLUDED IN CCCR**	**$ 629,892**	#########	#########	**$ 1,730,162**

TRADE SECRET

GEORGIA POWER COMPANY

PROJECTED DEPRECIATION EXPENSE FOR CERTIFIED CAPACITY PROJECTS BEGINNING COMMERCIAL OPERATION AFTER DECEMBER 31, 2010

(Amounts in Thousands)

Line No.	Description	Increase Effective 2/1/2012	Increase Effective 6/1/2012	Increase Effective 2/1/2013	Increase Effective 12/1/2013		
					Plant McDonough	Plant Mitchell	Total
	Projected Depreciation Expense Included in CCCR						
1	CCCR Plant in Service (excl Trans System Upgrades from Page 2 of 5)	$622,395	$1,114,280	$1,601,354	$1,601,354	$ 131,027	
2	Less Land	(19,000)	(19,000)	(19,000)	(19,000)	(120)	
3	Depreciable CCCR Plant in Service	$603,395	$1,095,280	$1,582,354	$1,582,354	$ 130,907	
4	Composite Depreciation Rate	2.86%	2.86%	2.86%	2.86%	3.33%	
5	Annualized Book Depreciation Expense	$ 17,257	$ 31,325	$ 45,255	$ 45,255	$ 4,364	
6	Less Non Deductible Book Depreciation (NDBD) (3% of Annual Book Deprec Expense)	518	940	1,358	1,358	131	
7	Annualized Book Depreciation Expense Subject to Federal & State Income Taxes	$ 16,739	$ 30,385	$ 43,898	$ 43,898	$ 4,233	
8	Federal & State Income Taxes (at 38.679%)	$ 6,475	$ 11,753	$ 16,979	$ 16,979	$ 1,637	
9	Annualized Book Depreciation Expense Before Income Taxes (Line 5)	$ 17,257	$ 31,325	$ 45,255	$ 45,255	$ 4,364	
10	Less Federal & State Income Taxes at 38.679% (Line 8)	6,475	11,753	16,979	16,979	1,637	
11	Annualized Book Depreciation Expense After Income Taxes	$ 10,782	$ 19,572	$ 28,276	$ 28,276	$ 2,726	
12	Income Expansion Factor	0.61055	0.61055	0.61059	0.61059	0.61059	
13	TOTAL	$ 17,660	$ 32,057	$ 46,309	$ 46,309	$ 4,465	
14	1 Minus Wholesale Allocator	100.00%	100.00%	100.00%	100.00%	78.87%	
15	TOTAL LESS WHOLESALE	$ 17,660	$ 32,057	$ 46,309	$ 46,309	$ 3,522	
16	Retail Allocator	0.99951	0.99951	0.99951	0.99951	0.99951	
17	**PRODUCTION PLANT INCLUDED IN CCCR**	**$ 17,652**	**$ 32,041**	**$ 46,286**	**$ 46,286**	**$ 3,520**	**$49,806**
18	Depreciable CCCR Plant in Service (Trans System Upgrades from Page 2 of 5)	$ 7,800	$ 7,800	$ 16,800	$ 26,300		
19	Composite Depreciation Rate	2.34%	2.34%	2.34%	2.34%		
20	Annualized Book Depreciation Expense	$ 183	$ 183	$ 393	$ 615		
21	Less Federal & State Income Taxes at 38.679%	71	71	152	238		
22	Annualized Book Depreciation Expense After Income Taxes	$ 112	$ 112	$ 241	$ 377		
23	Income Expansion Factor	0.61055	0.61055	0.61059	0.61059		
24	Subtotal	$ 183	$ 183	$ 395	$ 618		
25	Retail Allocator	0.99948	0.99948	0.99948	0.99948		
26	**TRANS SYSTEM UPGRADES INCLUDED IN CCCR**	**$ 183**	**$ 183**	**$ 395**	**$ 618**		**$ 618**
27	**TOTAL ADJUSTED RETAIL INCLUDED IN CCCR**	**$ 17,835**	**$ 32,225**	**$ 46,681**	**$ 46,904**	**$ 3,520**	**$50,424**

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
2011, 2012 and 2013 Demand Side Management (DSM) Tariffs

Line No.	Description	2011	2012 (a)	2013 (a)
1	**Residential Programs**			
2	Incentive Costs	2,668,372	4,939,903	8,520,343
3	Non-Incentive Costs	5,123,960	7,164,357	8,603,230
4	Cross-Cutting Costs	450,000	300,000	300,000
5	Additional Sum	0	1,290,441	5,137,419
6	Previously-Certified Program Costs & Other DSM	16,150,000	16,150,000	16,150,000
7	***Residential Sub-total***	24,392,332	29,844,701	38,710,991
8	**Commercial Programs**			
9	Incentive Costs	2,328,460	4,710,417	5,855,306
10	Non-Incentive Costs	2,723,200	3,736,343	4,205,844
11	Cross-Cutting Costs	450,000	300,000	300,000
12	Additional Sum	0	8,189,864	15,761,321
13	***Commercial Sub-total***	5,501,660	16,936,624	26,122,471
14	***Total DSM Tariff Costs***	**29,893,993**	**46,781,325**	**64,833,463**
15	Amort of DSM Deferred Asset - FERC 407	2,972,658	2,972,658	2,972,658
16	Carrying Costs on Deferred Asset	1,038,848	816,591	583,279
17	***DSM Tariff - Ancillary Impact Costs***	4,011,506	3,789,249	3,555,937
18	***Total DSM Tariff Costs***	**33,905,499**	**50,570,574**	**68,389,400**
19	*Federal and State Income Taxes*	13,114,308	19,560,192	26,452,336
20	*DSM Cost Tariff Costs After Tax*	20,791,191	31,010,382	41,937,064
21	*Income Expansion Factor*	0.61049	0.61055	0.61059
22	***DSM Tariff Revenue Requirement***	**34,056,454**	**50,791,272**	**68,682,293**
23	***DSM Revenues Included in current Tariffs***	**(2,402,928)**	**(2,402,928)**	**(2,402,928)**
24	***Total DSM Tariff Revenue Requirement***	**31,653,526**	**48,388,344**	**66,279,365**
25	***DSM Tariff Increases***	31,653,526	16,734,819	17,891,021

(a) Revenue requirements for 2012 and 2013 will be updated through separate annual compliance filings.

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
2011, 2012 and 2013 DSM Incentive and Program Cost Detail

Line No.	Description	2011	2012	2013
1	***Incentives Paid:***			
2	**Residential Programs**			
3	Residential Lighting & Appliances	214,500	891,225	1,980,420
4	Residential Existing Homes	601,742	1,222,720	2,784,433
5	Residential High Efficiency New Homes	1,552,500	2,384,996	3,169,024
6	Residential Refrigerator Recycling	259,630	395,287	534,955
7	Residential Water Heating	40,000	45,675	51,511
8	*Residential Sub-total*	*2,668,372*	*4,939,903*	*8,520,343*
9	**Commercial Programs**			
10	Commercial Custom Incentive	1,300,251	2,118,745	2,710,129
11	Commercial Prescriptive Incentive	1,028,210	2,591,672	3,145,178
12	*Commercial Sub-total*	*2,328,460*	*4,710,417*	*5,855,306*
13	***TOTAL***	**4,996,832**	**9,650,320**	**14,375,649**
14	***Program Costs:***			
15	**Residential Programs**			
16	Residential Lighting & Appliances	982,084	1,277,454	1,451,957
17	Residential Existing Homes	1,669,856	2,479,619	2,990,836
18	Residential High Efficiency New Homes	1,085,945	1,364,022	1,483,351
19	Residential Refrigerator Recycling	1,184,797	1,883,381	2,437,414
20	Residential Water Heating	201,278	159,880	239,671
21	*Residential Sub-total*	*5,123,960*	*7,164,357*	*8,603,230*
22	**Commercial Programs**			
23	Commercial Custom Incentive	751,900	1,073,323	1,252,407
24	Commercial Prescriptive Incentive	1,971,300	2,663,019	2,953,437
25	*Commercial Sub-total*	*2,723,200*	*3,736,343*	*4,205,844*
26	**Cross-Cutting Program Costs**			
27	Program Management Oversight	300,000	300,000	300,000
28	Program Tracking Database	400,000	150,000	150,000
29	Outreach/Education/Training	200,000	150,000	150,000
30	*Cross-Cutting Sub-total*	*900,000*	*600,000*	*600,000*
31	***Total***	**8,747,160**	**11,500,700**	**13,409,074**
32	***Total Incentive and Program Costs:***			
33	Residential Programs	8,242,332	12,404,260	17,423,572
34	Commercial Programs	5,501,660	8,746,759	10,361,150
35	***Total***	**13,743,993**	**21,151,020**	**27,784,723**

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
2011, 2012 and 2013 DSM Previously Certified Costs

Line No.	Description	2011	2012	2013
1	Residential Power Credits - Single Family	7,000,000	7,000,000	7,000,000
2	Residential Power Credits - Multi Family	2,500,000	2,500,000	2,500,000
3	Residential Weatherization Assistance for Low Income	2,000,000	2,000,000	2,000,000
4	Residential Energy Efficiency (EE) Info	250,000	250,000	250,000
5	Residential EE Consumer Awareness Campaign	4,400,000	4,400,000	4,400,000
6	***Total***	**16,150,000**	**16,150,000**	**16,150,000**

* Note: In the planning phase for Power Credit, the program was designed to break even (costs equal benefits); therefore, there is no additional sum calculated at this time. In any given year, this may vary and any change will be included in future true-ups.

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
2011, 2012 and 2013 DSM Additional Sum Calculation

Line No.	Description	2011	2012 (a)	2013 (a)
1	**Residential**			
2	Electric Avoided Costs	19,434,396	38,213,076	68,797,762
3	Program Incentive Costs	2,668,372	4,939,903	8,520,343
4	Program Non-Incentive Costs	5,123,960	7,164,357	8,603,230
5	Cross Cutting Costs	450,000	300,000	300,000
6	Total Program Costs	8,242,332	12,404,260	17,423,572
7	***Additional Sum***	***-***	***1,290,441***	***5,137,419***
8	**Commercial**			
9	Electric Avoided Costs	85,788,952	172,544,049	221,976,071
10	Program Incentive Costs	2,328,460	4,710,417	5,855,306
11	Program Non-Incentive Costs	2,723,200	3,736,343	4,205,844
12	Cross Cutting Costs	450,000	300,000	300,000
13	Total Program Costs	5,501,660	8,746,759	10,361,150
14	***Additional Sum***	***-***	***8,189,864***	***15,761,321***
15	**Total**			
16	Electric Avoided Costs	105,223,348	210,757,125	290,773,834
17	Program Incentive Costs	4,996,832	9,650,320	14,375,649
18	Program Non-Incentive Costs	7,847,160	10,900,700	12,809,074
19	Cross Cutting Costs	900,000	600,000	600,000
20	Total Program Costs	13,743,993	21,151,020	27,784,723
21	***Total Additional Sum***	***-***	***9,480,305***	***20,898,740***

(a) Revenue requirements for 2012 and 2013 will be updated through separate annual compliance filings.

GEORGIA POWER COMPANY

ADJUSTED RETAIL RATE OF RETURN SUMMARY
ESTIMATED AVERAGE FOR THE THIRTEEN MONTHS ENDING DECEMBER 31, 20
(Amounts in Thousands)

LINE NO.	COMPONENT	AVERAGE ADJUSTED BALANCE 12/31/11 (a)	AVERAGE COST (b)	AVERAGE COMPONENT COST
(1)	(2)	(3)	(4)	(5)
1	Long-Term Debt	$8,057,327	5.38%	2.49%
2	Preferred Securities	$171,039	8.32%	0.08%
3	Preferred Stock	$45,000	6.13%	0.02%
4	Preference Stock	$378,846	7.13%	0.15%
5	Common Equity	$8,792,724	11.95%	6.02%
6	TOTAL	$17,444,936		8.76%

(a) Refer to Workpaper 2 of this schedule for the calculation of retail capital components.
(b) Refer to Workpaper 3 of this schedule for the calculation of retail cost components.

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

CAPITAL STRUCTURE - FORECAST
ESTIMATED FOR THE THIRTEEN MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

	Projected Dec-10	Projected Jan-11	Projected Feb-11	Projected Mar-11	Projected Apr-11	Projected May-11	Projected Jun-11
First Mortgage Bonds	$0	$0	$0	$0	$0	$0	$0
Less: Unamort. Loss on Reaq. Debt	(48,632)	(48,203)	(47,774)	(47,346)	(46,919)	(46,491)	(46,063)
Plus: Unamort. Gain on Reaq. Debt	312	310	308	306	304	302	300
Less: Unamort. Issuance Exp.	0	0	0	0	0	0	0
Less: Unamort. Disc.	0	0	0	0	0	0	0
Sub-Total	($48,320)	($47,893)	($47,466)	($47,040)	($46,614)	($46,189)	($45,763)
Pollution Control Bonds	$2,035,525	$2,035,525	$2,035,525	$2,035,525	$2,035,525	$2,035,525	$2,035,525
Less: Unamort. Loss on Reaq. Debt	(54,730)	(54,388)	(54,045)	(53,703)	(53,360)	(53,017)	(52,675)
Less: Unamort. Issuance Exp.	(24,278)	(24,173)	(24,068)	(23,963)	(23,858)	(23,753)	(23,649)
Less: Unamort. Disc.	(2,840)	(2,830)	(2,820)	(2,809)	(2,799)	(2,789)	(2,779)
Less: Unamort. Insurance Premium	0	0	0	0	0	0	0
Sub-Total	$1,953,677	$1,954,134	$1,954,592	$1,955,050	$1,955,507	$1,955,965	$1,956,423
Senior Notes	$5,889,289	$5,789,289	$5,789,289	$6,389,289	$6,389,289	$6,389,289	$6,389,289
Less: Unamort. Issuance Exp.	(98,131)	(97,355)	(96,592)	(107,829)	(106,747)	(105,666)	(104,584)
Less: Unamort. Loss on Reaq. Debt	(4,307)	(4,277)	(4,247)	(4,217)	(4,187)	(4,157)	(4,127)
Less: Unamort. Insurance Premium	(10,041)	(9,988)	(9,935)	(9,882)	(9,829)	(9,775)	(9,722)
Sub-Total	$5,776,809	$5,677,669	$5,678,515	$6,267,362	$6,268,526	$6,269,691	$6,270,856
Total Long-Term Debt	**$7,682,166**	**$7,583,910**	**$7,585,642**	**$8,175,371**	**$8,177,419**	**$8,179,467**	**$8,181,515**
Preferred Securities	$206,186	$206,186	$206,186	$206,186	$206,186	$206,186	$206,186
Less: Unamort. Loss on Reacq. Debt	(31,056)	(30,876)	(30,696)	(30,516)	(30,336)	(30,156)	(29,976)
Less: Unamortized Issuance Exp.	(5,251)	(5,237)	(5,224)	(5,211)	(5,198)	(5,184)	(5,171)
Total Preferred Securities	**$169,879**	**$170,072**	**$170,265**	**$170,459**	**$170,652**	**$170,845**	**$171,038**
Total Preferred Stock	**$45,000**	**$45,000**	**$45,000**	**$45,000**	**$45,000**	**$45,000**	**$45,000**
Total Preference Stock	**$325,000**	**$325,000**	**$325,000**	**$325,000**	**$325,000**	**$325,000**	**$425,000**

Common Equity	$8,563,245	$8,374,421	$8,387,564	$8,682,108	$8,450,292	$8,483,545	$8,877,231
Plus: Other Comprehensive Income	20,442	20,190	19,938	19,686	19,435	19,183	18,931
Total Common Equity	**$8,583,687**	**$8,394,611**	**$8,407,502**	**$8,701,794**	**$8,469,726**	**$8,502,728**	**$8,896,162**
TOTAL CAPITALIZATION	**$16,805,732**	**$16,518,593**	**$16,533,409**	**$17,417,624**	**$17,187,798**	**$17,223,040**	**$17,718,716**
	Projected	Projected	Projected	Projected	Projected	Projected	**13 Month**

	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	**Average**
First Mortgage Bonds	$0	$0	$0	$0	$0	$0	$0
Less: Unamort. Loss on Reaq. Debt	(45,636)	(45,208)	(44,780)	(44,353)	(43,925)	(43,497)	(46,064)
Plus: Unamort. Gain on Reaq. Debt	298	296	294	292	290	288	300
Less: Unamort. Issuance Exp.	0	0	0	0	0	0	0
Less: Unamort. Disc.	0	0	0	0	0	0	0
Sub-Total	($45,337)	($44,912)	($44,486)	($44,060)	($43,635)	($43,209)	($45,764)
Pollution Control Bonds	$2,027,195	$2,027,195	$2,027,195	$2,027,195	$2,027,195	$2,027,195	$2,031,680
Less: Unamort. Loss on Reaq. Debt	(52,333)	(51,992)	(51,651)	(51,309)	(50,968)	(50,627)	(52,677)
Less: Unamort. Issuance Exp.	(23,545)	(23,442)	(23,338)	(23,235)	(23,131)	(23,028)	(23,651)
Less: Unamort. Disc.	(2,769)	(2,759)	(2,749)	(2,738)	(2,728)	(2,718)	(2,779)
Less: Unamort. Insurance Premium	0	0	0	0	0	0	0
Sub-Total	$1,948,548	$1,949,003	$1,949,458	$1,949,912	$1,950,367	$1,950,822	$1,952,573
Senior Notes	$6,389,289	$6,389,289	$6,389,289	$6,389,289	$6,389,289	$6,489,289	$6,266,212
Less: Unamort. Issuance Exp.	(103,503)	(102,421)	(101,339)	(100,258)	(99,176)	(100,095)	(101,823)
Less: Unamort. Loss on Reaq. Debt	(4,097)	(4,067)	(4,037)	(4,007)	(3,977)	(3,947)	(4,127)
Less: Unamort. Insurance Premium	(9,682)	(9,643)	(9,603)	(9,563)	(9,524)	(9,484)	(9,744)
Sub-Total	$6,272,007	$6,273,158	$6,274,309	$6,275,461	$6,276,612	$6,375,763	$6,150,518
Total Long-Term Debt	**$8,175,218**	**$8,177,249**	**$8,179,281**	**$8,181,313**	**$8,183,344**	**$8,283,376**	**$8,057,327**
Preferred Securities	$206,186	$206,186	$206,186	$206,186	$206,186	$206,186	$206,186
Less: Unamort. Loss on Reacq. Debt	(29,796)	(29,616)	(29,437)	(29,257)	(29,077)	(28,897)	(29,976)
Less: Unamortized Issuance Exp.	(5,158)	(5,144)	(5,131)	(5,118)	(5,105)	(5,091)	(5,171)
Total Preferred Securities	**$171,231**	**$171,425**	**$171,618**	**$171,811**	**$172,004**	**$172,197**	**$171,039**
Total Preferred Stock	**$45,000**	**$45,000**	**$45,000**	**$45,000**	**$45,000**	**$45,000**	**$45,000**
Total Preference Stock	**$425,000**	**$425,000**	**$425,000**	**$425,000**	**$425,000**	**$425,000**	**$378,846**
Common Equity	$8,792,204	$8,935,647	$9,291,088	$9,067,241	$9,062,457	$9,092,271	$8,773,793
Plus: Other Comprehensive Income	18,679	18,427	18,176	17,924	17,672	17,420	18,931
Total Common Equity	**$8,810,883**	**$8,954,075**	**$9,309,264**	**$9,085,165**	**$9,080,129**	**$9,109,692**	**$8,792,724**
TOTAL CAPITALIZATION	**$17,627,332**	**$17,772,748**	**$18,130,163**	**$17,908,288**	**$17,905,477**	**$18,035,265**	**$17,444,936**

GEORGIA POWER COMPANY

COST OF DEBT, PREFERRED SECURITIES AND PREFERRED AND PREFERENCE STOCK
ESTIMATED FOR THE THIRTEEN MONTHS ENDING DECEMBER 31, 2011

	Debt	Preferred Securities	Preferred Stock	Preference Stock
Dec-10	5.22%	8.37%	6.13%	6.91%
Jan-11	5.31%	8.36%	6.13%	6.91%
Feb-11	5.31%	8.35%	6.13%	6.91%
Mar-11	5.24%	8.34%	6.13%	6.91%
Apr-11	5.34%	8.34%	6.13%	6.91%
May-11	5.34%	8.33%	6.13%	6.91%
Jun-11	5.34%	8.32%	6.13%	7.32%
Jul-11	5.44%	8.31%	6.13%	7.32%
Aug-11	5.44%	8.30%	6.13%	7.32%
Sep-11	5.44%	8.29%	6.13%	7.32%
Oct-11	5.51%	8.28%	6.13%	7.32%
Nov-11	5.51%	8.28%	6.13%	7.32%
Dec-11	5.53%	8.27%	6.13%	7.32%
13 Month Average	5.38%	8.32%	6.13%	7.13%

GEORGIA POWER COMPANY

ADJUSTED RETAIL RATE OF RETURN SUMMARY
ESTIMATED AS OF DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	COMPONENT	END-OF-PERIOD ADJUSTED BALANCE 12/31/11 (a)	COST	COMPONENT COST
(1)	(2)	(3)	(4)	(5)
1	Long-Term Debt	$8,283,376	5.53%	2.54%
2	Preferred Securities	$172,198	8.27%	0.08%
3	Preferred Stock	$45,000	6.13%	0.02%
4	Preference Stock	$425,000	7.32%	0.17%
5	Common Equity	$9,109,692	11.95%	6.04%
6	TOTAL	$18,035,265		8.85%

(a) Refer to Workpaper 2 of this schedule for the calculation of retail capital components.

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

CALCULATION OF RETAIL CAPITAL COMPONENTS
ESTIMATED AS OF DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	COMPONENT	BALANCE PER BOOKS 12/31/11	PERCENT	GPSC RETAIL ADJUSTMENTS		ADJUSTED BALANCE 12/31/11
(1)	(2)	(3)	(4)	(5)		(6)
1	Capitalized Lease	$48,300	0.25%	($48,300)	(a)	$0
2	Short-Term Debt	$610,232	3.22%	($610,232)	(b)	$0
3	Long-Term Debt	$8,516,484	44.96%	($233,108)	(c)	$8,283,376
4	Preferred Securities	$206,186	1.09%	($33,988)	(d)	$172,198
5	Preferred Stock	$45,000	0.24%	$0		$45,000
6	Preference Stock	$425,000	2.24%	$0		$425,000
7	Common Equity	$9,092,271	48.00%	$17,420	(e)	$9,109,692
7	TOTAL	$18,943,473	100.00%	($908,208)		$18,035,265

(a) Per Docket No. 3270, the lease on the 241 Ralph McGill building is treated as an operating lease for retail ratemaking.

(b) Short-term debt excluded as it funds Under-Recovered Fuel Expense and CWIP which are not included in rate base.

(c)

Unamortized Debt Discount and Premium (Net)	($6,665)
Unamortized Debt Issuance Expense	(123,123)
Unamortized Gain on Reacquired Debt	288
Unamortized Loss on Reacquired Debt	(103,608)
Unamortized Insurance Premium	0
Total	(233,108)

(d)

Unamortized Debt Issuance Expense	($5,091)
Unamortized Loss on Reacquired Debt	(28,897)
Total	($33,988)

(e) ASC 815 - Mark-to-Market Interest Rate Hedges 17,420

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

RETAIL RATE OF RETURN
COST OF LONG-TERM DEBT
ESTIMATED AS OF DECEMBER 31, 2011

LINE NO.	DESCRIPTION	COST	AMOUNT OUTSTANDING	ANNUALIZED COST
(1)	(2)	(3)	(4)	(5)
1	First Mortgage Bonds, Pollution Control Bonds and Senior Notes	5.53%	$8,283,376 (a)	$458,071

(a)	Pollution Control Bonds and Senior Notes Outstanding	$8,516,484
	Unamortized Debt Discount and Premium (Net)	(6,665)
	Unamortized Debt Issuance Expense	(123,123)
	Unamortized Gain on Reacquired Debt	288
	Unamortized Loss on Reacquired Debt	(103,608)
	Unamortized Insurance Premiums	0
	Net Proceeds Available	$8,283,376

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

Exhibit___(APD/RBM-1, Schedule 6, Workpaper 4)
Page 1 of 1

COST OF LONG-TERM DEBT
ESTIMATED AS OF DECEMBER 31, 2011

Line No.	Coupon Rate	Maturity Date	Date of Issue	Principal Amount Issued	Discount Or (Premium)	Expenses	Net Proceeds	% Of Principal Amount	Cost Of Money	Principal Amount Outstanding	Annual Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
First Mortgage Bonds											
1	Net Loss on Reacquired Debt (a)									(43,209,058)	5,107,944
	First Mortgage Bonds Totals			$0			$0		-11.82%	($43,209,058)	$5,107,944
Senior Notes											
2	5.13%	11/15/2012	11/15/2002	$200,000,000	$0	$1,520,958	$198,479,042	99.24%	5.22%	##########	##########
3	5.40%	3/1/2033	2/19/2003	144,289,000	0	6,413,965	137,875,035	95.55%	5.71%	144,289,000	8,240,489
4	5.75%	4/15/2023	4/15/2003	100,000,000	0	3,355,825	96,644,175	96.64%	6.04%	100,000,000	6,041,300
5	5.90%	4/15/2033	4/15/2003	150,000,000	0	11,269,363	138,730,637	92.49%	6.47%	150,000,000	9,705,900
6	4.90%	9/15/2013	9/15/2003	100,000,000	0	3,494,541	96,505,459	96.51%	5.36%	100,000,000	5,355,900
7	6.00%	10/15/2033	10/15/2003	200,000,000	0	6,519,591	193,480,409	96.74%	6.24%	200,000,000	12,483,400
8	5.75%	1/15/2044	1/15/2004	100,000,000	0	3,287,551	96,712,449	96.71%	5.97%	100,000,000	5,966,800
9	6.00%	8/15/2044	8/21/2004	125,000,000	0	10,091,760	114,908,240	91.93%	6.57%	125,000,000	8,217,250
10	5.70%	1/1/2045	1/1/2005	250,000,000	0	8,424,206	241,575,794	96.63%	5.92%	250,000,000	14,802,250
11	5.80%	4/15/2035	4/15/2005	125,000,000	0	2,210,027	122,789,973	98.23%	5.93%	125,000,000	7,408,500
12	5.25%	12/15/2015	12/15/2005	250,000,000	0	2,338,278	247,661,722	99.06%	5.37%	250,000,000	13,430,250
13	4.90%	12/15/2013	7/1/2006	25,000,000	0	742,873	24,257,127	97.03%	5.39%	25,000,000	1,347,200
14	5.50%	12/15/2028	7/1/2006	35,000,000	0	1,707,214	33,292,786	95.12%	5.89%	35,000,000	2,063,005
15	5.75%	12/1/2044	7/1/2006	35,000,000	0	1,060,336	33,939,664	96.97%	5.95%	35,000,000	2,082,885
16	5.65%	12/15/2040	12/15/2006	150,000,000	0	9,139,888	140,860,112	93.91%	6.08%	150,000,000	9,113,850
17	5.65%	3/1/2037	3/13/2007	250,000,000	1,102,500	6,209,955	242,687,545	97.08%	5.86%	250,000,000	14,645,250
18	5.70%	6/1/2017	6/12/2007	450,000,000	972,000	-5,551,295	454,579,295	101.02%	5.57%	450,000,000	25,043,850
19	6.38%	7/15/2047	7/15/2007	300,000,000	0	5,541,125	294,458,875	98.15%	6.51%	300,000,000	19,515,600
20	6.00%	9/1/2040	8/30/2007	250,000,000	0	7,598,645	242,401,355	96.96%	6.22%	250,000,000	15,544,750
21	6.05%	12/1/2038	12/1/2007	100,000,000	0	3,293,974	96,706,026	96.71%	6.29%	100,000,000	6,292,900
22	5.40%	6/1/2018	6/1/2008	250,000,000	1,122,500	6,678,181	242,199,319	96.88%	5.82%	250,000,000	14,539,750
23	8.20%	11/1/2048	11/12/2008	100,000,000	0	3,371,692	96,628,308	96.63%	8.50%	100,000,000	8,496,700
24	6.00%	11/1/2013	11/12/2008	400,000,000	256,000	2,619,070	397,124,930	99.28%	6.17%	400,000,000	24,678,000
25	5.95%	2/1/2039	2/1/2009	500,000,000	1,860,000	23,518,110	474,621,890	94.92%	6.33%	500,000,000	31,649,000
26	4.25%	12/1/2019	12/1/2009	500,000,000	0	16,451,100	483,548,900	96.71%	4.67%	500,000,000	23,325,000
27	3.30%	3/1/2013	3/1/2010	350,000,000	0	7,000,000	343,000,000	98.00%	4.01%	350,000,000	14,050,050
28	5.70%	6/1/2040	6/1/2010	150,000,000	0	3,000,000	147,000,000	98.00%	5.84%	150,000,000	8,763,150
29	6.45%	10/1/2040	10/1/2010	200,000,000	0	4,000,000	196,000,000	98.00%	6.60%	200,000,000	13,208,000
30	3.30%	3/1/2013	3/1/2011	350,000,000	0	7,000,000	343,000,000	98.00%	4.36%	350,000,000	15,242,500
31	6.65%	3/1/2041	3/1/2011	250,000,000	0	5,000,000	245,000,000	98.00%	6.81%	250,000,000	17,018,250
32	7.30%	12/1/2041	12/1/2011	100,000,000	0	2,000,000	98,000,000	98.00%	7.47%	100,000,000	7,468,000
33	Net Loss on Reacquired Debt (a)									(9,484,174)	475,336
34	Senior Notes Totals			###########	########	##########	###########		5.81%	###########	$376,662,265

(a) See Workpaper 5 of this schedule.

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

REACQUIRED DEBT
ESTIMATED AS OF DECEMBER 31, 2011

Line No.	Date Reacquired	Reacquired Amount	Monthly Amortization	Annual Cost (4) * 12
(1)	(2)	(3)	(4)	(5)
First Mortgage Bonds				
1	07/06	(434,792)	8,204	98,444
2	07/06	(770,660)	8,287	99,440
3	07/06	(421,406)	10,805	129,663
4	07/06	(316,960)	1,981	23,772
5	07/06	(484,682)	6,827	81,918
6	07/06	(244,719)	3,447	41,361
7	01/89	(135,101)	4,268	51,213
8	12/86	(2,536,398)	46,970	563,644
9	12/86	(1,318,884)	24,424	293,085
10	11/87	(2,845,889)	43,810	525,717
11	01/87	(50,310)	2,431	29,173
12	01/88	(874,876)	13,470	161,643
13	01/91	(278,160)	17,235	206,817
14	07/93	(376,631)	4,829	57,943
15	07/95	(616,950)	6,494	77,931
16	07/93	(1,365,691)	13,553	162,631
17	04/92	(907,401)	7,377	88,527
18	05/92	(2,803,828)	11,398	136,772
19	07/93	(6,868,842)	48,947	587,363
20	07/92	(3,644,799)	20,621	247,449
21	06/94	(384,619)	7,123	85,471
22	11/92	(85,667)	801	9,608
23	11/92	(85,667)	801	9,608
24	11/92	(85,667)	801	9,608
25	11/92	(85,668)	801	9,608
26	12/92	(85,668)	801	9,608
27	02/93	(85,924)	803	9,636
28	04/93	(1,110,041)	8,284	99,407
29	12/98	(2,065,494)	15,300	183,599
30	04/95	(263,773)	1,085	13,026
31	07/95	(464,881)	3,780	45,354
32	01/97	(374,863)	2,999	35,987
33	07/95	(261,903)	1,065	12,776
34	12/98	(3,798,452)	28,560	342,717
35	03/99	(3,460,226)	24,894	298,725
36	03/99	(2,046,821)	15,275	183,297
37	06/99	(1,455,137)	9,095	109,135
Loss on Reacquired Debt		(43,497,451)	427,640	5,131,676
38	09/96	143,503	(897)	(10,763)
39	09/96	136,283	(1,017)	(12,204)
40	09/96	8,606	(64)	(765)
Gain on Reacquired Debt		288,393	(1,978)	(23,732)
First Mortgage Bonds Total		(43,209,058)	425,662	5,107,944
Senior Notes				
41	03/03	(3,029,643)	11,881	142,571
42	11/03	(3,952,267)	15,028	180,332
43	03/04	(2,319,083)	6,039	72,471
44	03/04	(0)	0	0
45	03/08	(139,873)	477	5,720
46	09/08	(43,307)	6,187	74,241
47	08/09	0	0	0
Loss on Reacquired Debt		(9,484,174)	39,611	475,336

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

COST OF LONG-TERM DEBT
ESTIMATED AS OF DECEMBER 31, 2011

Line No.	Coupon Rate	Maturity Date	Date of Issue	Principal Amount Issued	Expenses	Discount Or (Premium)	Net Proceeds	% Of Principal Amount	Cost Of Money	Principal Amount Outstanding	Annual Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Pollution Control Bonds											
1	5.84%	5/1/2022	5/1/1992	$13,155,000	$264,503	$0	$12,890,497	97.99%	5.99%	$ 13,155,000	$ 787,340
2	5.84%	2/1/2038	2/1/1993	4,085,000	84,994	0	4,000,006	97.92%	5.97%	4,085,000	244,026
3	3.75%	10/1/2032	7/1/1994	10,000,000	169,342	0	9,830,658	98.31%	3.83%	10,000,000	383,450
4	5.75%	10/1/2032	7/1/1994	55,000,000	2,347,873	0	52,652,127	95.73%	6.04%	55,000,000	3,320,075
5	3.75%	10/1/2032	7/1/1994	55,000,000	595,556	0	54,404,444	98.92%	3.80%	55,000,000	2,092,035
6	3.20%	10/1/2032	7/1/1994	55,000,000	754,686	0	54,245,314	98.63%	3.26%	55,000,000	1,794,595
7	2.05%	10/1/2032	10/1/1994	20,000,000	531,762	0	19,468,238	97.34%	2.15%	20,000,000	430,560
8	3.75%	10/1/2032	10/1/1994	20,000,000	320,242	0	19,679,758	98.40%	3.83%	20,000,000	766,060
9	2.05%	10/1/2032	4/1/1995	75,000,000	1,321,254	0	73,678,746	98.24%	2.12%	75,000,000	1,588,725
10	5.84%	7/1/2025	7/1/1995	45,000,000	687,441	0	44,312,559	98.47%	5.95%	45,000,000	2,677,410
11	3.75%	10/1/2032	9/1/1995	30,000,000	423,629	0	29,576,371	98.59%	3.82%	30,000,000	1,146,420
12	3.20%	10/1/2032	9/1/1995	27,000,000	473,690	0	26,526,310	98.25%	3.28%	27,000,000	886,167
13	5.10%	6/1/2023	6/1/1996	26,400,000	653,516	0	25,746,484	97.52%	5.27%	26,400,000	1,392,072
14	5.10%	6/1/2023	6/1/1996	24,945,000	715,206	0	24,229,794	97.13%	5.30%	24,945,000	1,322,310
15	5.84%	9/1/2026	9/1/1996	3,800,000	91,052	0	3,708,948	97.60%	6.01%	3,800,000	228,505
16	5.84%	9/1/2026	9/1/1996	10,080,000	142,163	0	9,937,837	98.59%	5.94%	10,080,000	598,883
17	2.05%	10/1/2032	9/1/1996	46,000,000	919,917	0	45,080,083	98.00%	2.13%	46,000,000	979,662
18	2.05%	4/1/2032	4/1/1997	20,800,000	653,395	0	20,146,605	96.86%	2.18%	20,800,000	453,170
19	2.05%	4/1/2032	4/1/1997	19,600,000	485,523	0	19,114,477	97.52%	2.15%	19,600,000	421,616
20	5.75%	10/1/2032	4/1/1997	49,600,000	2,286,255	0	47,313,745	95.39%	6.07%	49,600,000	3,009,629
21	5.00%	10/1/2032	9/1/1997	50,000,000	2,662,510	0	47,337,490	94.67%	5.34%	50,000,000	2,668,550
22	5.15%	9/1/2029	9/1/1997	37,000,000	1,434,698	0	35,565,302	96.12%	5.41%	37,000,000	2,000,257
23	5.84%	9/1/2029	9/1/1997	18,500,000	699,952	0	17,800,048	96.22%	6.11%	18,500,000	1,130,461
24	2.05%	9/1/2029	9/1/1997	33,700,000	574,562	0	33,125,438	98.30%	2.12%	33,700,000	715,687
25	5.15%	9/1/2029	9/1/1997	17,500,000	369,291	0	17,130,709	97.89%	5.29%	17,500,000	925,295
26	2.05%	9/1/2029	9/1/1997	38,000,000	756,317	0	37,243,683	98.01%	2.14%	38,000,000	811,756
27	5.10%	3/1/2024	3/1/1998	46,790,000	1,672,587	0	45,117,413	96.43%	5.36%	46,790,000	2,506,213
28	5.84%	3/1/2024	3/1/1998	13,725,000	124,316	0	13,600,684	99.09%	5.91%	13,725,000	810,955
29	2.05%	3/1/2025	3/1/1998	17,000,000	293,342	0	16,706,658	98.27%	2.13%	17,000,000	362,848
30	5.45%	5/1/2034	5/1/1999	53,000,000	649,373	246,980	52,103,647	98.31%	5.56%	53,000,000	2,946,906
31	4.35%	9/1/2018	9/1/2001	14,075,000	700,626	0	13,374,374	95.02%	4.78%	14,075,000	672,940
32	5.84%	12/1/2018	12/21/2001	19,500,000	215,554	0	19,284,446	98.89%	5.94%	19,500,000	1,159,080
33	2.05%	2/1/2016	2/1/2003	13,870,000	258,404	0	13,611,596	98.14%	2.22%	13,870,000	307,331
34	4.75%	5/1/2034	5/1/2005	85,000,000	1,077,740	1,700,000	82,222,260	96.73%	4.96%	85,000,000	4,219,230
35	4.63%	5/1/2034	5/1/2005	100,000,000	869,876	1,625,000	97,505,124	97.51%	4.79%	100,000,000	4,790,100
36	2.05%	7/1/2031	6/28/2006	10,125,000	274,095	0	9,850,905	97.29%	2.19%	10,125,000	221,859
37	4.40%	7/1/2016	7/1/2006	67,000,000	631,883	0	66,368,117	99.06%	4.52%	67,000,000	3,027,261
38	4.90%	7/1/2036	7/1/2006	48,720,000	552,924	0	48,167,076	98.87%	4.97%	48,720,000	2,422,943
39	2.05%	12/1/2041	12/13/2006	28,065,000	534,948	0	27,530,052	98.09%	2.13%	28,065,000	597,083
40	5.84%	12/1/2037	12/1/2007	17,800,000	0	0	17,800,000	100.00%	5.84%	17,800,000	1,039,520
41	2.05%	7/1/2022	7/1/2008	53,000,000	194,386	0	52,805,614	99.63%	2.08%	53,000,000	1,102,559
42	5.84%	11/1/2048	11/19/2008	68,535,000	464,176	0	68,070,824	99.32%	5.88%	68,535,000	4,032,599
43	3.75%	11/1/2048	11/20/2008	65,000,000	529,403	0	64,470,597	99.19%	3.79%	65,000,000	2,463,305
44	5.84%	11/1/2048	11/21/2008	83,515,000	467,012	0	83,047,988	99.44%	5.88%	83,515,000	4,907,508
45	2.05%	7/1/2049	7/1/2009	40,000,000	368,803	0	39,631,197	99.08%	2.08%	40,000,000	833,640
46	2.05%	7/1/2049	7/1/2009	114,310,000	741,759	0	113,568,241	99.35%	2.07%	114,310,000	2,370,789
47	2.05%	9/1/2049	9/1/2009	90,000,000	1,800,000	0	88,200,000	98.00%	2.12%	90,000,000	1,912,050
48	2.05%	10/1/2049	10/1/2009	173,000,000	3,460,000	0	169,540,000	98.00%	2.12%	173,000,000	3,675,385
49	Net Loss on Reacquired Debt (a)									(50,626,691)	4,095,655
50	Pollution Control Bond Totals			$2,027,195,000			$1,987,322,483		4.21%	$1,976,568,309	$83,252,475
51	Long Term Debt Totals			$8,516,484,000			$8,301,991,551		5.53%	$8,413,164,077	$465,022,684

(a) See Workpaper 7 of this schedule.

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

REACQUIRED DEBT
ESTIMATED AS OF DECEMBER 31, 2011

Line No.	Date Reacquired	Reacquired Amount	Monthly Amortization	Annual Cost (4) * 12
(1)	(2)	(3)	(4)	(5)
Pollution Control Bonds				
1	12/87	(462,582)	7,009	84,106
2	12/87	(206,067)	3,122	37,467
3	12/87	(198,914)	3,014	36,166
4	09/91	(40,273)	353	4,239
5	09/91	(24,561)	273	3,275
6	09/91	0	0	0
7	09/91	(61,945)	543	6,521
8	09/91	0	0	0
9	10/91	(148,390)	1,302	15,620
10	10/91	(285,437)	2,504	30,046
11	10/91	(419,413)	3,679	44,149
12	08/94	(1,854,914)	12,467	149,600
13	09/94	(1,968,752)	13,271	159,252
14	09/94	(2,054,564)	14,043	168,521
15	09/95	(960,105)	23,417	281,006
16	11/91	(11,335)	246	2,957
17	11/94	(2,299,657)	15,825	189,904
18	06/92	(145,855)	1,176	14,115
19	09/92	(295,923)	2,330	27,961
20	09/92	(285,007)	2,244	26,930
21	12/92	(110,327)	862	10,343
22	12/92	(145,877)	1,140	13,676
23	12/92	(82,890)	648	7,771
24	12/92	(303,182)	2,369	28,423
25	02/96	(26,989)	365	4,377
26	02/96	(34,289)	463	5,560
27	02/96	(46,722)	631	7,577
28	09/93	(508,788)	3,634	43,611
29	09/93	(69,491)	496	5,956
30	09/93	(1,142,039)	8,157	97,889
31	11/94	(178,383)	1,166	13,991
32	03/94	(981,670)	6,899	82,785
33	09/95	(4,800,934)	30,292	363,499
34	10/96	(35,979)	204	2,453
35	10/95	(662,288)	4,038	48,460
36	11/95	(753,272)	4,593	55,117
37	07/96	(420,096)	3,066	36,797
38	07/96	(438,403)	3,200	38,400
39	10/96	(900,606)	5,117	61,405
40	10/96	(31,386)	178	2,140
41	10/96	(97,876)	556	6,673
42	10/96	(74,370)	423	5,071
43	07/96	(1,222,603)	5,031	60,375
44	07/96	(487,762)	2,007	24,087

GEORGIA POWER COMPANY

REACQUIRED DEBT
ESTIMATED AS OF DECEMBER 31, 2011

Line No.	Date Reacquired	Reacquired Amount	Monthly Amortization	Annual Cost (4) * 12
(1)	(2)	(3)	(4)	(5)
Pollution Control Bonds (cont'd)				
45	07/96	(458,905)	1,888	22,662
46	09/97	(724,264)	3,416	40,996
47	09/97	(696,035)	3,283	39,398
48	09/97	(133,557)	630	7,560
49	09/97	(170,494)	804	9,651
50	09/97	(374,144)	1,765	21,178
51	09/97	(248,118)	1,170	14,044
52	09/97	(469,161)	2,213	26,556
53	12/97	(543,430)	7,654	91,847
54	04/98	(705,879)	4,835	58,017
55	04/98	(191,721)	1,313	15,758
56	04/98	(126,383)	866	10,388
57	04/98	(247,448)	1,566	18,794
58	04/98	(99,753)	631	7,576
59	04/98	(74,861)	513	6,153
60	06/99	(1,157,788)	4,320	51,841
61	07/99	(1,860,716)	12,405	148,857
62	08/99	(1,022,240)	6,770	81,238
63	08/00	(407,666)	2,647	31,766
64	07/01	(270,743)	4,923	59,071
65	07/01	(48,052)	890	10,678
66	09/01	(169,664)	2,121	25,450
67	07/01	(151,606)	648	7,775
68	07/01	(462,716)	1,977	23,729
69	10/01	(22,506)	281	3,376
70	10/01	(31,085)	389	4,663
71	09/01	(263,485)	1,733	20,802
72	10/01	(514,910)	2,145	25,746
73	10/01	(1,249,049)	5,204	62,453
74	10/01	0	13,928	167,138
75	10/01	0	1,771	21,252
76	02/02	(53,865)	605	7,263
77	02/02	(27,691)	379	4,552
78	05/05	(1,222,140)	4,543	54,519
79	07/05	(2,141,561)	7,991	95,891
80	06/06	(555,889)	2,260	27,117
81	07/06	(716,030)	13,260	159,118
82	07/06	(1,052,904)	3,569	42,830
83	12/06	(826,606)	2,222	26,665
84	07/06	(406,001)	1,336	16,026
85	07/06	(72,839)	232	2,784
86	09/08	(76,082)	312	3,742
87	09/08	0	0	0

GEORGIA POWER COMPANY

REACQUIRED DEBT
ESTIMATED AS OF DECEMBER 31, 2011

Line No.	Date Reacquired	Reacquired Amount	Monthly Amortization	Annual Cost (4) * 12
(1)	(2)	(3)	(4)	(5)
Pollution Control Bonds (cont'd)				
88	09/08	(8,446)	34	405
89	09/08	(161,078)	1,918	23,011
90	09/08	(21,251)	86	1,037
91	09/08	(2,663)	54	652
92	09/08	(233,577)	749	8,984
93	09/08	(223,415)	1,759	21,110
94	12/08	(899,737)	2,031	24,372
95	12/08	(421,597)	954	11,446
96	07/09	(481,082)	1,069	12,829
97	07/09	(960,219)	2,134	25,606
98	07/09	(432,258)	961	11,527
99	09/09	(499,937)	1,992	23,901
100	09/09	(504,731)	2,011	24,131
101	09/09	(448,798)	1,788	21,456
Loss on Reacquired Debt		(50,626,691)	341,305	4,095,655

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

COST OF PREFERRED SECURITIES
ESTIMATED AS OF DECEMBER 31, 2011

Line No.	Interest Rate	Date of Prospectus	Issue Date	Amount Issued	Discount (Premium)	Expenses	Net Proceeds	Net Proceeds Per Share	Cost Of Money	Preferred Securities Outstanding	Annual Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	5.88%	06/25/03	01/23/04	206,185,575	0	6,350,816	199,834,759	96.92%	6.06%	206,185,575	12,498,351
2	Net Loss on Reacquired Debt (a)									(28,896,805)	2,159,113
3	Preferred Securities Totals			$206,185,575					8.27%	$177,288,770	$14,657,464

(a) See Workpaper 9 of this schedule.

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

REACQUIRED DEBT
ESTIMATED AS OF DECEMBER 31, 2011

Line No.	Date Reacquired	Reacquired Amount	Monthly Amortization	Annual Cost (4) * 12
(1)	(2)	(3)	(4)	(5)
Preferred Securities				
1	12/99	(1,743,231)	8,421	101,057
2	07/02	(4,394,084)	14,946	179,350
3	12/02	(4,011,638)	13,240	158,877
4	07/02	(3,399,661)	11,804	141,653
5	02/04	(4,465,748)	11,630	139,555
6	07/06	(488,149)	7,455	89,462
7	06/07	(6,776,839)	102,679	1,232,153
8	11/07	(3,617,456)	9,751	117,007
Loss on Reacquired Debt		(28,896,805)	179,926	2,159,113

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

COST OF PREFERRED STOCK
ESTIMATED AS OF DECEMBER 31, 2011

Line No.	Div Rate (No Par)	Date of Prospectus	Issue Date	Stated Value	Discount (Premium)	Expenses	Redemption Loss/(Gain)	Net Proceeds	Net Proceeds Per Share	Cost Of Money	Preferred Stock Outstanding	Annual Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	$ 6.125		7/1/2006	$ 45,000,000	$0	$ 8,640	$0	$44,991,360	99.98%	6.13%	$ 45,000,000	$ 2,756,700
2	Preferred Stock Totals			$ 45,000,000	$0	$ 8,640	$0	$ 44,991,360		6.13%	$ 45,000,000	$ 2,756,700

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

COST OF PREFERENCE STOCK
ESTIMATED AS OF DECEMBER 31, 2011

Line No.	Div Rate (No Par)	Date of Prospectus	Issue Date	Stated Value	Discount (Premium)	Expenses	Redemption Loss/(Gain)	Net Proceeds	Net Proceeds Per Share	Cost Of Money	Preferred Stock Outstanding	Annual Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	$ 6.50		10/1/2007	225,000,000	0	4,034,383	0	220,965,617	98.21%	6.6200%	225,000,000	14,895,000
2	$ 7.40		6/1/2010	100,000,000	0	2,000,000	0	98,000,000	98.00%	7.5500%	100,000,000	7,550,000
3	$ 8.50		6/1/2011	100,000,000	0	2,000,000	0	98,000,000	98.00%	8.6700%	100,000,000	8,670,000
4	Preference Stock Totals			$ 425,000,000	$0	$ 8,034,383	$0	$ 416,965,617		7.32%	$ 425,000,000	$ 31,115,000

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

RATE OF RETURN
COMMON STOCK CAPITAL
(Amounts in Thousands)

Since the Southern Company owns all of the common stock of Georgia Power Company, the following relate to the common stock capital of Southern Company:

Sales of Common Stock during the Six Year Period Ended December 31, 2009.

Year	Number of Shares Sold (a)	Total Proceeds
2004	6,714	123,571
2005	10,076	213,395
2006	53	1,182
2007	11,639	379,099
2008	14,113	473,374
2009	42,536	1,285,807

GEORGIA POWER COMPANY

RATE OF RETURN
COMMON STOCK CAPITAL

Since the Southern Company owns all of the common stock of Georgia Power Company, the following relate to the common stock capital of Southern Company:

Common Stock for each of the Six Calendar Years Ended December 31, 2009

Year	AVERAGE NUMBER OF SHARES OUTSTANDING (000)	BOOK VALUE PER SHARE	ANNUAL EARNINGS PER SHARE	ANNUAL DIVIDEND PER SHARE	DIVIDEND PAYOUT RATIO	AVERAGE MARKET PRICE	PRICE EARNINGS RATIO	DIVIDEND YIELD
2004	738,879	$13.86	$2.07	$1.415	68.30%	$30.70	16.2	4.2
2005	743,927	$14.42	$2.14	$1.475	69.00%	$33.81	16.1	4.3
2006	743,146	$15.24	$2.12	$1.535	72.40%	$33.94	17.4	4.2
2007	756,350	$16.23	$2.29	$1.595	69.65%	$36.26	16.9	4.1
2008	771,039	$17.08	$2.26	$1.6625	73.56%	$35.21	16.4	4.5
2009	794,795	$18.15	$2.07	$1.7325	83.70%	$32.05	16.1	5.2

GEORGIA POWER COMPANY

RECONCILIATION OF 12/31/09 RETAIL CAPITAL STRUCTURE TO 12/31/11 RETAIL CAPITAL STRUCTURE

LINE NO.	COMPONENT	ACTUAL BALANCE 12/31/09	NEW ISSUES	RETIREMENTS	OTHER	PROJECTED BALANCE 12/31/11
(1)	(2)	(3) ($000)	(4) ($000)	(5) ($000)	(6) ($000)	(7) ($000)
1	Long-Term Debt	$7,209,706	$1,400,000 (a)	($358,330) (a)	$31,887 (b)	$8,283,263
2	Preferred Securities	167,563			4,634 (b)	$172,197
3	Preferred and Preference Stock	270,000	200,000 (a)			$470,000
4	Common Equity	7,919,025			1,190,667 (c)	$9,109,692
5	TOTAL	$15,566,294	$1,600,000	($358,330)	$1,227,188	$18,035,152

(a) See Workpaper 15 of this schedule.
(b) Amortization of Debt Issuance Expenses, Debt Discount, and Gain/Loss on Reacquired Debt (see Workpapers 5, 7, and 9 of this schedule).
(c) Projected net change in Retained Earnings (Net Income Less Common Stock Dividends) from 12/31/09 to 12/31/11.

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

RECONCILIATION OF 12/31/09 RETAIL CAPITAL STRUCTURE TO PROJECTED 12/31/11 RETAIL CAPITAL STRUCTURE

LINE NO.	COUPON RATE	DATE OF ISSUE	MATURITY DATE	NEW ISSUES	RETIREMENTS		
					CALLS & REPURCHASES	MATURITIES	TOTAL RETIREMENTS
(1)	(2)	(3) ($000)	(4) ($000)	(5) ($000)	(6) ($000)	(7) ($000)	(8) ($000)
Pollution Control Bonds							
1	Variable	07/01/91	07/01/11			$8,330	$8,330
Senior Notes							
2	Variable	03/17/08	03/17/10			$250,000	$250,000
3	Variable	03/01/10	03/01/13	$350,000			
4	5.70%	06/01/10	06/01/40	$150,000			
5	6.45%	10/01/10	10/01/40	$200,000			
6	4.00%	01/15/04	01/15/11			$100,000	$100,000
7	Variable	03/01/11	03/01/13	$350,000			
8	6.65%	03/01/11	03/01/41	$250,000			
9	7.30%	12/01/11	12/01/41	$100,000			
Preferred and Preference Stock							
10	7.40%	06/01/10		$100,000			
11	8.50%	06/01/11		$100,000			
12	TOTAL			$1,600,000	$0	$358,330	$358,330

GEORGIA POWER COMPANY

ELECTRIC PLANT-IN-SERVICE
ESTIMATED AS OF DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION			BALANCE AS OF 12/31/2011	THIRTEEN MONTH AVERAGE
(1)	(2)			(3)	(3)
1	Intangible Plant		$	332,996	307,265
2	Production Plant			14,428,325	13,959,323
3	Transmission Plant			4,470,580	4,358,160
4	Distribution Plant			8,414,521	8,214,170
5	General Plant	(a)		1,131,603	1,121,688
6	Electric Plant Held for Future Use	(b)		93,921	93,921
7	Total Electric Plant		$	28,871,945	28,054,528
8	Nuclear Fuel	(c)		568,756	561,163
9	Total Electric Plant and Nuclear Fuel		$	29,440,701	28,615,691

(a) Original budget adjusted to include monthly deferred depreciation charges on the Rome headquarters building, which were inadvertently omitted. The adjustment results in an increase of $19.

(b) Original budget was prepared based on actual balances through August 2009 and has been adjusted to appropriately reflect activity in the last quarter of 2009, resulting in an increase of $53,012.

(c) Original budget adjusted to appropriately reclassify Vogtle 3 and 4 balances from nuclear fuel plant in service to nuclear fuel CWIP. The reclassification results in a decrease of $41,043.

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION
ESTIMATED AS OF DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION		BALANCE AS OF 12/31/2011	THIRTEEN MONTH AVERAGE
(1)	(2)		(3)	(4)
1	Intangible Plant	$	217,437	212,283
2	Production Plant		6,043,729	5,868,043
3	Transmission Plant		1,219,872	1,187,111
4	Distribution Plant		2,962,955	2,859,772
5	General Plant		438,819	418,815
6	Accumulated Depreciation and Amortization of Electric Plant	$	10,882,812	10,546,023
7	Nuclear Fuel		244,981	227,259
8	Total Accumulated Depreciation and Amortization of Electric Plant and Nuclear Fuel	$	11,127,793	10,773,283

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

OTHER RATE BASE ITEMS
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	MONTH	PREPAID PENSION ASSET	CUSTOMER DEPOSITS	ACCUMULATED INTEREST ON CUSTOMER DEPOSITS	OPERATING RESERVES	HAMMOND COOLING TWR RENTAL	DEFERRED NUCLEAR OUTAGE COSTS	DEFERRED MCINTOSH INSPECTIONS	ECCR OVER/UNDER RECOVERY OF COSTS (a)	COST OF REMOVAL REGULATORY ASSET/LIAB.	GREEN ENERGY OVER/UNDER RECOVERY (b)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(7)	(7)	(8)	(9)	(10)
1	12/31/10	$517,634	($227,587)	($26,135)	($198,720)	$16,245	$27,075	$7,585	$13,188	$0	($450)
2	01/31/11	518,008	(231,142)	(26,135)	(200,659)	15,793	28,333	7,200	0	0	(450)
3	02/28/11	518,381	(234,470)	(26,135)	(203,572)	15,342	20,764	6,815	0	0	(450)
4	03/31/11	518,754	(236,580)	(26,135)	(206,424)	14,891	6,327	6,430	0	0	(450)
5	04/30/11	519,128	(238,577)	(26,135)	(211,399)	14,440	4,054	6,045	0	0	(450)
6	05/31/11	519,501	(240,033)	(26,135)	(216,448)	13,988	6,575	5,660	0	0	(450)
7	06/30/11	519,875	(241,473)	(26,135)	(209,231)	13,537	9,742	5,275	0	0	(450)
8	07/31/11	520,248	(245,718)	(26,135)	(206,195)	13,086	13,239	4,890	0	0	(450)
9	08/31/11	520,621	(246,994)	(26,135)	(229,284)	12,635	14,148	4,505	0	0	(450)
10	09/30/11	520,995	(248,276)	(26,135)	(228,157)	12,183	9,326	4,120	0	0	(450)
11	10/31/11	521,368	(249,287)	(26,135)	(231,045)	11,732	6,780	3,735	0	0	(450)
12	11/30/11	521,741	(252,431)	(26,135)	(233,218)	11,281	9,268	3,350	0	0	(450)
13	12/31/11	522,115	(254,830)	(26,135)	(215,737)	10,830	12,424	2,965	0	0	(450)
14	13-MONTH TOTAL	$6,758,369	($3,147,398)	($339,755)	($2,790,088)	$175,983	$168,058	$68,577	$13,188	$0	($5,850)
15	13-MONTH AVERAGE	$519,875	($242,108)	($26,135)	($214,622)	$13,537	$12,928	$5,275	$1,014	$0	($450)

(a) See Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1) page 13 of 14 Footnote AB for budget correction.
(b) See Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1) page 13 of 14 Footnote Z for budget correction.
Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

WORKING CAPITAL
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
1	MATERIALS AND SUPPLIES (13-MONTH AVERAGE INVENTORY):	
2	PRODUCTION FUEL STOCK - COAL	$377,618
3	PRODUCTION FUEL STOCK - OIL	63,016
4	PRODUCTION FUEL STOCK - GAS	36,591
4	EMISSIONS	30,423
5	OTHER MATERIALS AND SUPPLIES	375,505
7	TOTAL MATERIALS AND SUPPLIES	$883,152
8	MINIMUM BANK BALANCES	$15,000
9	PREPAYMENTS	74,830
10	PETTY CASH	91
11	TOTAL MINIMUM BANK BALANCES, PREPAYMENTS, PETTY CASH	$89,921
12	CASH WORKING CAPITAL	$200,844
13	TOTAL WORKING CAPITAL	$1,173,917

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

WORKING CAPITAL
MATERIALS AND SUPPLIES
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	MONTH	COAL INVENTORY (a)	OIL INVENTORY	GAS INVENTORY (a)	EMISSIONS INVENTORY (a)	PLANT MATERIALS & SUPPLIES	TOTAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	12/31/10	$463,621	$62,956	$14,392	$19,711	$371,344	$932,025
2	01/31/11	408,915	63,002	14,866	19,029	372,033	877,846
3	02/28/11	383,101	63,040	14,865	18,445	372,723	852,174
4	03/31/11	384,763	63,068	14,498	17,892	373,414	853,636
5	04/30/11	405,620	63,089	38,016	17,392	374,107	898,224
6	05/31/11	404,884	63,112	37,831	16,746	374,801	897,374
7	06/30/11	384,414	63,134	46,623	43,077	375,496	912,743
8	07/31/11	363,134	63,152	47,279	42,283	376,192	892,040
9	08/31/11	332,210	63,168	47,789	41,476	376,890	861,532
10	09/30/11	318,145	63,182	48,008	40,774	377,589	847,697
11	10/31/11	337,641	62,758	48,607	40,128	378,289	867,423
12	11/30/11	352,788	62,769	50,398	39,572	378,990	884,518
13	12/31/11	369,799	62,778	52,507	38,969	379,693	903,746
14	TOTAL	$4,909,034	$819,208	$475,679	$395,497	$4,881,561	$11,480,979
15	13-MONTH AVERAGE	$377,618	$63,016	$36,591	$30,423	$375,505	$883,152

(a) See Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1) page 12 of 14 Footnote R for budget correction.
Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

WORKING CAPITAL
AVERAGE MINIMUM BANK BALANCES, PREPAYMENTS, AND PETTY CASH
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	MONTH	MINIMUM BANK BALANCES	PREPAY-MENTS	PETTY CASH	TOTAL
(1)	(2)	(3)	(4)	(5)	(6)
1	12/31/10	$15,000	$79,477	$91	$94,568
2	01/31/11	15,000	73,786	91	88,877
3	02/28/11	15,000	61,722	91	76,813
4	03/31/11	15,000	54,100	91	69,191
5	04/30/11	15,000	45,060	91	60,151
6	05/31/11	15,000	42,420	91	57,510
7	06/30/11	15,000	54,166	91	69,257
8	07/31/11	15,000	72,634	91	87,724
9	08/31/11	15,000	91,208	91	106,299
10	09/30/11	15,000	109,635	91	124,726
11	10/31/11	15,000	99,159	91	114,250
12	11/30/11	15,000	100,219	91	115,310
13	12/31/11	15,000	89,200	91	104,291
14	TOTAL	$195,000	$972,786	$1,181	$1,168,967
15	13-MONTH AVERAGE	$15,000	$74,830	$91	$89,921

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

CALCULATION OF CASH WORKING CAPITAL
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
AS BUDGETED
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT	LAG/ LEAD DAYS	DOLLAR DAYS
	(2)	(3)	(4)	(5)
1	Operating Revenues		38.1	
	Cash Operating Expenses:			
2	Fuels Other Than Nuclear	$ 3,022,995	(16.2)	($48,972,516)
3	Nuclear Fuel Disposal Costs	18,919	(75.9)	(1,435,949)
4	Nuclear Decommissioning	3,462	(258.0)	(893,196)
	Purchased Power:			
5	Purchases-Power Pool (net)*	442,988	2.5	1,107,470
6	Purchases-Non Power Pool (net)*	541,334	3.5	1,894,671
	Other Operating and Maintenance			
7	Expenses	1,819,666	(27.9)	(50,768,673)
8	Taxes Other Than Income Taxes	346,413	(149.5)	(51,788,809)
	Current Income Taxes:			
9	Federal	160,637	(37.5)	(6,023,891)
10	State	(29,596)	(37.5)	1,109,849
11	Interest Expense - Long Term Debt	386,207	(64.4)	(24,871,731)
12	Interest Expense - Preferred Securities	35,674	(45.0)	(1,605,330)
13	Preferred Dividends	3,102	(45.0)	(139,590)
14	Total Cash Operating Expenses	$6,751,801	(27.0)	($182,387,695)
15	Net Lag Days		11.1	
16	Average Daily Cash Operating Expenses (Total / 365)		$18,498	
17	Cash Working Capital Before Adjustments		$205,328	
18	Adjustment for Sales Tax Collection		(4,484)	
19	Cash Working Capital - As Budgeted		$200,844	

* These amounts include combined credits of $73,034 representing power sales which are credited to retail revenue for regulatory reporting purposes.

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

TAXES OTHER THAN INCOME TAXES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
(Amounts in Thousands)

Line No.	Description	Total Taxes	Account 408	Other	Total	Construction	Non-Utility
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Real and Personal Property						
2	Georgia	$159,433	$129,916	$2,169	$132,085	$15,505	$11,843
3	Alabama	1,474	406	0	406	0	1,068
4	Florida	208	208	0	208	0	0
5	Mississippi	267	267	0	267	0	0
6	South Carolina	75	61	0	61	0	14
7	Total Real and Personal Property	$161,457	$130,858	$2,169	$133,027	$15,505	$12,925
8	Payroll Taxes	$50,676	$39,720	$0	$39,720	$10,956	$0
9	State of Georgia Taxes						
10	Occupation (Corporate)	5	5	0	5	0	0
11	Motor Vehicle	0	0	**0**	0	0	0
12	State of Alabama Taxes						
13	Corporate Franchise Tax	15	15	0	15	0	0
14	Municipal Franchise Fees	173,529	173,529	0	173,529	0	0
15	Other	117	112	5	117	0	0
16	Total Taxes Other Than Income Taxes	$385,799	$344,239	$2,174	$346,413	$26,461	$12,925

Note: Details May Not Add To Totals Due To Rounding

GEORGIA POWER COMPANY

TAXES OTHER THAN INCOME TAXES
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

Real and Personal Property Taxes:
Real and Personal Property Taxes for the twelve months ending December 31, 2011 are estimated to total $130,858,000.

Real and Personal Property Taxes for the test period are based on the estimated fair market value of the Company at January 1. Non-taxable items such as pollution control equipment, vehicles locally assessed, and leasehold improvements are then subtracted from the gross value. The fair market value is multiplied by the estimated assessment ratios to arrive at the assessed value. The assessed value is then multiplied by the estimated composite millage rate to calculate the amount of property tax liability. Operating income is projected to increase in future years, resulting in an increase in the Company's appraised value and tax liability. The State of Georgia's share is approximately 99% of the total.

Payroll Taxes:
Payroll Taxes are computed using payroll history as a base, and adjusted for changes in personnel growth, wages, and payroll tax rates.

Municipal Franchise Fees:
Franchise fees are paid to municipalities where there are signed franchise agreements. The fee is computed on the total of all retail revenues billed within corporate city limits.

Franchise fees are collected from the Company's customers in accordance with the Commission's order in Docket No. 21112. To support this methodology, a separate calculation is necessary, and is detailed on Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1). Accordingly, the municipal franchise fees are collected through the Municipal Franchise Fee (MFF) tariff and have been removed from the income expansion gross up factor in determining the retail rate base revenue requirement.

The historical period is based on the twelve months ended December 2009. The Municipal Franchise Fee to Retail Revenue ratio yields the following rate:

$$\frac{\$159,000,620}{\$6,864,449,000} = 0.023$$

The above rate is then applied to the 2011 projected Calendar Year Period Retail Revenues of $7,479,698,275, which results in electric service Municipal Franchise Fees of $173,529,000. This amount is an increase to the historical period due to a projected increase in retail revenues.

GEORGIA POWER COMPANY

NON-DEDUCTIBLE BOOK DEPRECIATION
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

Line	Description	Unrecovered Non-Deductible Book Depreciation December 31, 2010	Average Composite Remaining Life	Recovery 12/31/2010-12/31/2011
(1)	(2)	(3)	(4)	(5)
1	Vintage Years (Excluding Nuclear Fuel)			
2	1954-2011	1,152,478	28	41,733
3	Total (Excluding Nuclear Fuel)			41,733
4	Add: Non-Deductible Book Depreciation Associated with Nuclear Fuel		Note 1	1,895
5	Total Non-Deductible Book Depreciation (Electric)			43,628

Note 1 Non-deductible book depreciation associated with nuclear fuel is based on burn during the test period for all vintages of property. The non-deductible book depreciation amount is applicable to basis differences in burn similar to that portion of book depreciation on all other property.

Note 2 The above calculation represents non-deductible book depreciation for Federal purposes. A similar calculation is made for State non-deductible book depreciation which differs from the Federal amount due to the differences in depreciation basis of property for State and Federal purposes.

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

SUMMARY OF ACCUMULATED DEFERRED INVESTMENT TAX CREDITS
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

Line	Description	Unamortized Balances at December 31, 2010	Provision	Amortization	Unamortized Balances at December 31, 2011
(1)	(2)	(3)	(4)	(5)	(6)
1	Federal Investment Tax Credits:				
2	Electric-3% (Pre-1971)	$70	$0	(68)	$2
3	Electric-4%	5,300	0	(1,029)	$4,271
4	Electric-10%	223,885	0	(12,067)	$211,818
5	Total Federal Investment Tax Credits	$229,255	$0	($13,164)	$216,091

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

SUMMARY OF ACCUMULATED DEFERRED INCOME TAXES
FOR THE TWELVE MONTHS ENDING December 31, 2011
(Amounts in Thousands)

Line No.	Description	Balances at December 31, 2010 State	Balances at December 31, 2010 Federal	PROVISION State	PROVISION Federal	FEEDBACK State	FEEDBACK Federal	ADJUSTMENT State	ADJUSTMENT Federal	Balances at December 31, 2011 State	Balances at December 31, 2011 Federal	RATE BASE 13- MONTH AVERAGE Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Account 281 - Accelerated Amortization											
2	Accelerated Amortization Property	41,322	259,507	8,921	54,042	0	0	0	0	50,243	313,549	332,313
3	TOTAL ACCOUNT 281	41,322	259,507	8,921	54,042	0	0	0	0	50,243	313,549	332,313
4	Account 282 - Electric											
5	Accelerated Depreciation - Electric	323,573	2,333,849	8,752	24,354	3,103	15,520	0	0	335,428	2,373,723	2,690,322
6	Accelerated Depreciation - Nuclear Fuel	1,858	11,666	(797)	(4,928)	0	0	0	0	1,061	6,738	10,662
7	Basis Differences	7,808	33,761	1,160	7,016	0	0	0	0	8,968	40,777	45,657
8	TOTAL ACCOUNT 282	333,239	2,379,276	9,115	26,442	3,103	15,520	0	0	345,457	2,421,238	2,746,641
9	Account 283											
10	Premium on Reacquired Debt	7,847	48,520	0	0	(845)	(5,224)	0	0	7,002	43,296	53,333
11	Deferred Interest	47	289	0	0	(47)	(289)	0	0	(0)	0	26
12	Additional Pension Deduction	25,156	155,546	0	0	0	0	0	0	25,156	155,546	180,701
13	Nuclear Outage	2,395	14,804	962	5,949	(1,791)	(11,076)	0	0	1,565	9,677	8,030
14	Fuel Under Recovery	51,540	314,521	9,897	61,196	(670)	(4,140)	(60,767)	(371,577)	0	0	0
15	Storm Damage	1,040	6,426	0	0	(370)	(2,290)	0	0	669	4,136	6,135
16	McIntosh Cost Deferral	429	2,655	0	0	(262)	(1,617)	0	0	168	1,038	2,145
17	Def. Revenues	417	2,582	0	0	0	0	0	0	417	2,582	2,999
18	Levelized Purchase Power	1,318	8,148	3,882	24,001	(4,255)	(26,312)	0	0	944	5,837	6,529
19	DSM	315	1,948	0	0	0	0	0	0	315	1,948	2,263
20	Other Deferred Cost	52	319	0	0	0	0	0	0	52	319	371
21	Hammond Cooling Towers	917	5,672	0	0	(307)	(1,895)	0	0	611	3,777	5,489
22	Emission Allowances	1,226	7,583	0	0	0	0	0	0	1,226	7,583	8,810
23	Affirmative Adjustments	3,349	19,345	0	0	0	0	0	0	3,349	19,345	22,694
24	TOTAL ACCOUNT 283	96,047	588,359	14,741	91,146	(8,546)	(52,844)	(60,767)	(371,577)	41,474	255,084	299,525
25	Account 190											
26	Injuries and Damages Reserve	(126)	(778)	0	0	0	0	0	0	(126)	(778)	(904)
27	Reserve for Outstanding Insurance Claims	(595)	(3,682)	0	0	0	0	0	0	(595)	(3,682)	(4,277)
28	Accrual For Uncollectible	(781)	(4,828)	0	0	0	0	0	0	(781)	(4,828)	(5,609)
29	GE Purchasing Card	(48)	(298)	0	0	0	0	0	0	(48)	(298)	(346)
30	Cost of Removal	0	0	0	0	0	0	0	0	0	0	0
31	Other Deferred Costs	(30,805)	(190,477)	445	2,753	(1,354)	(8,369)	0	0	(31,713)	(196,094)	(224,547)
32	Income Taxes Deferred - Electric	0	(144,665)	0	(11,359)	0	3,465	0	21,032	0	(131,526)	(130,441)
33	Affirmative Adjustments	(572)	(1,781)	0	0	0	0	0	0	(572)	(1,781)	(2,353)
34	FIN 48	(8,539)	(49,995)	0	0	0	0	0	0	(8,539)	(49,995)	(58,534)
35	TOTAL ACCOUNT 190	(41,466)	(396,504)	445	(8,606)	(1,354)	(4,904)	0	21,032	(42,374)	(388,982)	(427,011)
36	TOTAL RATE BASE	429,142	2,830,637	33,221	163,024	(6,797)	(42,228)	(60,767)	(350,545)	394,800	2,600,889	2,951,468
37	NON-RATE BASE											
39	TOTAL NON-RATE BASE	66,651	377,949	293	2,072	(1,543)	(6,422)	63,591	371,968	128,991	745,566	
40	TOTAL ALL ACCUMULATED DEFERRED INCOME TAXES	495,793	3,208,586	33,514	165,096	(8,340)	(48,650)	2,824	21,423	523,791	3,346,455	

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

DEVELOPMENT OF SYNCHRONIZED INTEREST EXPENSE ADJUSTMENT
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

	AMOUNT
Total Rate Base for Interest Synchronization (Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1) Page 5 of 14	$ 13,281,697
Component Cost of Long-Term Debt and Preferred Securities (Exhibit___(APD/RBM-1, Schedule 5, Workpaper 1, Column 5, Line 1+2))	2.57%
Synchronized Interest Expense	$ 341,340
Interest Expense as Budgeted	445,354
Synchronized Interest Adjustment	($104,014)
Tax Effect of Synchronized Interest Adjustment:	
Current Federal Income Tax Provision	$ 34,346
Current State Income Tax Provision	5,887
TOTAL	$40,233

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

UNREGULATED OUTDOOR LIGHTING
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
	REVENUE	
1	Other Operating Revenues	$77,730
	EXPENSES	
2	Distribution	$5,369
3	Customer Accounts	457
4	Customer Service	0
5	Energy Services	4,648
6	Administrative & General	2,108
7	Total O&M	$12,581
	Depreciation Expense:	
8	Depreciation Expense	$13,525
	Taxes Other Than Income Taxes:	
9	Real & Personal Property Taxes	$1,469
10	FICA	207
11	FUTA	4
12	Municipal Franchise Fees	1,805
13	Total Taxes Other Than Income Taxes	$3,485
	Income Taxes:	
1	Federal	($9,006)
2	State	(1,231)
3	Deferred Income Taxes	(8,383)
4	Total Income Taxes	($18,620)
	Electric Plant-in-Service:	
1	Distribution	$276,346
2	General Plant	5,260
3	Total Electric Plant-in-Service	$281,606
	Accumulated Depreciation:	
1	Distribution	$80,827
2	General Plant	1,964
3	Total Accumulated Depreciation	$82,791
4	Materials and Supplies	698
	Accumulated Deferred Income Taxes:	
1	Account 282 - Other Property	$70,614
2	Account 190 - Prepaid	(2,646)

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

ESTIMATED IMPACT OF NEW DEPRECIATION RATES
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	Depreciation Rates PREVIOUS	Depreciation Rates NEW (a)	ESTIMATED IMPACT OF NEW RATES
(1)	(2)	(3)	(4)	(5)
1	Steam Plant	3.80%	3.61%	$ 6,696
2	Nuclear Plant	1.33%	1.37%	$ 1,582
3	Hydro Plant	2.26%	2.20%	$ (325)
4	Other Production	2.73%	2.86%	$ 1,982
5	Transmission Plant	2.25%	2.31%	$ 4,317
6	Distribution Plant	3.07%	3.16%	$ 6,969
7	General:			
8	Structures and Improvements	2.08%	2.08%	$ (4)
9	Transportation Equipment	14.48%	14.34%	$ (264)
10	Power Operated Equipment	15.44%	18.78%	$ 351
11	Communication Equipment	7.15%	6.20%	$ (2,192)
12	Office Furniture and Equipment	Amortized	Amortized	
13	Auxiliary Plant (393-395 & 398)	Amortized	Amortized	$ -
14	Total General			$ (2,109)
15	Total Electric Plant Depreciation Expense			$ 19,112

(a) Depreciation Study filed as Appendix, Exhibit 2.

Note: Details may not add to total due to rounding.

GEORGIA POWER COMPANY

SUMMARY OF DEPRECIATION VARIANCE
CALENDAR YEAR 2011 VERSUS DEPRECIATION STUDY
(Amounts in Thousands)

LINE NO.	VARIANCE	ESTIMATED IMPACT OF NEW RATES
(1)	(2)	(3)
1	Depreciation Study Rate Change Impact	$ (584) [a]
	Adjusted for:	
2	- Plant McDonough Units 1 and 2 (excluded from depreciation study)	$ 2,656
3	- Dismantlement and asset retirement obligation (ARO) associated with projected plant retirements in 2014 (amortized over a 4 year dismantlement period consistent with commission approved methodology in the 2004 retail rate case Docket No. 18300)	$ 11,007
4	- Increase in calendar year 2011 depreciable base	$ 6,033
5	Total Depreciation Column Adjustment	$ 19,112 [b]

(a) Depreciation Study filed as Appendix, Exhibit 2.
(b) Included in the proposed one-year depreciation deferral amount as shown in Supplemental Item S-48.

Note: Details may not add to total due to rounding.

GEORGIA POWER COMPANY

NUCLEAR DECOMMISSIONING EXPENSE
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.		2009 NRC OPTION 2 COST (2009 $)	ESTIMATED COST AT LICENSE EXPIRATION DATE	REMAINING SERVICE YEARS	TOTAL DECOMMISSIONING EXPENSE	LESS INTERNALLY FUNDED AMOUNT	CONTRIBUTION AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)
	Plant Hatch						
1	Unit 1	$291,442	$507,488	25	$392	$0	$392
2	Unit 2	329,287	627,516	28	1,294	0	$1,294
3	Total	$620,729	$1,135,004		$1,686	$0	$1,686
	Plant Vogtle						
4	Unit 1	$191,020	$473,915	37	$0	$0	$0
5	Unit 2	218,683	569,141	39	0	0	$0
6	Total	$409,703	$1,043,056		$0	$0	$0
				GRAND TOTAL	$1,686	$0	$1,686

Assumes 2.42% annual cost escalation.
Assumes 4.42% annual earnings rate.

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

STORM DAMAGE RESERVE
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

Actual Reserve Deficiency at 12/31/2009	($23,133)
2010 Accrual per the Commission's Order in Docket 25060	$21,433
Estimated 2010 Expense	($14,889)
Estimated Reserve Deficiency at 12/31/2010	($16,589)

Projected Annual Expense Based on 5 year Historical Average:

	Amount
Twelve Months Ended 12/31/2005	$ 26,496
Twelve Months Ended 12/31/2006	(3,698)
Twelve Months Ended 12/31/2007	10,020
Twelve Months Ended 12/31/2008	23,888
Twelve Months Ended 12/31/2009	17,737
5 year average	$ 14,889
2010 Deficiency Amortized over 3 Year Period	$5,530
New Accrual	$ 20,419
Current Accrual	$21,433
Estimated Revenue Requirement Decrease	$1,014

GEORGIA POWER COMPANY

CALCULATION OF ADJUSTED CASH WORKING CAPITAL
ESTIMATED FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
(Amounts in Thousands)

Line No.	Description	Amount	Lag / Lead Days	Dollar Days
(1)	(2)	(3)	(4)	(5)
1	Operating Revenues		38.1	
	Cash Operating Expenses:			
2	Fuels Other Than Nuclear	$ 3,022,995	(16.2)	$ (48,972,516)
3	Nuclear Fuel Disposal Costs	18,919	(75.9)	(1,435,949)
4	Nuclear Decommissioning	1,686	(258.0)	(434,988)
	Purchased Power:			
5	Purchases-Power Pool (net) *	475,461	2.5	1,188,652
6	Purchases-Non Power Pool (net) *	553,858	3.5	1,938,501
7	Other Operating and Maintenance Expenses	1,697,637	(27.9)	(47,364,065)
8	Taxes Other Than Income Taxes**	171,204	(149.5)	(25,595,029)
	Current Income Taxes:			
9	Federal	239,795	(37.5)	(8,992,294)
10	State	(3,227)	(37.5)	121,026
11	Interest Exp.- Long Term Debt	330,714	(64.4)	(21,297,982)
12	Interest Exp.- Preferred Securities	30,548	(45.0)	(1,374,660)
13	Preferred and Preference Dividends	2,656	(45.0)	(119,520)
14	Total Cash Operating Expenses	$ 6,542,244	(23.3)	$ (152,338,824)
12	Net Lag Days		14.8	
13	Average Daily Cash Operating Expenses (Total/ 365)		$ 17,924	
14	Cash Working Capital (Before Adjustments)		$ 265,275	
15	Adjustment for Sales Tax Collection		(4,484)	
16	Cash Working Capital		$ 260,791	
17	Per Books Cash Working Capital		200,844	
18	Cash Working Capital Adjustment		$ 59,947	

* These amounts include combined credits of $73,034 representing power sales which are credited to retail revenue for regulatory reporting purposes.

** Excludes municipal franchise fees.

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY Exhibit (APP/RBM-2, Schedule 7, Workpaper 7)

TRANSMISSION SPECIFIC ASSIGNMENTS - PLANT SCHERER
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
	REVENUE	
	Other Operating Revenues:	
1	Revenue Credits	$27,679
	EXPENSES	
2	Transmission O&M	$3,075
	Administrative and General:	
3	920	$133
4	921	85
5	922	(4)
6	923	487
7	924	305
8	925	88
9	926	306
10	928	27
11	929	(32)
12	930	53
13	931	47
14	935	47
15	Total Administrative and General	$1,542
	Depreciation Expense:	
16	Transmission - 115kv and Above	$3,631
17	General Plant	220
18	Total Depreciation Expense	$3,851
	Taxes Other Than Income Taxes:	
19	Payroll Taxes:	
20	FICA	$102
21	Total Payroll Taxes	$102
22	Property Taxes	$867

23	Total Taxes Other Than Income Taxes	$960
24	Amortization of ITC - Transmission	($51)

Note: Details may not add due to rounding.

TRANSMISSION SPECIFIC ASSIGNMENTS - PLANT SCHERER
ESTIMATED THIRTEEN MONTH AVERAGE ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
1	Electric Plant in Service (115+kv lines and subs)	$163,483
	General Plant:	
2	Land	$154
3	All Other	3,235
4	Total General Plant	$3,389
	Accumulated Provision for Depreciation:	
5	Transmission 115kv+ Facilities	$43,311
6	General Plant	1,338
7	Total Accumulated Provision for Depreciation	$44,649
	Working Capital:	
8	Transmission M&S	$1,275
9	Minimum Bank Balances	89
10	Prepayments	1,385
11	Total Working Capital	$2,749
12	Operating Reserves	($544)
	Accumulated Deferred Income Taxes	
13	Account 190:	
14	Injuries and Damages Reserve	($3)
15	Reserve for Insurance Claims	(14)
16	Other Deferred Costs	(579)
17	Income Taxes Deferred - Electric	(1,053)
18	Total Account 190	($1,649)
	Account 282:	
19	Accelerated Depreciation - Electric	$23,040
20	Other Basis Differences	1,562
21	Total Account 282	$24,602

	Account 283:	
22	Premium on Reacquired Debt	$284
23	Storm Damage	61
24	Pension Deduction	604
25	Total Account 283	$949
26	Total Accumulated Deferred Income Taxes	$23,902

Note: Details may not add due to rounding.

GEORGIA POWER COMPANY

WHOLESALE BLOCKS SPECIFIC ASSIGNMENTS
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
	REVENUE	
	Sales of Electricity:	
1	Fuel	$285,381
2	Emission	-
3	Variable O&M	30,661
4	Total Energy Revenue	$316,042
5	Capacity Revenue	161,075
6	Total Sales of Electricity	$477,117
7	TOTAL REVENUES	$477,117
	EXPENSES	
8	O&M Expenses:	
9	Fuel	$285,381
10	Emission	-
11	Variable O&M	30,661
12	Total Fuel & Variable O&M	$316,042
13	Total Steam Power Generation Account 500-514	$22,222
	Other Power Supply	
14	555 - Purchased Power	$10,415
15	Total Other Power Supply	$10,415
16	Transmission	$41

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

WHOLESALE BLOCKS SPECIFIC ASSIGNMENTS
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
	Administrative and General:	
1	920	$819
2	921	519
3	922	(22)
4	923	2,988
5	924 - Production	521
6	924 - Transmission	11
7	924 - General	8
8	925	536
9	926	2,751
10	928	1,893
11	929	(194)
12	930	(523)
13	931	915
14	935	286
15	Total Administrative and General	$10,508
	Depreciation Expense:	
16	Production	$34,963
17	Transmission -- Generator Step-up Substation	397
18	General Plant	536
19	Total Depreciation Expense	$35,896
	Taxes Other Than Income Taxes:	
20	Payroll Taxes:	$1,131
21	Total Payroll Taxes	$1,131
	Property Taxes:	
22	Production	$2,204
23	Transmission GSU	81
24	General	45
25	Total Property Taxes	$2,330
26	Total Taxes Other Than Income Taxes	$3,461

27	Amortization of ITC - Production Steam	($12)
28	Total Amortization of ITC	($12)

Note: Details may not add to totals due to rounding.

WHOLESALE BLOCKS SPECIFIC ASSIGNMENTS
ESTIMATED THIRTEEN MONTH AVERAGE ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
	Electric Plant in Service:	
	Production:	
1	Land	$3,799
2	Other	773,510
3	Total Production	$777,309
4	Generator Step-up Substations	$17,413
	General Plant:	
5	Land	$382
6	All Other	8,022
7	Total General Plant	$8,404
8	Intangible	$2,449
9	Total Electric Plant-in Service	$805,575

Note: Details may not add to totals due to rounding.

WHOLESALE BLOCKS SPECIFIC ASSIGNMENTS
ESTIMATED THIRTEEN MONTH AVERAGE ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
	Accumulated Provision for Depreciation:	
1	Production	$394,067
2	GSU	7,921
3	General Plant	3,315
4	Intangible	1,692
5	Total Accumulated Provision for Depreciation	$406,995
	Working Capital:	
6	Materials & Supplies -	
7	Coal and Oil Inventory	$36,980
8	Emission Allowance Inventory	2,489
9	Plant M&S	14,677
10	Minimum Bank Balances	400
11	Prepayments	21,281
12	Total Working Capital	$75,827
13	Operating Reserves	($5,167)
	Accumulated Deferred Income Taxes	
	Account 190:	
14	Injuries and Damages Reserve	($6)
15	Outstanding Insurance Claims	(34)
16	Other Deferred	(6,175)
17	Other Deferred Electric	(1,724)
18	Total Account 190	($7,939)
	Account 282:	
19	Accelerated Depreciation - Electric	$52,121
20	Other Basis Differences	(1,671)
21	Total Account 282	$50,450
	Account 283:	
22	Premium on Reacquired Debt	$2,240
23	Pension Deduction	6,429
24	Total Account 283	$8,669

25	Total Accumulated Deferred Income Taxes		

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

DALTON SPECIFIC ASSIGNMENTS
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
	REVENUE	
	Sales of Electricity:	
1	Fuel	$23,672
2	Emission	-
3	Variable O&M	2,146
4	Total Energy Revenue	$25,818
5	Capacity Revenue	14,768
6	Total Sales of Electricity	$40,586
7	TOTAL REVENUES	$40,586
	EXPENSES	
	O&M Expenses:	
8	Fuel	$23,672
9	Emission	-
10	Variable O&M	2,146
11	Total Fuel & Variable O&M	$25,818
12	Total Steam Power Generation Account 500-514	$2,314
13	Transmission	$2

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

DALTON SPECIFIC ASSIGNMENTS
ESTIMATED FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
	Administrative and General:	
1	920	$74
2	921	47
3	922	(2)
4	923	269
5	924 - Production	80
6	924 - Transmission	2
7	924 - General	1
8	925	48
9	926	248
10	928	210
11	929	(17)
12	930	(47)
13	931	83
14	935	26
15	Total Administrative and General	$1,022
	Depreciation Expense:	
16	Production	$3,049
17	Transmission -- Generator Step-up Substation	48
18	General Plant	48
19	Total Depreciation Expense	$3,145
	Taxes Other Than Income Taxes:	
20	Payroll Taxes:	$112
21	Total Payroll Taxes	$112
	Property Taxes:	
22	Production	$258
23	Transmission GSU	10
24	General	4
25	Total Property Taxes	$272
26	Total Taxes Other Than Income Taxes	$384

27	Amortization of ITC - Production	($34)
28	Total Amortization of ITC	($34)

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

DALTON SPECIFIC ASSIGNMENTS
ESTIMATED THIRTEEN MONTH AVERAGE ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
	Electric Plant in Service:	
	Production:	
1	Land	$1,021
2	Other	83,353
3	Total Production	$84,374
4	Generator Step-up Substations	$2,083
	General Plant:	
5	Land	$34
6	All Other	722
7	Total General Plant	$756
8	Intangible	$220
9	Total Electric Plant-in Service	$87,433

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

DALTON SPECIFIC ASSIGNMENTS
ESTIMATED THIRTEEN MONTH AVERAGE ENDING DECEMBER 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION	AMOUNT
(1)	(2)	(3)
	Accumulated Provision for Depreciation:	
1	Production	$33,351
2	GSU	918
3	General Plant	298
4	Intangible	152
5	Total Accumulated Provision for Depreciation	$34,719
	Working Capital:	
6	Materials & Supplies -	
7	Coal and Oil Inventory	$4,529
8	Emission Allowance Inventory	198
9	Limestone Inventory	20
10	Plant M&S	1,634
11	Minimum Bank Balances	47
12	Prepayments	2,118
13	Total Working Capital	$8,546
14	Operating Reserves	($465)
	Accumulated Deferred Income Taxes	
	Account 190:	
15	Injuries and Damages Reserve	($1)
16	Outstanding Insurance Claims	(3)
17	Other Deferred	(611)
18	Other Deferred Electric	(147)
19	Total Account 190	($762)
	Account 282:	
20	Accelerated Depreciation - Electric	$7,744
21	Other Basis Differences	159
22	Total Account 282	$7,903
	Account 283:	
23	Premium on Reacquired Debt	$265
24	Pension Deduction	636
25	Total Account 283	$901

26	Total Accumulated Deferred Income Taxes	Sch 42

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

COMPUTATION OF THE TEST PERIOD RETAIL REVENUE DEFICIENCY
ESTIMATED FOR THE TWELVE MONTHS ENDING JULY 31, 2011
(Amounts in Thousands)

LINE NO.	DESCRIPTION		TOTAL REVENUE DEFICIENCY	
(1)	(2)		(3)	
1	Retail Rate Base	$	14,425,450	(a)
2	Requested Rate of Return	x	8.71%	(b)
3	Earnings Requirement	$	1,256,457	
4	Deduct: Earnings Available for Return		794,855	(a)
5	Earnings Deficiency	$	461,602	
6	Income Expansion Factor	÷	61.059%	(c)
7	Revenue Deficiency Excluding Municipal Franchise Fees (MFF)	$	755,993	
8	Less: ECCR Revenue Deficiency	-	181,317	(d)
9	Traditional Base Revenue Deficiency	$	574,676	

(a) From Exhibit____(MTO-1)
(b) From M.F.R Item D-1(e) Page 2 of 2
(c) From Exhibit____(APD/RBM-3, Schedule 1) page 2 of 3
(d) From Exhibit____(APD/RBM-3, Schedule 2 ECCR) page 1 of 4

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

DERIVATION OF INCOME EXPANSION FACTOR
ESTIMATED FOR THE TWELVE MONTHS ENDING JULY 31, 2011

1 Additional Revenue				100.000%
2 Less:				
Federal and State Income Taxes				-38.679%
Net After Income Taxes				61.321%
3 Less:				
Uncollectible Accounts				
Estimated Test Year Uncollectible Accounts Expense /	$ 32,994	=	0.462%	
Estimated Test Year Retail Revenues (Excl Street & Hwy Lightning)	$ 7,140,663			
Reduction in Income Taxes = .462% x 38.679%			-0.179%	
Net Effect of Uncollectible Accounts				-0.283%
Net After Income Taxes and Uncollectible Accounts				61.038%
4 Add:				
Additional Compensation for Collecting State Sales Tax				
Estimated Test Year Sales Tax on Revenue /	$ 502,104	=	6.963%	
Estimated Test Year Retail Revenues	$ 7,211,545			
Collection Fee = 0.5%				
Compensation Percentage = 6.963% x 0.5%			0.035%	
Increase in Income Taxes = 0.035% x 38.679%			-0.013%	
Net Effect of Additional Compensation				0.021%
5 After Tax Effect of Additional Revenue				61.059%

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

COMPUTATION OF THE IMPACT OF MUNICIPAL FRANCHISE FEES (MFF)
ESTIMATED FOR THE TWELVE MONTHS ENDING JULY 31, 2011
(Amounts in Thousands)

Line No.	Description		Amounts	
(1)	(2)		(3)	
1	Total Budgeted Revenue Before MFF:	(a)	7,213,949	
2	% of Revenues Inside Municipalities	(b)	58.00%	
3	Portion Inside the Municipalities:		4,184,091	
4	MFF Rate		4.0%	
5	MFF Expenses			$ 167,364
6	MFF Expense Lead Days		(236.3)	
7	Revenue Lag Days (c)		38.1	
8	Net Lag Days		(198.2)	
9	Calendar Year Days		365	
10	Average MFF Working Capital		$ (90,858)	
11	Pre-Tax Weighted Average Cost of Capital (d)		12.68%	
12	Carrying Charge on Pro Forma Average MFF Working Capital			$ (11,521)
13	Adjusted Calendar Year - MFF Expenses			$ 155,843
14	Franchise Fees included in Current Rates			(151,947)
15	Additional MFF revenue requirement on existing rates			$ 3,895
16	MFF rate to be used on incremental revenue requirements		2.16%	
17	(155,843 / 7,213,949)			
18	Incremental MFF revenue requirement on Traditional Base Rate Tariff =			
19	$574,676 (e) x 2.16%			$ 12,415
20	Incremental MFF revenue requirement on ECCR = $181,317 (f) x 2.16%			$ 3,916
21	Incremental MFF revenue requirement on DSM = $31,673 (g) x 2.16%			$ 684
22	Total MFF Revenue Deficiency			$ 20,911

(a) From Test Period Forecasted Retail Revenues Less: Test Period Projected MFF
(b) From 2009 Percent of Revenues Located within Municipalities
(c) From Exhibit___(APD/RBM-3, Schedule 4) page 35 of 35
(d) From Exhibit___(APD/RBM-3, Schedule 2 ECCR) page 4 of 4
(e) From Exhibit____(APD/RBM-3, Schedule 1, Workpaper 1) page 1 of 3
(f) From Exhibit___(APD/RBM-3, Schedule 2 ECCR) page 1 of 4
(g) From Exhibit___(APD/RBM-3, Schedule 3 DSM) page 1 of 4

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
PROJECTED FOR 12 MONTHS ENDING JULY 31, 2011
(Amounts in Thousands)

	12 Months Ending July, 31 2011	
Retail Rate Base	$ 1,845,763	Note 1
Requested Rate of Return	8.71%	Note 2
Earnings Requirement	$ 160,766	
Deduct Earnings Available for Return	(74,990)	Note 3
Earnings Deficiency	$ 235,756	
Income Expansion Factor	61.059%	Note 2
Subtotal Revenue Deficiency	**$ 386,110**	
Amortization of 2010 Regulatory Asset (2011-2013)	7,586	Note 4
Return Required on Unamortized Regulatory Asset	1,468	Note 4
Total Revenue Deficiency	**$ 395,165**	
Less Present Rates Revenue Available	(213,848)	
Total Increase Required	**$ 181,317**	

Total Revenue Deficiency by Component: (Note 5)	
Environmental Capital Costs (excl Book Depreciation)	$ 224,454
Environmental Book Depreciation Expense	79,120
Environmental O&M Expenses (incl Env Remediation)	82,537
Amortization & Return on 2010 Regulatory Asset	9,055
Total	**$ 395,165**

Note 1 - Rate base is based on the projected 13-month average balances of electric plant in service, accumulated depreciation and accumulated deferred income taxes for each period. Amounts used for retail revenue requirement calculations exclude wholesale allocations to UPS, Wholesale Block, and Dalton. From page 2 of 4.

Note 2 - From Exhibit___(APD/RBM-3, Schedule 1, Workpaper 1), Page 1 of 3.

Note 3 - From page 2 of 4.

Note 4 - From page 4 of 4. Test period amounts are normalized to reflect full annual impact.

Note 5 - Projected revenue requirements for the twelve months ending July 31, 2011 are based on the same capital and O&M budgets that were filed in Docket No. 31081 on a calendar year basis.

GEORGIA POWER COMPANY

ENVIRONMENTAL INVESTMENT AND EXPENSES
PROJECTED FOR 12 MONTHS ENDING JULY 31, 2011
(Amounts in Thousands)

Line No.	Description	Total Company Less Wholesale	Retail Allocator Note 1	Adjusted Retail
	Ending July 31, 2011			
1	Electric Plant in Service	$ 2,150,209	0.99952	$ 2,149,177
2	Accumulated Depreciation	(159,361)	0.99952	(159,284)
3	Net Plant in Service	$ 1,990,848		$ 1,989,892
4	Accumulated Deferred Income Taxes	(144,189)	0.99959	(144,130)
5	TOTAL RATE BASE	$ 1,846,659		$ 1,845,763
6	Operating Expenses	$ 72,805	0.99951	$ 72,769
7	Environmental Remediation Accrual	9,418	0.99969	9,415
8	Depreciation Expense	78,821	0.99951	78,782
9	Federal Income Taxes (From page 3 of 4)			(63,561)
10	State Income Taxes (From page 3 of 4)			(22,415)
11	EARNINGS AVAILABLE FOR RETURN	$ (161,043)		$ (74,990)

Note 1: From Exhibit___(APD/RBM-1, Schedule 1, Workpaper 1), Pages 4 and 5 of 14.

GEORGIA POWER COMPANY

ENVIRONMENTAL STATE & FEDERAL INCOME TAXES
PROJECTED FOR 12 MONTHS ENDING JULY 31, 2011
(Amounts in Thousands)

Line No.	Description		Twelve Months Ending July 31, 2011	
1	State Tax Calculation			
2	Operating Expenses	$	82,184	Note 1
3	Depreciation Expense		78,782	Note 2
4	Interest Expense		46,144	
5	Environmental Expenses Before Taxes	$	207,110	
6	Less:			
7	Non-Deductible Depreciation Expense		3,090	
8	Plus:			
9	State Income Tax Deduction		(11,548)	
10	Environmental Expenses Subject to State Tax	$	192,472	
11	State Tax Rate		6.00%	
12	State Tax on Environmental Expenses	$	(11,548)	
13	State Tax Credits on Environmental Expenditures		(10,867)	
14	Net State Income Tax - Environmental	$	(22,415)	
15	Federal Tax Calculation			
16	Environmental Expenses Before Taxes	$	207,110	
17	Less:			
18	Non-Deductible Depreciation Expense		3,090	
19	Plus:			
20	State Income Tax Deduction		(11,548)	
21	Environmental Expenses Subject to Federal Tax	$	192,472	
22	Federal Tax Rate		35.00%	
23	Federal Tax on Environmental Expenses	$	(67,365)	
24	State Tax Credits on Environmental Expenditures		3,804	
25	Net Federal Income Tax - Environmental	$	(63,561)	

Note 1 - From page 2 of 4, including Environmental Remediation Accrual.
Note 2 - From page 2 of 4.

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
2010 ENVIRONMENTAL COSTS & REGULATORY ASSET
(Amounts in Thousands)

	2010 Budget 2010	Docket No. 25060 2010	Regulatory Asset
Retail Electric Plant in Service (13-month average balance)	$ 1,994,388	$ 1,791,175	
Accumulated Depreciation	(114,968)	(108,789)	
Accumulated Deferred Income Taxes	(104,953)	(103,970)	
Net Rate Base	$ 1,774,468	$ 1,578,416	
Retail Revenue Requirement Rate	12.03%	12.52%	
Revenue Requirement on Net Rate Base	$ 213,468	$ 197,618	$ 15,851
Depreciation Expense	78,360	70,050	8,310
State Manufacturer's Investment Tax Credit	(11,983)	(8,396)	(3,587)
Revenue Requirement on Total Capital	**$ 279,846**	**$ 259,272**	**$ 20,573**
Operating Expenses	64,807	62,719	2,089
Total Revenue Requirement	**$ 344,653**	**$ 321,991**	**$ 22,662**

Amortization & Return Required on 2010 Regulatory Asset:	Normalized
Amortization of 2010 Regulatory Asset (2011-2013)	$ 7,586
Return Required on Unamortized 2010 Regulatory Asset:	
Unamortized Regulatory Asset (13-month average balance net of taxes)	$ 11,580
Retail Revenue Requirement Rate	12.68%
Return Required on Unamortized 2010 Regulatory Asset	$ 1,468

Component	Proportion	Average Cost	Average Component Cost	Revenue Requirement Rate
Ending July 31, 2011				
Long-Term Debt	46.09%	5.26%	2.42%	2.43%
Preferred Securities	1.00%	8.36%	0.08%	0.08%
Preferred Stock	0.27%	6.13%	0.02%	0.03%
Preference Stock	2.01%	6.97%	0.14%	0.23%
Common Equity	50.63%	11.95%	6.05%	9.91%
TOTAL	100.00%		8.71%	12.68%

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
Demand Side Management (DSM) Tariff
Projected for 12 Months Ending July 31, 2011

Line No.	Description	12 Months Ending July 31, 2011
1	**Residential Programs**	
2	Incentive Costs	2,668,372
3	Non-Incentive Costs	5,123,960
4	Cross-Cutting Costs	450,000
5	Additional Sum	0
6	Previously-Certified Program Costs & Other DSM	16,150,000
7	***Residential Sub-total***	24,392,332
8	**Commercial Programs**	
9	Incentive Costs	2,328,460
10	Non-Incentive Costs	2,723,200
11	Cross-Cutting Costs	450,000
12	Additional Sum	0
13	***Commercial Sub-total***	5,501,660
14	***Total DSM Tariff Costs***	**29,893,993**
15	Amort of DSM Deferred Asset - FERC 407	2,972,658
16	Carrying Costs on Deferred Asset	1,063,473
17	***DSM Tariff - Ancillary Impact Costs***	4,036,131
18	***TOTAL DSM TARIFF COSTS***	**33,930,124**
19	*Federal and State Income Taxes*	13,123,833
20	*DSM Cost Tariff Costs After Tax*	20,806,291
21	*Income Expansion Factor*	0.61059
22	***DSM Tariff Revenue Requirement***	**34,075,644**
23	***DSM Revenues Included in current Tariffs***	**(2,402,928)**
24	***Total DSM Tariff Revenue Requirement***	**31,672,716**

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
DSM Incentive and Program Cost Detail
Projected for 12 Months Ending July 31, 2011

Line No.	Description	12 Months Ending July 31, 2011
1	***Incentives Paid:***	
2	**Residential Programs**	
3	Residential Lighting & Appliances	214,500
4	Residential Existing Homes	601,742
5	Residential High Efficiency New Homes	1,552,500
6	Residential Refrigerator Recycling	259,630
7	Residential Water Heating	40,000
8	*Residential Sub-total*	*2,668,372*
9	**Commercial Programs**	
10	Commercial Custom Incentive	1,300,251
11	Commercial Prescriptive Incentive	1,028,210
12	*Commercial Sub-total*	*2,328,460*
13	***TOTAL***	**4,996,832**
14	***Program Costs:***	
15	**Residential Programs**	
16	Residential Lighting & Appliances	982,084
17	Residential Existing Homes	1,669,856
18	Residential High Efficiency New Homes	1,085,945
19	Residential Refrigerator Recycling	1,184,797
20	Residential Water Heating	201,278
21	*Residential Sub-total*	*5,123,960*
22	**Commercial Programs**	
23	Commercial Custom Incentive	751,900
24	Commercial Prescriptive Incentive	1,971,300
25	*Commercial Sub-total*	*2,723,200*
26	**Cross-Cutting Program Costs**	
27	Program Management Oversight	300,000
28	Program Tracking Database	400,000
29	Outreach/Education/Training	200,000
30	*Cross-Cutting Sub-total*	*900,000*
31	***Total***	**8,747,160**
32	***Total Incentive and Program Costs:***	
33	Residential Programs	8,242,332
34	Commercial Programs	5,501,660
35	***Total***	**13,743,993**

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
DSM Previously Certified Costs
Projected for 12 Months Ending July 31, 2011

Line No.	Description	12 Months Ending July 31, 2011
1	Residential Power Credits - Single Family	7,000,000
2	Residential Power Credits - Multi Family	2,500,000
3	Residential Weatherization Assistance for Low Income	2,000,000
4	Residential Energy Efficiency (EE) Info	250,000
5	Residential EE Consumer Awareness Campaign	4,400,000
6	***Total***	**16,150,000**

* Note: In the planning phase for Power Credit, the program was designed to break even (costs equal benefits); therefore, there is no additional sum calculated at this time. In any given year, this may vary and any change will be included in future true-ups.

GEORGIA POWER COMPANY

RETAIL REVENUE REQUIREMENT SUMMARY
DSM Additional Sum Calculation
Projected for 12 Months Ending July 31, 2011

Line No.	Description	12 Months Ending July 31, 2011
1	**Residential**	
2	Electric Avoided Costs	19,434,396
3	Program Incentive Costs	2,668,372
4	Program Non-Incentive Costs	5,123,960
5	Cross Cutting Costs	450,000
6	Total Program Costs	8,242,332
7	***Additional Sum***	**-**
8	**Commercial**	
9	Electric Avoided Costs	85,788,952
10	Program Incentive Costs	2,328,460
11	Program Non-Incentive Costs	2,723,200
12	Cross Cutting Costs	450,000
13	Total Program Costs	5,501,660
14	***Additional Sum***	**-**
15	**Total**	
16	Electric Avoided Costs	105,223,348
17	Program Incentive Costs	4,996,832
18	Program Non-Incentive Costs	7,847,160
19	Cross Cutting Costs	900,000
20	Total Program Costs	13,743,993
21	***Total Additional Sum***	**-**

GEORGIA POWER COMPANY
SUMMARY OF PROJECTIONS
TWELVE MONTHS ENDED DECEMBER 31, 2009 AND ENDING JULY 31, 2011
(AMOUNTS IN THOUSANDS)

LINE NO.	DESCRIPTION	ACTUAL PER BOOKS 12/31/2009	ADJUSTMENTS		ACTUAL PRESENT RATES 12/31/2009	NET CHANGE		TEST YEAR AS BUDGETED 07/31/2011	ADJUSTMENTS		TEST YEAR PRESENT RATES 07/31/2011
(1)	(2)	(3) (000)	(4) (000)		(5) (000)	(6) (000)		(7) (000)	(8) (000)		(9) (000)
	OPERATING REVENUES:										
1	Sales of Electricity	7,418,905	(3,022)	A/	7,415,883	476,769	S/	7,892,652	(153,051)	BJ/	7,739,601
2	Other Operating Revenues	272,836	(74,136)	B/	198,700	133,933	T/	332,633	(76,788)	BK/	255,845
3	Total Operating Revenues	7,691,740	(77,158)		7,614,583	610,702		8,225,285	(229,839)		7,995,446
	OPERATING EXPENSES:										
4	Total Operation and Maintenance Expenses	5,189,987	(12,492)	C/	5,177,495	766,435	U/	5,943,931	(1,530)	BL/	5,942,401
5	Depreciation and Amortization Expense	707,491	(10,921)	D/	696,570	84,966	V/	781,536	(2,965)	BM/	778,570
6	Nuclear Decommissioning Expense	3,381	-		3,381	81	W	3,462	(1,776)	BN/	1,686
7	Taxes Other Than Income Taxes	316,532	(2,992)	E/	313,540	25,463	X/	339,003	(172,511)	BO/	166,492
8	Amortization of Investment Tax Credits	(13,722)	-		(13,722)	526	Y/	(13,196)	994	BP/	(12,202)
9	Amortization of Environmental Remediation Rsv.	(604)	-		(604)	604	Z/	-	-		-
10	Amortization / Deferral of Healthcare Costs	-	-		-	-		-	4,165	BQ/	4,165
11	Amortization of Hammond Cooling Tower	-	-		-	-		-	5,415	BR/	5,415
12	Amortization / Deferral of ECCR	-	-		-	(48,682)	AA/	(48,682)	56,269	BS/	7,586
13	Amortization of M&S Inventory - Steam	-	-		-	-		-	1,080	BT/	1,080
14	Amortization / Deferral of DSM	-	-		-	-		-	-		-
15	Amortization of Cost of Removal	(41,396)	(6,300)	F/	(47,696)	(42,304)	AB/	(90,000)	59,175	BU/	(30,825)
16	Federal Income Taxes Payable	224,596	13	G/	224,609	(71,154)	AC/	153,456	1,814	BV/	155,270
17	State Income Taxes Payable	8,547	745	H/	9,292	(40,841)	AD/	(31,549)	1,891	BW/	(29,658)
18	Deferred Income Taxes	187,948	(10,155)	I/	177,793	27,589	AE/	205,382	(67,483)	BX/	137,899
19	Total Operating Expenses	6,582,760	(42,102)		6,540,658	702,684		7,243,342	(115,462)		7,127,880
20	Total Operating Income	1,108,981	(35,056)		1,073,924	(91,981)		981,943	(114,377)		867,566
21	Interest Accretion on ECCR	(8,576)	-		(8,576)	7,665	AF/	(911)	911	BY/	-
22	Interest on Customer Deposits	(3,515)	-		(3,515)	(756)	AG/	(4,271)	-		(4,271)
23	Total Return	1,096,890	(35,056)		1,061,834	(85,072)		976,761	(113,467)		863,295

GEORGIA POWER COMPANY
SUMMARY OF PROJECTIONS
TWELVE MONTHS ENDED DECEMBER 31, 2009 AND ENDING JULY 31, 2011
(AMOUNTS IN THOUSANDS)

LINE NO.	DESCRIPTION	ACTUAL PER BOOKS 12/31/2009	ADJUSTMENTS		ACTUAL PRESENT RATES 12/31/2009	NET CHANGE		TEST YEAR AS BUDGETED 07/31/2011	ADJUSTMENTS		TEST YEAR PRESENT RATES 07/31/2011
	RATE BASE:	13 MONTH AVERAGE PER BOOKS			13 MONTH AVERAGE PRESENT RATES			13 MONTH AVERAGE TEST YEAR AS BUDGETED			13 MONTH AVERAGE TEST YEAR PRESENT RATES
	PLANT-IN-SERVICE:	12/31/2009	ADJUSTMENTS		12/31/2009	NET CHANGE		07/31/2011	ADJUSTMENTS		07/31/2011
20	Electric Plant-in-Service	24,597,611	(295,114)	J/	24,302,497	2,785,278	AH/	27,087,775	(682,832)	BZ/	26,404,942
21	Nuclear Fuel	466,122	-		466,122	58,466	AI/	524,588	-		524,588
22	Electric Plant Held For Future Use	48,151	-		48,151	45,771	AJ/	93,921	-		93,921
23	Plant-in-Service	25,111,883	(295,114)		24,816,769	2,889,515		27,706,284	(682,832)		27,023,452
24	Accum. Prov. for Deprec. And Amortization	9,571,131	(60,165)	K/	9,510,966	766,460	AK/	10,277,426	(71,401)	CA/	10,206,026
25	Accum. Prov. for Nuclear Fuel Amortization	190,956	-		190,956	17,563	AL/	208,518	-		208,518
26	Total Accum. Prov. for Deprec. And Amort.	9,762,087	(60,165)		9,701,922	784,023		10,485,945	(71,401)		10,414,544
27	Net Plant-in-Service	15,349,796	(234,949)		15,114,847	2,105,492		17,220,339	(611,432)		16,608,907
28	Fuel and Materials & Supplies Inventory	1,021,987	(1,088)	L/	1,020,900	(117,098)	AM/	903,802	17,875	CB/	921,677
30	Payables Associated with Capital M&S	(1,051)	-		(1,051)	(26)	AN/	(1,077)	-		(1,077)
31	Minimum Bank Balances, Petty Cash, Prepayments	67,304	-		67,304	19,790	AO/	87,094	-		87,094
32	Prepaid Pension Asset	488,045	-		488,045	28,155	AP/	516,201	-		516,201
33	Customer Deposits	(194,142)	-		(194,142)	(37,046)	AQ/	(231,187)	-		(231,187)
34	Accumulated Interest on Customer Deposits	(25,875)	-		(25,875)	(260)	AR/	(26,135)	-		(26,135)
35	Operating Reserves	(194,630)	-		(194,630)	(14,617)	AS/	(209,247)	6,275	CC/	(202,972)
36	Accumulated Deferred Income Taxes:										-
37	Accelerated Amortization (281)	(216,460)	-		(216,460)	(89,837)	AT/	(306,297)	-		(306,297)
38	Other Property (282)	(2,539,898)	46,328	M/	(2,493,570)	(241,108)	AU/	(2,734,678)	56,036	CD/	(2,678,642)
39	Other (283)	(321,211)	1,155	N/	(320,056)	13,256	AV/	(306,800)	(71,874)	CE/	(378,674)
40	Prepaid (190)	487,775	57	O/	487,832	(47,381)	AW/	440,451	26,907	CF/	467,358
41	Accumulated Deferred Investment Tax Credits	(385)	-		(385)	385	AX/	-	-		-
42	ARO Regulatory Asset/Liability (182 and 230)	24,998	-		24,998	(3,729)	AY/	21,268	-		21,268
43	ARO Liability (254)	(537,128)	438,632	P/	(98,496)	(527,332)	AZ/	(625,828)	506,483	CG/	(119,346)
44	Hammond Cooling Tower Rental	8,625	-		8,625	6,312	BA/	14,937	(2,256)	CH/	12,681
45	Deferred DSM Costs	4,887	-		4,887	(4,887)	BB/	-	-		-
46	Regulatory Asset - Deferred Inc Tax (FAS 158)	-	-		-	-		-	57,935	CI/	57,935
47	Reg Asset - Deferred Costs (182)	-	-		-	-		-	-		-
48	Green Energy Over/Under Recovery	-	-		-	(450)	BC/	(450)	450	CJ/	-
49	M&S Inventory Adjustment - Steam (182)	-	-		-	-		-	4,860	CK/	4,860
50	ECCR Deferred Regulatory Asset (182)	-	-		-	4,311	BD/	4,311	7,269	CL/	11,581
51	ECCR Regulatory Liability	(115,581)	-		(115,581)	107,256	BE/	(8,325)	8,325	CM/	-

GEORGIA POWER COMPANY
SUMMARY OF PROJECTIONS
TWELVE MONTHS ENDED DECEMBER 31, 2009 AND ENDING JULY 31, 2011
(AMOUNTS IN THOUSANDS)

LINE NO.	DESCRIPTION	ACTUAL PER BOOKS 12/31/2009	ADJUSTMENTS		ACTUAL PRESENT RATES 12/31/2009	NET CHANGE		TEST YEAR AS BUDGETED 07/31/2011	ADJUSTMENTS		TEST YEAR PRESENT RATES 07/31/2011
52	Deferred McIntosh C Inspection	14,516	-		14,516	(7,316)	BF/	7,200	-		7,200
53	Reg Liability - Non-ARO Cost of Removal	(102,459)	485	Q/	(101,974)	81,205	BG/	(20,769)	(66,172)	CN/	(86,942)
54	Deferred Nuclear Outage Costs	29,971	-		29,971	(14,337)	BH/	15,634	-		15,634
55	Cash Working Capital	161,367	1,381	R/	162,748	43,157	BI/	205,906	56,353	CO/	262,258
56	TOTAL RATE BASE	13,410,452	252,001		13,662,453	1,303,897		14,966,349	(2,965)		$ 14,963,384
57	RATE OF RETURN	8.18%			7.77%			6.53%			5.77%

HISTORICAL PERIOD ADJUSTMENTS
(COLUMN 5)

FOOTNOTE A/ $ (3,022) Sales of Electricity

This adjustment removes Southern Company Generation & Energy Marketing (SCGEM) wholesale transactions involving purchases and subsequent resale; removes carrying cost on unrecovered fuel balances; and reflects revenue sharing associated with Economy Energy Sales.

Southern Co. Generation & Energy Marketing		$ (3,921)
Unrecovered Fuel Balances - Carrying Costs		(2,258)
Economy Energy Sales - Rev Sharing		3,157
TOTAL		$ (3,022)

FOOTNOTE B/ $ (74,136) Other Operating Revenues

This adjustment removes revenues associated with Unregulated Outdoor Lighting Services, in accordance with the Commission's Order in Docket No. 3936; reflects removal of SCGEM wholesale-related revenue items; removes the wholesale portion of gains associated with emission allowances; and removes revenues associated with FERC Boundary Land Fees (shoreline management billed to lake lot lessees) in accordance with the Commission's Order in Docket No. 25060.

Unregulated Outdoor Lighting Revenues		$ (71,404)
Southern Co. Generation & Energy Marketing		(731)
Wholesale Portion, Gain on Emission Allowance Sales		(30)
FERC Boundary Land Expenses		(1,971)
TOTAL		$ (74,136)

FOOTNOTE C/ $ (12,492) Total Operation and Maintenance Expenses

The adjustment removes SCGEM expenses for wholesale activities; removes Institutional and Goodwill advertising; removes expenses for Unregulated Outdoor Lighting; removes employee stock option expenses; and removes Nuclear Energy Institute (NEI) costs. The adjustment also reflects the impact of Economy Energy revenue sharing; treatment of the Corporate Headquarters as an operating lease; regulatory treatment of Purchased Power Agreement Additional Sums; removes costs of maintaining FERC Boundary Land at Company lakes; and treatment of the Rome Headquarters Building as an operating lease.

Southern Co. Generation & Energy Marketing		$ (4,990)
Institutional & Goodwill Advertising		(3,450)
Unregulated Outdoor Lighting		(10,101)
Stock Option Expenses		(8,270)
Nuclear Energy Institute		(662)
Economy Energy Revenue Sharing		4,209
Corporate Headquarters Lease		8,646
PPA Additional Sums (primarily Arclight & Murray)		3,917
FERC Boundary Land Expenses		(2,133)
Rome Headquarters Building		342
TOTAL		$ (12,492)

FOOTNOTE D/ $ (10,921) Depreciation Expense

These adjustments were made to remove expenses associated with Unregulated Outdoor Lighting Services and to reflect the Rome Headquarters building as a lease.

Unregulated Outdoor Lighting		$ (10,840)
Rome Headquarters Building		(81)
TOTAL		$ (10,921)

FOOTNOTE E/ $ (2,992) Taxes Other Than Income Taxes

This adjustment removes expenses associated with Unregulated Outdoor Lighting Services ($2,992).

FOOTNOTE F/ $ (6,300) Amortization of Cost of Removal

This adjustment was made in the historic period in order to fully reflect the maximum allowable level of Non-ARO Cost of Removal up to the Return on Equity limit specified in the Order associated with Docket 25060.

FOOTNOTE G/ $ 13 Adjustment to Federal Income Taxes Payable

This adjustment results from the treatment of items referenced in FOOTNOTES A/, B/, C/, D/, E/, and F/ above and the interest synchronization adjustment.

Corporate Headquarters Lease		$ (3,994)
Rome Headquarters Building		(111)
Institutional & Goodwill Advertising		1,139
Economy Energy Revenue Sharing		(347)
Nuclear Energy Institute		219
Wholesale Portion, Gain on Emission Allowance Sales		(10)
Southern Co. Generation & Energy Marketing		112
PPA Additional Sums (primarily Arclight & Murray)		(1,293)
Unrecovered Fuel Balances - Carrying Charges		(746)
Internal Revenue Code Section 199 Adjustment		(4,328)
Unregulated Outdoor Lighting		(3,767)
Stock Option Expenses		2,731
FERC Boundary Land Expenses		53
Interest Synchronization		10,355
TOTAL		$ 13

FOOTNOTE H/ $ 745 Adjustment to State Income Taxes Payable

This adjustment results from the treatment of items referenced in FOOTNOTES A/, B/, C/, D/, E/, and F/ above and the interest synchronization adjustment.

Corporate Headquarters Lease		$ (685)
Rome Headquarters Building		(19)
Institutional & Goodwill Advertising		195
Economy Energy Revenue Sharing		(60)
Nuclear Energy Institute		37
Wholesale Portion, Gain on Emission Allowance Sales		(2)
Southern Co. Generation & Energy Marketing		19
PPA Additional Sums (primarily Arclight & Murray)		(222)
Unrecovered Fuel Balances - Carrying Charges		(128)
Unregulated Outdoor Lighting		(642)
Stock Option Expenses		468
FERC Boundary Land Expenses		9
Interest Synchronization		1,775
TOTAL		$ 745

FOOTNOTE I/ $ (10,155) Adjustment to Deferred Income Taxes

This adjustment results from the treatment of items referenced in FOOTNOTES A/, B/, C/, D/, E/, and F/ above.

Unregulated Outdoor Lighting		$ (13,953)
Corporate Headquarters Lease		1,335
Rome Headquarters Building		26
True-up to Non-ARO Cost of Removal		2,437
TOTAL		$ (10,155)

FOOTNOTE J/ $ (295,114) Electric Plant-in-Service

The adjustment to electric-plant-in-service results from the removal of investment associated with Unregulated Outdoor Lighting Services; treatment of the Corporate Headquarters capital lease as an operating lease; and treatment of the Rome Headquarters building as a lease.

Unregulated Outdoor Lighting		$ (225,951)
Corporate Headquarters Lease		(63,954)
Rome Headquarters Building		(5,209)
TOTAL		$ (295,114)

FOOTNOTE K/ $ (60,165) Accumulated Reserve for Depreciation

This adjustment reflects the removal of accumulated depreciation associated with Unregulated Outdoor Lighting Services and the treatment of the Rome Headquarters building as a lease.

Unregulated Outdoor Lighting		$ (59,376)
Rome Headquarters Building		(789)
TOTAL		$ (60,165)

FOOTNOTE L/ $ (1,088) Fuel and Materials & Supplies Inventory

This adjustment removes Materials & Supplies Inventories associated with retail merchandise and with Unregulated Outdoor Lighting Services.

Retail Store Merchandise		$ (431)
Unregulated Outdoor Lighting		(657)
TOTAL		$ (1,088)

FOOTNOTE M/ $ 46,328 Adjustment to Accumulated Deferred Income Taxes – Account 282 – Other Property

This adjustment results from removal of ADIT's associated with CWIP; removal of ADIT's associated with unregulated outdoor lighting; and the treatment of the Rome Headquarters building as a lease.

Accumulated Deferred Income Taxes on CWIP		$ (8,504)
Rome Headquarters Building		1,532
Unregulated Outdoor Lighting		53,300
TOTAL		$ 46,328

FOOTNOTE N/ $ 1,155 Adjustment to Accumulated Deferred Income Taxes – Account 283 – Other

This adjustment results from the treatment of the Rome headquarters as an operating lease.

FOOTNOTE O/ $ 57 Adjustment to Accumulated Deferred Income Taxes – Account 190 – Prepaid

This adjustment results from the treatment of the corporate headquarters as an operating lease rather than a capital lease, and treatment of the Rome headquarters as a lease.

Corporate Headquarters Lease		$ (56)
Rome Headquarters Building		(75)
True-up on Non-ARO Cost of Removal Amortization		(187)
Accumulated Deferred Income Taxes on CWIP		375
TOTAL		$ 57

FOOTNOTE P/ $ 438,632 Asset Retirement Obligation Regulatory Liability

This adjustment reflects the removal of the external nuclear decommissioning reserve from the Asset Retirement Obligation regulatory liability. This amount has been funded externally and as a result should not be applied as a reduction to rate base.

FOOTNOTE Q/ $ 485 Regulatory Liability – Non-ARO Cost of Removal

This adjustment reflects the impact of the true-up to the maximum allowable Non-ARO Cost of Removal amortization for 2009 pursuant to the Order issued in Docket 25060.

FOOTNOTE R/ $ 1,381 Cash Working Capital
This adjustment reflects cash working capital impacts of adjustments noted in preceding footnotes A through Q.

GEORGIA POWER COMPANY

CALCULATION OF ADJUSTED CASH WORKING CAPITAL
ESTIMATED FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2009
(FOOTNOTE R)

Line No.	Description	Amount	Lag (Lead) Days	Dollar Days
(1)	(2)	(3)	(4)	(5)
1	Operating Revenues		39.2	
	Cash Operating Expenses:			
2	Fuels Other Than Nuclear	$2,625,792	(16.5)	$ (43,325,568)
3	Nuclear Fuel Disposal Costs	14,262	(76.6)	(1,092,469)
4	Nuclear Decommissioning	3,381	(258.0)	(872,298)
	Purchased Power:			
5	Purchases-Power Pool (net) *	599,758	0.6	359,855
6	Purchases-Non Power Pool (net) *	247,191	1.1	271,910
7	Other Operating and Maintenance Expenses	1,466,516	(29.8)	(43,702,177)
8	Taxes Other Than Income Taxes	313,540	(157.7)	(49,445,258)
	Current Income Taxes:			
9	Federal	224,609	(37.5)	(8,422,855)
10	State	9,292	(37.5)	(348,453)
11	Interest Expense - Long Term Debt	334,730	(63.4)	(21,221,882)
12	Interest Expense - Preferred Securities	27,325	(45.0)	(1,229,625)
13	Preferred Dividends	2,732	(45.0)	(122,940)
14	Total Cash Operating Expenses	$ 5,869,129	(28.8)	$ (169,151,760)
15	Net Lag Days		10.4	
16	Average Daily Cash Operating Expenses ($5,540,258 / 365)		$ 16,080	
17	Cash Working Capital Before Adjustments ($15,179 X 10.0)		167,232	
18	Adjustment for Sales Tax Collection		(4,484)	
19	Cash Working Capital		$ 162,748	
20	Per Books Cash Working Capital		161,367	
21	Cash Working Capital Adjustment		$ 1,381	

* These amounts include combined credits of $142,033 representing power sales which are credited to retail revenue for regulatory reporting purposes.

TEST PERIOD - NET CHANGE
(COLUMN 6)

FOOTNOTE S/ $ 476,769 Sales of Electricity

The following is an analysis of the increase in Sales of Electricity:

	12 Mos Ended 07/31/2011	12 Mos Ended 12/31/2009	Net Change
Retail Revenues, Base	$ 3,977,249	$ 3,943,859	$ 33,390
Retail Revenues, Fuel	3,388,646	2,968,544	420,102
Total Retail Revenues	$ 7,365,895	$ 6,912,403	$ 453,492
Wholesale Revenues	526,756	506,502	20,255
Impact of "Footnote A"	-	(3,022)	3,022
TOTAL	$ 7,892,652	$ 7,415,883	$ 476,769

The increase in retail base and fuel revenues reflects an expected increase in retail sales in the test period consistent with the Company's energy sales forecast filed in Docket No. 31081. The increase in wholesale revenues is primarily due to increases in block power and economy energy sales, offset partially by a decrease in power pool sales.

FOOTNOTE T/ $ 133,933 Other Operating Revenues

The following is an analysis of the increase in Other Operating Revenues:

	12 Mos Ended 07/31/2011	12 Mos Ended 12/31/2009	Net Change
Forfeited Discounts	$ 16,405	$ 15,793	$ 612
Miscellaneous Service Revenues	123,978	117,499	6,479
Rent from Electric Property	40,346	39,072	1,274
Other Electric Revenues	151,904	100,472	51,432
Impact of FOOTNOTE B/	-	(74,136)	74,136
TOTAL	$ 332,633	$ 198,700	$ 133,933

The increase in Miscellaneous Service Revenues is primarily due to anticipated revenue growth in the unregulated outdoor lighting business. This growth is removed from test period Other Operating Revenues in FOOTNOTE BK/. The increase in Other Electric Revenues is primarily the result of increased Open Access Transmission Tariff (OATT) "point-to-point" and network service revenues.

FOOTNOTE U/ $ 766,435 Operation and Maintenance Expenses

The increase in Operation and Maintenance Expenses is outlined in the explanations provided on the following pages. Compound annual growth rate (CAGR) as shown reflects annualized growth over the 19 months between the historic and test periods.

PROJECTED CHANGES IN OPERATIONS AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDING JULY 31, 2011 AND DECEMBER 31, 2009
(FOOTNOTE U)
($000'S)

TOTAL O&M - PROJECTED CHANGES

FUNCTION	TME 7/31/2011	TME 12/31/2009	NET CHANGE	% CHANGE	% CAGR
Steam Operations, Non-Fuel O&M	$ 466,395	$ 323,144	$ 143,250	44.33%	26.08%
Nuclear Operations, Non-Fuel O&M	201,567	165,969	35,598	21.45%	13.06%
Hydro Operations, Non-Fuel O&M	24,101	18,950	5,151	27.18%	16.40%
CT / Other Operations, Non-Fuel O&M	34,468	35,680	(1,212)	-3.40%	-2.16%
Other Power Supply, Purchased Power Non-Fuel Expenses	451,470	464,675	(13,205)	-2.84%	-1.80%
Transmission O&M	125,653	89,835	35,818	39.87%	23.61%
Distribution O&M	265,426	208,945	56,481	27.03%	16.31%
Customer Accounting O&M	161,964	149,706	12,259	8.19%	5.10%
Customer Service & Information O&M	38,258	33,490	4,768	14.24%	8.77%
Sales Expense O&M	46,147	32,102	14,045	43.75%	25.76%
Administrative & General Expenses	426,959	395,188	31,771	8.04%	5.01%
TOTAL NON-FUEL O&M	$ 2,242,409	$ 1,917,685	$ 324,725	16.82%	10.38%
Steam Fuel Expense	2,338,367	2,014,996	323,371	16.05%	9.86%
Nuclear Fuel Expense	115,535	82,014	33,521	40.87%	24.16%
CT / Other Fuel Expense	500,509	610,795	(110,286)	-18.06%	-11.82%
TOTAL FUEL FOR GENERATION EXPENSE	$ 2,954,411	$ 2,707,805	$ 246,605	9.11%	5.66%
Purchased Power Fuel Expenses	747,110	552,007	195,103	35.34%	21.06%
TOTAL O&M EXPENSES *	$ 5,943,930	$ 5,177,497	$ 766,433	14.80%	9.11%

* Totals may not add due to rounding.

PROJECTED CHANGES IN POWER PRODUCTION EXPENSES
FOR THE TWELVE MONTHS ENDING JULY 31, 2011 AND DECEMBER 31, 2009
(FOOTNOTE U)
($000'S)

STEAM POWER GENERATION

FERC		NET CHANGE	% CHANGE	% CAGR
500	Operation Supervision and Engineering	$ 2,775	24.74%	14.98%
501	Fuel Handling	(1,606)	-17.62%	-11.52%
502	Steam Expenses	25,258	71.39%	40.54%
505	Electric Expenses	(3,284)	-19.90%	-13.08%
506	Miscellaneous Steam Power Expenses	(1,224)	-1.48%	-0.94%
507	Rents	381	633.40%	251.99%
	Total Steam Operations (excl. Fuel)	$ 22,299	14.40%	8.87%

The increase in this category was primarily due to increased material costs associated with environmental control operations, $18,525 (ammonia, limestone, and hydrated lime); decreased gypsum [ash] sales at Plants Bowen and Hammond, $770, which are removed from retail costs and included in the Environmental Compliance Cost Recovery (ECCR) tariff; and normal escalation of labor and materials.

510	Maintenance Supervision and Engineering	$ 4,308	18.33%	11.21%
511	Maintenance of Structures	3,093	14.41%	8.87%
512	Maintenance of Boiler Plant	92,414	100.73%	55.28%
513	Maintenance of Electric Plant	22,915	114.03%	61.70%
514	Maintenance of Miscellaneous Steam Plant	(1,778)	-15.48%	-10.07%
	Total Steam Maintenance	$ 120,951	71.87%	40.78%

In 2009 economic conditions drove the Company's business decisions to forego certain maintenance projects. In 2009, the Company's major planned outage costs were approximately $32 million, over 50% less than actual amounts spent annually in 2007 and 2008. As a result, the increase in this category is primarily the result of planned outage work budgeted in the test period, $57,000.

In addition, the increase in maintenance accounts was also due to normal "baseline" maintenance activities that were, in many situations, curtailed in 2009 for economic reasons. The primary systems or activities associated with these costs were boiler/turbine/generator work, $22,000, and environmental maintenance activities, $20,000 (these costs will be removed from retail expense and recovered through the Environmental Compliance Cost Recovery tariff). Normal ongoing maintenance projects are also budgeted in support of other systems, such as fuel burning and supply equipment, ash handling, air and gas flow systems and switchyard maintenance, $14,000. The remaining difference is associated with common/ancillary equipment and structural maintenance at various plant sites.

	TOTAL STEAM POWER GENERATION EXPENSES (excl. Fuel)	$ 143,250	44.33%	26.08%
501	Fuel Expense	323,371	16.05%	9.86%

The increase in fuel cost is due to an expected increase in generation during the test period (fuel cost is excluded from retail base rates).

	TOTAL STEAM POWER GENERATION EXPENSES (incl. Fuel)	$ 466,621	19.96%	12.18%

PROJECTED CHANGES IN POWER PRODUCTION EXPENSES
FOR THE TWELVE MONTHS ENDING JULY 31, 2011 AND DECEMBER 31, 2009
(FOOTNOTE U)
($000'S)

NUCLEAR POWER GENERATION

FERC		NET CHANGE	% CHANGE	% CAGR
517	Operation Supervision and Engineering	$ 13,895	40.29%	23.84%
519	Coolants and Water	97	13.65%	8.42%
520	Steam Expenses	(328)	-1.47%	-0.93%
523	Electric Expenses	(52)	-100.00%	-100.00%
524	Miscellaneous Nuclear Power Expenses	9,909	23.59%	14.31%
525	Rents	40	663.96%	261.18%
	Total Nuclear Operations (excl. Fuel)	$ 23,561	23.66%	14.36%

The increase in this category is primarily the result of various projects budgeted during the test period (e.g. cooler coil replacements, weld overlays) totaling $13,800; the increase also reflects Vogtle 3 and 4 planned development and implementation of training programs to ensure staff will be available and prepared to begin operations once completed, $5,400; increase in industry dues and fees in anticipation of higher costs for various issues e.g. security and new nuclear (including INPO, NEI, and NRC fees) $2,300 ($618 of NEI fees will be removed through a column adjustment to retail expenses as indicated in Footnote BL/); increases in emergency preparedness fees, normal operating materials and travel and meals, $1,600.

528	Maintenance Supervision and Engineering	$ 1,513	12.08%	7.47%
529	Maintenance of Structures	(809)	-20.48%	-13.48%
530	Maintenance of Reactor Plant Equipment	11,884	43.40%	25.56%
531	Maintenance of Electric Plant	2,825	31.04%	18.62%
532	Maintenance of Miscellaneous Nuclear Plant	(3,386)	-30.23%	-20.34%
	Total Nuclear Maintenance (excl. Outage Levelization)	$ 12,028	18.75%	11.46%

The increase in this category is primarily due to increased contractor support to execute outage scope within a shorter duration, $3,900; material costs for hot and cold leg inspections, $2,500; outage contingency work for unexpected costs during refueling outages (based on historical trends), $2,600; Plant Hatch weld overlay project required to address risks identified during the 2009 refueling outage, $500; and shroud inspections which must be done due to reliability issues, $700.

407	Nuclear Outage Levelization	9	N.A	N.A
	TOTAL NUCLEAR POWER GENERATION EXPENSES (excl. Fuel)	$ 35,598	21.45%	13.06%
518	Fuel Expense	33,521	40.87%	24.16%

The increase in fuel cost is due to an expected increase in nuclear generation during the test period (fuel cost is excluded from retail base rates).

	TOTAL NUCLEAR POWER GENERATION EXPENSES	$ 69,119	27.87%	16.80%

PROJECTED CHANGES IN POWER PRODUCTION EXPENSES
FOR THE TWELVE MONTHS ENDING JULY 31, 2011 AND DECEMBER 31, 2009
(FOOTNOTE U)
($000'S)

HYDRAULIC POWER GENERATION

FERC		NET CHANGE	% CHANGE	% CAGR
535	Operation Supervision and Engineering	$ 547	63.27%	36.29%
536	Water for Power	104	15.95%	9.79%
537	Hydraulic Expenses	2,405	822.89%	306.98%
538	Electric Expenses	470	15.04%	9.25%
539	Miscellaneous Hydro Power Expenses	670	12.57%	7.77%
540	Rents	5	12.46%	7.70%
	Total Hydraulic Operation	$ 4,201	40.79%	24.12%

The increase in this category is primarily a result of increased FERC license required recreation facilities, $288; increased FERC annual operating fees, $121; SCS Hydro Services and Engineering costs including dam safety inspections, FERC interface & compliance monitoring, plant turbine troubleshooting and compliance support, $687; Plant Mitchell labor reallocation to Flint River hydro accounts, $518 (reallocation from steam operations to hydro operations); costs associated with shoreline maintenance which will be removed from retail expenses through a column adjustment as indicated in Footnote BL/, $1,401; Rocky Mountain Project operating fees, $41; headwater benefits, $63; and normal escalation of labor and materials.

541	Maintenance Supervision and Engineering	$ 57	3.72%	2.33%
542	Maintenance of Structures	(201)	-12.85%	-8.32%
543	Maintenance of Reservoirs, Dams, & Waterways	(708)	-61.88%	-45.62%
544	Maintenance of Electric Plant	1,596	42.74%	25.20%
545	Maintenance of Miscellaneous Hydraulic Plant	207	30.18%	18.13%
	Total Hydraulic Maintenance	$ 950	10.98%	6.80%

The increase in this category is primarily the result of engineering services for turbine, generator and ancillary equipment repairs, $255; environmental impact study costs, $100; Plant Mitchell labor reallocation to Flint River hydro accounts, $342 (reallocation from steam maintenance to hydro maintenance); and normal escalation of labor and materials.

	TOTAL HYDRAULIC POWER GENERATION EXPENSES	$ 5,151	27.18%	16.40%

PROJECTED CHANGES IN POWER PRODUCTION EXPENSES
FOR THE TWELVE MONTHS ENDING JULY 31, 2011 AND DECEMBER 31, 2009
(FOOTNOTE U)
($000'S)

OTHER POWER GENERATION

FERC		NET CHANGE	% CHANGE	% CAGR
546	Operation Supervision and Engineering	$ 1,138	78.28%	44.07%
547	Fuel Handling	4	N.A	N.A
548	Generation Expenses	1,590	87.00%	48.49%
549	Miscellaneous Other Power Expenses	1,283	20.76%	12.65%
550	Rents	148	88.62%	49.30%
	Total Other Power Operation (excl. Fuel)	$ 4,162	43.20%	25.46%

Increases in this function are primarily attributable to the impact of the McDonough combined cycle units being included in the budget beginning 2011, $1,500 (these costs are removed from the test period through a column adjustment to retail operating expenses as indicated in Footnote BL/); increased support costs associated with engineering and IT functions, $780; increased labor costs resulting from reallocation of resources to operations, $1,300; and increased materials usage, $344.

551	Maintenance Supervision and Engineering	$ 646	31.90%	19.11%
552	Maintenance of Structures	896	212.46%	105.36%
553	Maintenance of Generating and Electric Equipment	(6,552)	-36.07%	-24.62%
554	Maintenance of Miscellaneous Other Power Generation Plant	(365)	-44.82%	-31.31%
	Total Other Power Maintenance	$ (5,374)	-25.08%	-16.67%

The decrease in this function is due primarily to the impact of a major Hot Gas Path inspection on McIntosh units 10 and 11 in 2009, ($8,836); the next outage for these units is not scheduled until 2012. This reduction is partially offset by the impact of maintenance costs for the new McDonough combined cycle units being budgeted beginning in 2011, $2,047 (these costs are removed from the test period through a column adjustment to retail expense as indicated in Footnote BL/); and normal escalation of labor and materials.

407	Schedule "C" Inspection Deferral / Amortization	-	0.00%	0.00%
	TOTAL OTHER POWER GENERATION EXPENSES (excl. Fuel)	$ (1,212)	-3.40%	-2.16%
547	Fuel Expense	(110,286)	-18.06%	-11.82%

The decrease in fuel cost is due to an expected decrease in generation and fuel hedging costs during the test period (fuel cost is excluded from retail base rates).

	TOTAL OTHER POWER GENERATION EXPENSES	$ (111,498)	-17.25%	-11.27%

PROJECTED CHANGES IN OTHER POWER PRODUCTION EXPENSES
FOR THE TWELVE MONTHS ENDING JULY 31, 2011 AND DECEMBER 31, 2009
(FOOTNOTE U)
($000'S)

PURCHASED POWER / OTHER POWER SUPPLY EXPENSES

FERC		NET CHANGE	% CHANGE	% CAGR
555	Purchased Power (Non-Fuel)	$ (21,315)	-4.88%	-3.11%
556	System Control and Load Dispatching	3,964	52.55%	30.57%
557	Other Expenses	4,146	20.57%	12.54%
	TOTAL PURCHASED POWER / OTHER POWER SUPPLY EXPENSE (excl. Fuel)	$ (13,205)	-2.84%	-1.80%

This decrease is primarily due to the impact of net decreases in non-fuel purchased power costs (primarily related to expiration of certain tolling agreements), ($11,197); to the impact of the 2009 column adjustment to retail expenses associated with Purchase Power Agreement additional sums (a similar adjustment for the test period is indicated in Footnote BL/), ($3,917); and 2009 retail adjustments for Southern Company Generation and Energy Marketing wholesale activities and Economy Energy, ($6,201). These decreases were partially offset by the impact of replacement power insurance refunds (expense credits) in 2009, $2,244 (no refund is expected for the test period); increases in [Generating] Fleet Operations costs, $1,053; increased scheduling, market analysis, and information technology costs supporting wholesale and trading activities, $772 (these costs and Fleet Operations costs are removed from retail expenses through a column adjustment as indicated in Footnote BL/); and the impact of Demand Side Management Power Credit programs, $2,420 (these costs are also removed through column adjustments as indicated in Footnote BL/).

555	Purchased Power (Fuel)	$ 195,103	35.34%	21.06%

The increase in this category is due primarily to increased purchases of energy from the Southern System Power Pool (fuel cost is excluded from retail base rates).

	TOTAL PURCHASED POWER / OTHER POWER SUPPLY	$ 181,898	17.89%	10.95%

PROJECTED CHANGES IN TRANSMISSION EXPENSES
FOR THE TWELVE MONTHS ENDING JULY 31, 2011 AND DECEMBER 31, 2009
(FOOTNOTE U)
($000'S)

TRANSMISSION EXPENSES

FERC		NET CHANGE	% CHANGE	% CAGR
560	Operation Supervision and Engineering	$ 2,517	28.26%	17.02%
561	Load Dispatching	2,524	15.80%	9.71%
562	Station Expenses	845	146.99%	77.01%
563	Overhead Line Expenses	(223)	-29.85%	-20.06%
565	Transmission of Electricity by Others	3,253	-603.71%	NA
566	Miscellaneous Transmission Expenses	1,726	36.07%	21.47%
567	Rents (includes ITS Parity)	4,042	77.40%	43.63%
	Total Transmission Operations	$ 14,684	41.16%	24.32%

The increase in this category is primarily due to increased ITS Parity charges resulting from changes in GPC's ITS load responsibility, $3,684; increased materials and stores expenses, $973; increased NERC/SERC fees and dues, $513, and the impact of a 2009 column adjustment to retail expenses associated with Southern Company Generation and Energy Marketing (a similar adjustment for the test period is indicated in Footnote BL/), $3,757. Additionally, increases in this function were partially due to cost containment efforts in 2009 resulting from economic conditions. Primary areas of increase include Transmission Line and Substation Maintenance, $560; increased Transmission Support, $1,552; increased Transmission Operations Support, $956; and the impact of curtailed Transmission Vegetation and Rights of Way Management costs, $638.

568	Maintenance Supervision and Engineering	$ 3,881	39.65%	23.48%
569	Maintenance of Structures	(163)	-10.10%	-6.50%
570	Maintenance of Station Equipment	4,210	26.58%	16.05%
571	Maintenance of Overhead Lines	13,344	49.83%	29.09%
572	Maintenance of Underground Lines	(20)	-100.00%	-100.00%
573	Maintenance of Miscellaneous Transmission Plant	(117)	-99.72%	-97.56%
	Total Transmission Maintenance	$ 21,134	39.02%	23.13%

The increases in this function were partially due to cost containment efforts in 2009 resulting from economic conditions. Primary areas of increase include Transmission Line and Substation Preventative Maintenance, $14,950 (Line Maintenance, $11,700; Substation Maintenance, $3,250); Transmission Vegetation and Right of Way Management, $3,730; and Transmission Operations Support, $3,250.

	TOTAL TRANSMISSION EXPENSES	$ 35,818	39.87%	23.61%

PROJECTED CHANGES IN DISTRIBUTION EXPENSES
FOR THE TWELVE MONTHS ENDING JULY 31, 2011 AND DECEMBER 31, 2009
(FOOTNOTE U)
($000'S)

DISTRIBUTION EXPENSES

FERC		NET CHANGE	% CHANGE	% CAGR
580	Operation Supervision and Engineering	$ 2,975	31.10%	18.65%
581	Load Dispatching	2,700	17.06%	10.46%
582	Station Expenses	(250)	-12.14%	-7.85%
583	Overhead Line Expenses	1,828	86.63%	48.30%
584	Underground Line Expenses	2,162	27.52%	16.60%
585	Street Lighting and Signal System Expenses	1,347	74.28%	42.03%
586	Meter Expenses	6,628	26.51%	16.01%
587	Customer Installation Expenses	(150)	-5.46%	-3.48%
588	Miscellaneous Distribution Expenses	4,241	20.25%	12.35%
589	Rents	204	6.35%	3.97%
	Total Distribution Operation	$ 21,686	23.79%	14.43%

Increases in this area are partially due to 2009 economic conditions and related cost containment initiatives to alter the schedule and scope of certain ongoing expenses, including Distribution Asset Management (primarily overhead line inspections), $1,298; relamping costs, $632; software licensing fees & enhancements, $792; communications infrastructure costs, $1,600; and other misc expenses such as meals and travel, training, small tools, fleet vehicle maintenance, $5,492. A portion of the increase is attributable to poor economic conditions in 2009 which resulted in curtailed incidental maintenance and meter repair costs, $2,987. A portion of the increase is also due to costs associated with the AMI project, some of which were reclassified from FERC 902 (Meter Reading Expenses) to FERC 586 (Meter Expenses), $3,049; and increased system operations costs resulting from changes associated with Energy Management System (EMS) applications, $1,409. In addition, $1,174 in street lighting and signal systems expenses associated with Unregulated Outdoor Lighting will be removed from retail costs through an adjustment cited in Footnote BL/.

590	Maintenance Supervision and Engineering	$ 4,523	35.09%	20.92%
591	Maintenance of Structures	(482)	-67.97%	-51.28%
592	Maintenance of Station Equipment	926	10.09%	6.26%
593	Maintenance of Overhead Lines	23,881	38.47%	22.82%
594	Maintenance of Underground Lines	1,582	11.02%	6.82%
595	Maintenance of Line Transformers	(138)	-3.76%	-2.39%
596	Maintenance of Street Lighting and Signal Systems	4,034	37.88%	22.49%
597	Maintenance of Meters	13	0.28%	0.18%
598	Maintenance of Miscellaneous Distribution Plant	455	-100.00%	-100.00%
	Total Distribution Maintenance	$ 34,795	29.54%	17.76%

Increases in this area are primarily due to 2009 economic conditions which drove the Company to curtail certain ongoing expenses; costs impacted by poor economic conditions and the Company's resulting cost containment efforts in 2009 were Distribution Vegetation Management, $11,624; Distribution Asset Management expenses (overhead line repairs), $7,960; cable location expenses, $1,489; transmission IT support, $941; and meals and travel, training, and other discretionary expenses, $9,242. A portion of the increase is also attributable to increases in communications infrastructure and services costs, $1,240; and to decreased storm activity and OH trouble restoration in 2009, $1,618. In addition, $4,098 in maintenance of street lighting and signal systems expenses associated with Unregulated Outdoor Lighting will be removed from retail costs through an adjustment cited in Footnote BL/.

	TOTAL DISTRIBUTION EXPENSES	$ 56,481	27.03%	16.31%

PROJECTED CHANGES IN CUSTOMER ACCOUNTS, CUSTOMER SERVICE, & RETAIL MARKETING EXPENSES
FOR THE TWELVE MONTHS ENDING JULY 31, 2011 AND DECEMBER 31, 2009
(FOOTNOTE U)
($000'S)

CUSTOMER ACCOUNTS EXPENSES

FERC		NET CHANGE	% CHANGE	% CAGR
901	Supervision	$ 1,644	47.18%	27.65%
902	Meter Reading Expenses	(5,473)	-16.85%	-11.00%
903	Customer Records and Collections Expenses	12,096	14.29%	8.80%
904	Uncollectible Accounts	3,995	13.78%	8.49%
905	Miscellaneous Customer Accounts Expenses	(3)	-3.04%	-1.93%
	TOTAL CUSTOMER ACCOUNTS EXPENSES	$ 12,259	8.19%	5.10%

The increase in this category is primarily due to 2009 economic conditions which drove the Company to forego certain expenses & system modifications/enhancements in 2009, $1,900; to the impact of reinstatement of merit increases, $1,961; to costs associated with metering system software and contract labor and consulting for the Automater Metering Infrastructure Project (AMI), $1,241; communications services and infrastructure costs, $933; cost for statewide secured deposit services where local offices did not previously have secured deposit pickup, $649; and normal escalation of labor and materials. The increase in uncollectible accounts is attributable to the impact of a collection in 2009 from a prior bankruptcy coupled with projected impacts of poor economic conditions, $3,906.

CUSTOMER SERVICE AND INFORMATION EXPENSES

FERC		NET CHANGE *	% CHANGE	% CAGR
907	Supervision	$ -	N.A.	N.A.
908	Customer Assistance Expenses	5,388	17.17%	10.52%
909	Informational and Instructional Advertising Expenses	261	38.83%	23.02%
910	Miscellaneous Customer Service and Informational Expenses	(882)	-61.78%	-45.53%
	TOTAL CUSTOMER SERVICE AND INFORMATION EXPENSES	$ 4,768	14.24%	8.77%

The increase in this category is primarily a result of costs associated with Demand Side Management (DSM) programs, which the Company has removed from retail cost of service and will recover via separate tariff as indicated in Docket 31082 (see Footnote BL/, which includes removal of $4,643 from Customer Assistance Expenses).

RETAIL MARKETING EXPENSES

FERC		NET CHANGE *	% CHANGE	% CAGR
912	Demonstration and Selling Expenses	14,014	43.69%	25.73%
913	Advertising Expenses	31	126.13%	67.42%
	TOTAL RETAIL MARKETING EXPENSES	$ 14,045	43.75%	25.76%

The increase in this category is primarily due to the impact of Customer Rebate programs (2009 reflected significant underruns in programs including the Commercial and Residential Marathon Water Heater Programs, Existing Residential Market, New Residential Market, Strategic Growth due to economic conditions), $2,777; to increases for wireless communications and marketing support services costs (including organizational structure changes to GPC Energy Efficiency & Sales), $1,713; increased contract labor and services resulting from cost containment efforts in 2009 due to economic conditions, $3,781; and labor costs associated with various demonstration and sales expenses for Outdoor Lighting (the Company proposes to remove $4,653 from FERC 912 as indicated in Footnote BL/).

	TOTAL CUSTOMER ACCOUNTING, SERVICE & SALES	$ 31,072	14.43%	7.39%

PROJECTED CHANGES IN ADMINISTRATIVE & GENERAL EXPENSES
FOR THE TWELVE MONTHS ENDING JULY 31, 2011 AND DECEMBER 31, 2009
(FOOTNOTE U)
($000'S)

ADMINISTRATIVE AND GENERAL EXPENSES

FERC		NET CHANGE	% CHANGE	% CAGR
920	Administrative and General Salaries	$ 10,596	33.75%	20.16%
	This increase is primarily due to removing employee stock option expenses from 2009 pursuant to the Stipulated Agreement in Docket 25060, $5,346; and to normal compensation increases after substantial reductions in 2009, $5,315. A portion of the increase was offset by increased joint owner credits, ($119).			
921	Office Supplies and Expenses	3,783	16.93%	10.38%
	The increase in this account is primarily the result of cost containment efforts in 2009 (2009 actual was $894 less than amounts spent in 2007 and 2008); to increased contract labor associated with building services for the corporate headquarters, $1,164; increases for internal and external training and on-line learning, $1,028; resumption of Town Hall meetings around the state, $450; and to normal escalation.			
922	Administrative Expenses Transferred - Credit	1,620	-58.45%	-42.57%
	The change in this account is due primarily to projected decreases in credits associated with various customer projects.			
923	Outside Services Employed	20,282	15.60%	9.59%
	The increase in this account is due primarily to a net increase in billings from Southern Nuclear (primarily for the Nuclear Development Organization supporting the construction of Vogtle 3 and 4), $7,575; to increased SCS billings primarily associated with the implementation of new general ledger and financial reporting applications and increased IT billings, $4,061; to increased legal fees and expenses, $3,453; to increased contract labor and services, $4,638; and costs associated with Outdoor Lighting which will be removed through a column adjustment as indicated in Footnote BL/, $705.			
924	Property Insurance	7,442	22.27%	13.54%
	The increase in this account is primarily due to a proposed increase in the Environmental Remediation accrual resulting from the identification of additional sites requiring remediation (these costs are removed from the test period through a column adjustment as indicated in footnote BL/, for recovery through the ECCR Tariff), $4,794; to the impact of a nuclear mutual insurance refund in 2009 (expense credit) of $2,104; and escalation of premium costs.			
925	Injuries and Damages	4,757	21.09%	12.85%
	The increase in this account is primarily due to premium increases associated with liability, workers compensation, and fiduciary coverage's, $1,883; increased legal fees and expenses, $1,206; increased safety and health expenses , $438; decreases in budgeted subrogation and third party reimbursements, $767; and escalation.			
926	Employee Pensions and Benefits (incl. 407 Amortization of Deferred OPRB)	(28,437)	-22.98%	-15.20%
	The decrease in this account is primarily due to the impact of severances in 2009 for the Voluntary Attrition Program (VAP), ($30,566).			
928	Regulatory Expenses	832	10.23%	6.35%
	The increase in Regulatory expenses is primarily the result of increases in FERC funding assessments of $760.			
929	Duplicate Charges - Credit	846	-7.82%	-5.01%
	The decrease in this account resulted primarily from the impact of procurement card rebates received from MasterCard in 2009, $447; to a change in occupancy credits associated with the closure of Kilowatt Korner, $194; and to an increase in budgeted costs associated with electronic and media equipment and services, $188.			
930	Miscellaneous General Expenses	15,323	142.58%	75.01%
	The increase in this account is primarily due to the impact of a retail adjustment in 2009 to remove general image advertising from retail expenses as indicated in Footnote C/, $12,114 (comparable costs for the test period will be removed through a column adjustment as indicated in Footnote BL/); to increased costs associated with bank credit lines, $1,675; to increased costs for substance abuse testing, $466; to increased community services costs, $386; to increased board of directors costs, $229; and normal escalation of labor and materials.			
931	Rents	(7,915)	-57.97%	-42.16%
	The increase in this account is primarily due to the impact of a retail adjustment in 2009 for the Corporate Headquarters (capitalized lease treated as an operating lease pursuant to GPSC decision in Docket 3270), ($8,646); and a retail adjustment for the Rome Building (owned property treated as an operating lease pursuant to GPSC decision in Docket 4007), ($342). These impacts were partially offset by the reclassification of rent credits from this account to revenue account 454, $838; and to increased costs of site leases for communications equipment and installations, $279.			
935	Maintenance of General Plant	2,642	20.66%	12.59%
	The increase in this account is primarily due to curtailed contract labor and services resulting from cost containment efforts in 2009 (2009 actual was $2,191 or 14.5% less than the average annual amount spent for maintenance in 2007 and 2008); and to normal escalation of labor and materials.			
	TOTAL ADMINISTRATIVE AND GENERAL EXPENSES	$ 31,771	8.04%	5.01%

FOOTNOTE V/ $ 84,966 Depreciation Expense

The increase in Depreciation Expense is primarily due to the increase in Electric Plant in Service as identified in FOOTNOTE AH/.

FOOTNOTE W/ $ 81 Nuclear Decommissioning Expense

This increase is primarily due to a decrease in the transfer of internal reserves after 2009.

FOOTNOTE X/ $ 25,463 Taxes Other Than Income Taxes

TYPE OF TAX	12 Mos Ending 07/31/2011	12 Mos Ended 12/31/2009	Net Change
Real & Personal Property	$ 128,857	$ 113,317	$ 15,540
Payroll	39,125	44,085	(4,960)
All Other	132	129	3
Franchise Fees	170,889	159,001	11,888
Impact of FOOTNOTE E/	-	(2,992)	2,992
TOTAL	$ 339,003	$ 313,540	$ 25,463

Real & Personal Property taxes are projected to increase as a result of plant additions; Franchise Fees are projected to increase due to an increase in budgeted retail revenues.

FOOTNOTE Y/ $ 526 Amortization of Investment Tax Credits

The increase in this account is due to increased amortization of investment tax credits.

FOOTNOTE Z/ $ 604 Amortization of Environmental Remediation Reserves (Insurance Recoveries)

The increase in this amount reflects the expiration of the amortization period authorized in Docket 25060.

FOOTNOTE AA/ $ (48,682) Amortization of ECCR

The decrease in this amount reflects the expiration of expense levelization authorized in Docket 25060.

FOOTNOTE AB/ $ (42,304) Amortization of Cost of Removal

The decrease in this amount reflects the non-ARO cost of removal amortization authorized in the Commission's 2009 Accounting Order under Docket 25060.

FOOTNOTE AC/ $ (71,154) Federal Income Taxes Payable

The decrease in the Federal Income Tax Provision is due to changes in federal taxable income resulting from changes noted in FOOTNOTES U/ through AB/.

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FOOTNOTE AD/ $ (40,841) State Income Taxes Payable

- The decrease in the State Income Taxes Provision is due to changes in State taxable income and State investment tax credits resulting from changes noted in FOOTNOTES U/ through AB/.

FOOTNOTE AE/ $ 27,589 Deferred Income Taxes

The increase in the net provision for deferred income taxes shown is as follows:

TYPE OF TAX	12 Mos Ending 07/31/2011	12 Mos Ended 12/31/2009	Net Change
Account 281 - Accel. Amortization Property	62,015	60,650	1,365
This adjustment is due primarily to increased timing differences projected in the test period versus the historic period.			
Account 282 - Other Property	43,576	228,631	(185,055)
This adjustment is due primarily to reversal of COR timing differences recorded in the historic period.			
Account 283 - Other	59,953	32,626	27,327
This adjustment is due primarily to increased timing differences projected in the test period versus the historic period.			
Account 190 - Prepaid Income Taxes	39,838	(133,959)	173,797
This adjustment is due primarily to timing differences recorded in the historic period.			
Impact of FOOTNOTE I/	-	(10,155)	10,155
TOTAL	$ 205,382	$ 177,793	$ 27,589

FOOTNOTE AF/ $ 7,665 Interest Accretion on ECCR

The increase in Interest Accretion on ECCR results from timing of deferred ECCR costs.

FOOTNOTE AG/ $ (756) Interest on Customer Deposits

This increase results from increases in Customer Deposits as shown in Footnote AQ/.

FOOTNOTE AH/ $ 2,785,278 Electric-Plant-in-Service

The increase in Electric-Plant-in-Service is due to increases in functional groupings as follows:

Production Plant	$ 1,409,384
Transmission Plant	429,597
Distribution Plant	542,780
General Plant	50,869
Intangible Plant	57,534
Sub-Total	$ 2,490,164
Impact of FOOTNOTE I/	295,114
TOTAL	$ 2,785,278

The increase in Production Plant is primarily due to Clean Air Act compliance, as well as other additions and improvements to various generating plants during the test period.

The increase in Transmission Plant is primarily due to transmission line improvements and construction of new substations and transmission lines.

The increase in Distribution Plant is primarily due to construction of distribution lines for new business, as well as construction, purchase and installation of customer meters, substations, distribution transformers and underground systems which serve new and existing customers.

The increase in General Plant is primarily due to additions in structures, communications equipment, and office furniture and equipment.

The increase in Intangible Plant is primarily due to nuclear work management, condition reporting, and materials systems, software updates associated with transmission and distribution systems, and general ledger and financial reporting system updates.

FOOTNOTE AI/ $ 58,466 Nuclear Fuel

The increase in Nuclear Fuel is primarily due to the expected costs and timing of replacement of existing fuel assemblies.

FOOTNOTE AJ/ $ 45,771 Plant Held for Future Use

The increase in Plant Held for Future Use is primarily due to reclassification of land parcels associated with various transmission and distribution projects (details are provided in MFR A-5).

FOOTNOTE AK/ $ 766,460 Accum. Provision for Deprec. & Amort.

The increase in the Accumulated Provision for Depreciation and Amortization is due to normal depreciation and removal costs, partially offset by retirements and salvage value. Functional breakdown of the increase is as follows:

Production Plant	$ 387,781
Transmission Plant	87,171
Distribution Plant	163,492
General Plant	56,135
Intangible Plant	11,716
Sub-Total	$ 706,295
Impact of FOOTNOTE K/	60,165
TOTAL	$ 766,460

FOOTNOTE AL/ $ 17,563 Accum. Provision, Nuclear Fuel Amort.

This increase is a result of normal fuel amortization.

FOOTNOTE AM/ $ (117,098) Fuel and Materials & Supplies Inventory

The following is an analysis of the increase in Fuel and Materials & Supplies Inventory:

	12 Mos Ending 07/31/2011	12 Mos Ended 12/31/2009	Net Change
Coal, Oil and Gas Inventory	$ 508,500	$ 615,900	$ (107,400)
Materials and Supplies Inventory	371,329	362,557	8,772
Emission Allowance Inventory	23,973	43,531	(19,558)
Impact of FOOTNOTE L/	-	(1,088)	1,088
TOTAL	$ 903,802	$ 1,020,899	$ (117,098)

The decrease in inventories is primarily due to decreases in projected coal inventories. Coal inventory nameplate supply for the test period is consistent with the Commission Order issued in Docket No. 23540. Additional adjustments are made to inventories as indicated in Footnote CB/.

FOOTNOTE AN/ $ (26) Payables Associated with Capital M&S

Decrease due to decrease in materials and supplies inventories.

FOOTNOTE AO/ $ 19,790 Min. Bank Balances, Petty Cash & Prepayments

The following is an analysis of the increase in Minimum Bank Balances, Petty Cash, & Prepayments:

	12 Mos Ending 07/31/2011	12 Mos Ended 12/31/2009	Net Change
Minimum Bank Balances	$ 15,000	$ 13,579	$ 1,421
Petty Cash	91	91	-
Prepayments	72,003	53,634	18,369
TOTAL	$ 87,094	$ 67,304	$ 19,790

The increase in Prepayments is primarily due to an increase in prepaid balances associated with new purchased power agreements.

FOOTNOTE AP/	$ 28,155	Prepaid Pension Asset

The increase is primarily due to projected negative pension expense accruals as a result of market returns on external pension plan assets. This amount represents prepaid future fund contributions.

FOOTNOTE AQ/	$ (37,046)	Customer Deposits

The increase in Customer Deposits is primarily due to applications for new service and existing customers' reconnections.

FOOTNOTE AR/	$ (260)	Accumulated Interest on Customer Deposits

The increase in Accumulated Interest on Customer Deposits is the result of interest on deposits between the historical period and the test period.

FOOTNOTE AS/	$ (14,617)	Operating Reserves

The increase in Operating Reserves is primarily due to increases in Other Post Retirement Benefits liabilities.

FOOTNOTE AT/	$ (89,837)	Accumulated Deferred Income Taxes - Accelerated Amortization - Account 281

The increase in Accumulated Deferred Income Taxes - Accelerated Amortization - Account 281 is primarily due to additional net timing differences created by new additions.

FOOTNOTE AU/	$ (241,108)	Accumulated Deferred Income Taxes- Other Property - Account 282

The increase in Accumulated Deferred Income Taxes - Other Property - Account 282 is primarily due to additional net timing differences created by new additions.

FOOTNOTE AV/	$ 13,256	Accumulated Deferred Income Taxes - Other - Account 283

The decrease in Accumulated Deferred Income Taxes - Other - Account 283 is primarily due to the reduction of timing differences created prior to the test period.

FOOTNOTE AW/	$ (47,381)	Accumulated Deferred Income Taxes - Prepaid - Account 190

The decrease in Accumulated Deferred Income Taxes - Prepaid - Account 190 is primarily due to a decrease in timing differences during the test period.

FOOTNOTE AX/	$ 385	Accumulated Deferred Investment Tax Credits

The decrease in Accumulated Deferred Investment Tax Credits is due to regular amortization of ITC generated in prior years.

FOOTNOTE AY/	$ (3,729)	Asset Retirement Obligation (182 and 230)

The decrease in this amount is primarily due to the impact of additional deferrals associated with Asset Retirement Obligation balances.

FOOTNOTE AZ/	$ (527,332)	Asset Retirement Obligation (254)

The increase in this amount reflects the impact of the Nuclear Decommissioning reserve balance, which is included in "as-budgeted" Asset Retirement Obligation balances.

FOOTNOTE BA/	$ 6,312	Hammond Cooling Tower Rental

The increase in this amount is due to the deferral of costs associated with the Hammond Cooling Tower Rental in accordance with Commission's Order in Docket No. 26794.

FOOTNOTE BB/	$ (4,887)	Deferred DSM Costs

This decrease is due to amortization of costs associated with approved Demand Side Management programs pursuant to the Commission's Order in Docket 25060.

FOOTNOTE BC/	$ (450)	Green Energy Over/Under Recovery

This decrease is due to an over recovery of costs associated with Green Energy programs. This balance is removed from rate base through a column adjustment (see Footnote CJ/).

FOOTNOTE BD/	$ 4,311	ECCR Deferred Regulatory Asset

This increase is due to projected 2010 ECCR costs in accordance with the Commission's Order in Docket 25060.

FOOTNOTE BE/	$ 107,256	ECCR Regulatory Liability

The decrease in this amount is due to amortization of ECCR regulatory liability balances resulting from the levelized 2008 – 2010 costs pursuant to the Commission's Order in Docket 25060.

FOOTNOTE BF/	$ (7,316)	Deferred McIntosh Inspections

This decrease is due to amortization of costs associated with McIntosh "C" inspections pursuant to the Accounting Order issued in conjunction with Docket 18300.

FOOTNOTE BG/	$ 81,205	Regulatory Liability – Cost of Removal

This increase is due to amortization of Non-ARO Cost of Removal pursuant to the 2009 Commission's Order under Docket 25060.

FOOTNOTE BH/	$ (14,337)	Deferred Nuclear Outage Costs

The increase in this amount is due to normal deferral and amortization of outage costs, in accordance with the process outlined in the Accounting Order issued in conjunction with Docket 4007.

FOOTNOTE BI/	$ 43,157	Cash Working Capital

The increase in Cash Working Capital is due to the expense and revenue changes associated with previous footnotes. The following page provides details as to the calculation of amount of the adjustment.

GEORGIA POWER COMPANY

CALCULATION OF ADJUSTED CASH WORKING CAPITAL
ESTIMATED FOR THE TWELVE MONTHS ENDED JULY 31, 2011
(FOOTNOTE BI)

Line No.	Description	Amount	Lag / Lead Days	Dollar Days
(1)	(2)	(3)	(4)	(5)
1	Operating Revenues		38.1	
	Cash Operating Expenses:			
2	Fuels Other Than Nuclear	$ 2,838,876	(16.2)	$ (45,989,796)
3	Nuclear Fuel Disposal Costs	18,787	(75.9)	(1,425,956)
4	Nuclear Decommissioning	3,462	(258.0)	(893,196)
	Purchased Power:			
5	Purchases-Power Pool (net) *	544,974	2.5	1,362,434
6	Purchases-Non Power Pool (net) *	546,765	3.5	1,913,679
7	Other Operating and Maintenance Expenses	1,807,960	(27.9)	(50,442,079)
8	Taxes Other Than Income Taxes	339,003	(149.5)	(50,680,915)
	Current Income Taxes:			
9	Federal	153,456	(37.5)	(5,754,597)
10	State	(31,549)	(37.5)	1,183,092
11	Interest Expense - Long Term Debt	362,186	(64.4)	(23,324,778)
12	Interest Expense - Preferred Securities	32,926	(45.0)	(1,481,670)
13	Preferred Dividends	2,993	(45.0)	(134,685)
14	Total Cash Operating Expenses	$ 6,619,839	(26.5)	$ (175,668,467)
15	Net Lag Days		11.6	
16	Average Daily Cash Operating Expenses ($6,180,458 / 365)		$ 18,137	
17	Cash Working Capital Before Adjustments ($16,933 X 6.3)		$ 210,389	
18	Adjustment for Sales Tax Collection		(4,484)	
19	Cash Working Capital		$ 205,906	
20	Cash Working Capital (present rates)		162,748	
21	Cash Working Capital Adjustment		$ 43,157	

* These amounts include combined credits of $71,034 representing power sales which are credited to retail revenue for regulatory reporting purposes.

TEST PERIOD ADJUSTMENTS
(COLUMN 9)

FOOTNOTE BJ/ $ (153,051) Sales of Electricity

This adjustment reflects revenue sharing associated with Economy Energy Sales; removes Southern Company Generation & Energy Marketing (SCGEM) wholesale transactions involving purchases and subsequent resale; budget correction for removal of revenues to be recovered through the DSM tariff; removes carrying costs on unrecovered fuel balances; and removes revenues equal to the amount of Municipal Franchise Fees, which are recovered through a separate tariff as established in Docket 25060.

Economy Energy Sales - Revenue Sharing		$ 3,416
Southern Co. Generation & Energy Marketing		2,596
Budget Corrections - DSM revenues		(2,403)
Unrecovered Fuel Balances - Carrying Costs		(4,712)
Municipal Franchise Fees		(151,947)
TOTAL		$ (153,051)

FOOTNOTE BK/ $ (76,788) Other Operating Revenues

This adjustment removes revenues associated with Unregulated Outdoor Lighting in accordance with the Commission's Order in Docket No. 3936; reflects the impact of revenue sharing for wireless co-location; adjusts municipal franchise fees for unregulated outdoor lighting revenues; and removes revenues associated with fees charged to lake lot lessees, as established in Docket 25060.

Unregulated Outdoor Lighting		$ (77,582)
Wireless Co-Location Revenues		(118)
Municipal Franchise Fees		1,794
FERC Boundary Land Fees		(881)
TOTAL		$ (76,788)

FOOTNOTE BL/ $ (1,530) Total Operation and Maintenance Expenses

The adjustment reflects treatment of the Corporate Headquarters as an operating lease; treatment of the Rome Headquarters Building as an operating lease; removes Institutional and Goodwill advertising; reflects the impact of Economy Energy revenue sharing; removes expenses for the Nuclear Energy Institute (NEI); reflects delay in commercial operation of the McDonough combined cycle units in accordance with the Commission's Order in Docket No. 24506; reflects retirement of McDonough steam units; removes SCGEM expenses for wholesale activities; reflects reclassification of membership fees below the line; removes expenses for Unregulated Outdoor Lighting Services; reflects normalization of accruals for storm damages and environmental remediation; regulatory treatment of Purchased Power Agreement Additional Sums; removes marketing costs to be recovered through separate Demand Side Management (DSM) tariffs; includes estimated Commission consulting fees to be paid by the Company; and removes costs of maintaining FERC Boundary Land at Company lakes.

Corporate Headquarters Lease		$ 8,646
Rome Headquarters Building		342
Institutional & Goodwill Advertising		(11,902)
Economy Energy Sales - Revenue Sharing		4,555
Nuclear Energy Institute Fees		(723)
McDonough Combined Cycle Delay		8,936
McDonough Steam Retirement		3,261
Southern Co. Generation & Energy Marketing		(3,410)
Budget Corrections - Membership Fees & Dues		(56)
Unregulated Outdoor Lighting		(12,409)
Regulatory Accruals Adjustment		3,002
Purchased Power Agreement Additional Sums		7,968
Marketing O&M Adjustment		(8,938)
Georgia Public Service Commission Consulting Fees		600
FERC Boundary Land Expenses		(1,401)
TOTAL		$ (1,530)

FOOTNOTE BM/ $ (2,965) Depreciation Expense

These adjustments were made to reflect the Rome Headquarters building as a lease; reflect the delay of commercial operation for the McDonough combined cycle units; reflect the impact of proposed new depreciation rates; reflect impact of depreciation on budget correction for transmission plant in service; correct budgeted depreciation expense for Plant McDonough transmission investment; and remove expenses associated with Unregulated Outdoor Lighting.

Rome Headquarters Building		$ (92)
McDonough Combined Cycle Delay		(7,430)
Depreciation Study Update		18,814
Budget Corrections		(1,366)
McDonough Transmission Interconnection		377
Unregulated Outdoor Lighting		(13,268)
TOTAL		$ (2,965)

FOOTNOTE BN/ $ (1,776) Nuclear Decommissioning Expense

This adjustment reduces the nuclear decommissioning accrual to the level necessary to fund the NRC minimum exclusive of site restoration costs. This is consistent with the Commission's Order in Docket 25060.

FOOTNOTE BO/ $ (172,511) Taxes Other than Income Taxes

This adjustment removes budgeted Municipal Franchise Fees (MFF) to be recovered through a separate MFF tariff, and also removes costs associated with Outdoor Lighting Services in accordance with the Commission's Order issued in Docket 3936.

FOOTNOTE BP/ $ 994 Amortization of Investment Tax Credits

This adjustment results from changes associated with the Depreciation Study and life extension adjustments related to changes in asset life spans.

FOOTNOTE BQ/ $ 4,165 Amortization of Healthcare Costs

This adjustment results from changes in projected tax impacts on the Company's medical plans resulting from new healthcare legislation proposed to be amortized over the 12 year average remaining employee service life.

FOOTNOTE BR/ $ 5,415 Amortization of Hammond Cooling Tower Rental

This adjustment reflects proposed three year amortization of deferred costs associated with the Hammond Cooling Tower Rental in accordance with the Commission's Order in Docket No. 26794.

FOOTNOTE BS/ $ 56,269 Amortization of ECCR

This adjustment reflects the difference between the amortization associated with the levelized ECCR costs in accordance with the Commission's Order in Docket No. 25060 and proposed three year amortization of additional deferred 2010 ECCR costs.

FOOTNOTE BT/ $ 1,080 Amortization of M&S Inventory - Steam

This adjustment reflects deferral and proposed five year amortization of materials and supplies adjustments associated with the retirement of steam units at Plant McDonough.

FOOTNOTE BU/ $ 59,175 Amortization of Cost of Removal

This adjustment reflects the difference between the 2010 amortization authorized in Docket No. 25060 and the Company's proposed three year amortization of the unused 2009 amounts as well as additional proposed deferred non-ARO costs of removal.

FOOTNOTE BV/ $ 1,814 Adjustment to Federal Income Taxes Payable

This adjustment results from the treatment of items referenced in FOOTNOTES BL/ through BU/ and the interest synchronization adjustment.

Corporate Headquarters Lease		$ (3,135)
Rome Headquarters Building		(113)
Institutional & Goodwill Advertising		3,930
Economy Energy Sales - Revenue Sharing		(376)
Nuclear Energy Institute Fees		239
McDonough Combined Cycle Delay		1,915
McDonough Steam Retirement		(1,431)
Nuclear Decommissioning Accrual Adjustment		586
Southern Co. Generation & Energy Marketing		1,983
Budget Corrections		359
McDonough Transmission Interconnection		(231)
Unregulated Outdoor Lighting		(9,591)
Purchased Power Agreement Additional Sums		(2,631)
Unrecovered Fuel Balances - Carrying Costs		(1,556)
Internal Revenue Code - Section 199 Adjustment		(7,033)
Marketing O&M Adjustment		2,951
Wireless Co-Location Revenues		(39)
Georgia Public Commission Consulting Fees		(198)
Municipal Franchise Fees		6,254
FERC Boundary Land Expenses		171
Interest Synchronization		9,760
TOTAL		$ 1,814

FOOTNOTE BW/ $1,891 Adjustment to State Income Taxes Payable

This adjustment results from the treatment of items referenced in FOOTNOTES BL/ through BU/ and the interest synchronization adjustment.

Corporate Headquarters Lease		$ (535)
Rome Headquarters Building		(19)
Institutional & Goodwill Advertising		674
Economy Energy Sales - Revenue Sharing		(64)
Nuclear Energy Institute Fees		41
McDonough Combined Cycle Delay		313
McDonough Steam Retirement		(246)
Nuclear Decommissioning Accrual Adjustment		101
Southern Co. Generation & Energy Marketing		340
Budget Corrections		62
McDonough Transmission Interconnection		(39)
Unregulated Outdoor Lighting		(1,259)
Purchased Power Agreement Additional Sums		(451)
Unrecovered Fuel Balances - Carrying Costs		(267)
Marketing O&M Adjustment		506
Wireless Co-Location Revenues		(7)
Georgia Public Commission Consulting Fees		(34)
Municipal Franchise Fees		1,073
FERC Boundary Land Expenses		29
Interest Synchronization		1,673
TOTAL		$ 1,891

FOOTNOTE BX/ $ (67,483) Adjustment to Deferred Income Taxes

This adjustment results from the treatment of items referenced in FOOTNOTES BL/ through BU/ and the interest synchronization adjustment.

Corporate Headquarters Lease		$ 326
Rome Headquarters Building		33
ECCR Levelization Adjustment		(18,830)
ECCR Deferral / Amortization		(3,735)
McDonough Combined Cycle Delay		(2,939)
McDonough Steam Retirement		(2)
Depreciation Study Update		(6,803)
Cost of Removal Amortization		(34,811)
Unamortized Cost of Removal Adjustment		11,923
McDonough Transmission Interconnection		125
Healthcare Legislation Tax Adjustment		(1,611)
Unregulated Outdoor Lighting		(7,904)
Regulatory Accruals Adjustment		(3,255)
TOTAL		$ (67,483)

FOOTNOTE BY/ $ 911 Interest Accretion on ECCR

This adjustment reflects removal of interest accretion on existing deferred ECCR balances for the period July through December, 2010.

FOOTNOTE BZ/ $ (682,832) Electric Plant-in-Service

The adjustment to electric-plant-in-service results from removal of investment associated with treatment of the Corporate Headquarters capital lease as an operating lease; from the treatment of the Rome Headquarters building as an operating lease; correction of budgeted plant closures associated with contributions in aid of construction; delayed in-service dates of McDonough Combined Cycle units; McDonough transmission interconnection facilities in-service dates; and removal of investment associated with Unregulated Outdoor Lighting.

Corporate Headquarters Lease		$ (58,126)
Rome Headquarters Building		(5,209)
Budget Corrections		(48,587)
McDonough Combined Cycle Delay		(314,892)
McDonough Transmission Interconnection		14,453
Unregulated Outdoor Lighting		(270,472)
TOTAL		$ (682,832)

FOOTNOTE CA/ $ (71,401) Accumulated Reserve for Depreciation

These adjustments remove accumulated reserve associated with Unregulated Outdoor Lighting; reflect delay of commercial operation for the McDonough combined cycle units; correction of depreciation associated with plant closures adjustment noted in Footnote BZ/ above; reflect the Rome Headquarters building as a lease; reflect the impact of proposed new depreciation rates; and correct budgeted accumulated reserve for Plant McDonough transmission investment.

Rome Headquarters Building		$ (926)
McDonough Combined Cycle Delay		(1,501)
Depreciation Study Update		9,924
Budget Correction		(961)
McDonough Transmission Interconnection		397
Unregulated Outdoor Lighting		(78,334)
TOTAL		$ (71,401)

FOOTNOTE CB/ $17,875 Fuel and Materials & Supplies Inventory

This adjustment reflects budget corrections associated with coal, gas, and emissions inventories; and removal of inventories associated with Unregulated Outdoor Lighting.

Coal Inventories		$ 30,908
Gas Inventories		(10,198)
Emission allowance inventories		(2,151)
Unregulated Outdoor Lighting		(684)
TOTAL		$ 17,875

FOOTNOTE CC/ $ 6,275 Operating Reserves

This adjustment adjusts operating reserves to normalize the impact of proposed changes in regulatory accruals (Storm Damage Reserves, Environmental Remediation as identified in FOOTNOTE BL/.

FOOTNOTE CD/ $ 56,036 Adjustment to Accumulated Deferred Income Taxes – Account 282 – Other Property

This adjustment results primarily from removal of ADITs associated with unregulated outdoor lighting, offset partially by the impact of including ADITs on CWIP balances.

FOOTNOTE CE/ $ (71,874) Adjustment to Accumulated Deferred Income Taxes – Account 283 – Other

This adjustment results primarily from addition of ADITs associated with additional ECCR deferrals, budget correction, regulatory accruals, and the impact on ADITs of current healthcare legislation.

FOOTNOTE CF/ $ 26,907 Adjustment to Accumulated Deferred Income Taxes – Account 190 – Prepaid

This adjustment results primarily from the impact of ADITs associated with proposed additional non-ARO cost of removal deferrals.

FOOTNOTE CG/ $ 506,483 Asset Retirement Obligation Regulatory Liability

This adjustment reflects the removal of the external nuclear decommissioning reserve from the Asset Retirement Obligation regulatory liability. This amount has been funded externally and as a result should not be applied as a reduction to rate base.

FOOTNOTE CH/ $ (2,256) Hammond Cooling Tower Rental

This adjustment reflects proposed amortization of deferred costs associated with the Hammond Cooling Tower Rental as noted in FOOTNOTE BR/.

FOOTNOTE CI/ $ 57,935 Reg. Asset – Deferred Income Tax (FAS 158)

This adjustment reflects the expected tax impacts of current healthcare legislation.

FOOTNOTE CJ/ $450 Green Energy Over/Under Recovery

This adjustment reflects a budget correction associated with Green Energy.

FOOTNOTE CK/ $ 4,860 Materials & Supplies Inventory Adjustment - Steam

This adjustment reflects proposed deferral and subsequent amortization of materials and supplies associated with Plant McDonough as noted in FOOTNOTE BT/.

FOOTNOTE CL/ $ 7,269 ECCR Deferred Regulatory Asset

This adjustment reflects deferral of 2010 ECCR costs pursuant to the Commission's Order in conjunction with Docket 25060, amortization noted in FOOTNOTE BS/; and the impact of a budget correction to ECCR deferrals.

FOOTNOTE CM/ $ 8,325 ECCR Regulatory Liability

This adjustment reflects removal of unamortized ECCR regulatory liabilities pursuant to the Order issued in Docket 25060, for recovery through a separate ECCR tariff.

FOOTNOTE CN/ $ (66,172) Regulatory Liability – Non-ARO Cost of Removal

This adjustment reflects the adjusted Non-ARO Costs of Removal amortization, as noted in FOOTNOTE BU/.

FOOTNOTE CO/ $ 56,353 Cash Working Capital Adjustment

This adjustment reflects the effect on cash working capital due to the above adjustments. The following page provides details associated with the calculation of this adjustment.

GEORGIA POWER COMPANY

CALCULATION OF ADJUSTED CASH WORKING CAPITAL
ESTIMATED FOR THE TWELVE MONTHS ENDED JULY 31, 2011
(FOOTNOTE CN)

Line No.	Description	Amount	Lag / Lead Days	Dollar Days
(1)	(2)	(3)	(4)	(5)
1	Operating Revenues		38.1	
	Cash Operating Expenses:			
2	Fuels Other Than Nuclear	$ 2,838,876	(16.2)	$ (45,989,796)
3	Nuclear Fuel Disposal Costs	18,787	(75.9)	(1,425,956)
4	Nuclear Decommissioning	1,686	(258.0)	(434,988)
	Purchased Power:			
5	Purchases-Power Pool (net) *	561,717	2.5	1,404,293
6	Purchases-Non Power Pool (net) *	559,288	3.5	1,957,510
7	Other Operating and Maintenance Expenses	1,777,164	(27.9)	(49,582,865)
8	Taxes Other Than Income Taxes	166,492	(149.5)	(24,890,519)
	Current Income Taxes:			
9	Federal	155,270	(37.5)	(5,822,622)
10	State	(29,658)	(37.5)	1,112,180
11	Interest Expense - Long Term Debt	362,114	(64.4)	(23,320,142)
12	Interest Expense - Preferred Securities	32,919	(45.0)	(1,481,355)
13	Preferred Dividends	2,993	(45.0)	(134,685)
14	Total Cash Operating Expenses	$ 6,447,649	(23.0)	$ (148,608,945)
15	Net Lag Days		15.1	
16	Average Daily Cash Operating Expenses ($6,440,769 / 365)		$ 17,665	
17	Cash Working Capital Before Adjustments ($17,646 x 15.1)		$ 266,742	
18	Adjustment for Sales Tax Collection		(4,484)	
19	Adjusted Cash Working Capital		$ 262,258	
20	Per Books Cash Working Capital		205,906	
21	Adjusted Cash Working Capital		$ 56,353	

* These amounts include combined credits of $71,034 representing power sales which are credited to retail revenue for regulatory reporting purposes.