REBUTTAL TESTIMONY OF
ANN P. DAISS, ROBERT B. MORRIS, GREGORY N. ROBERTS
AND STEVEN M. FETTER
ON BEHALF OF GEORGIA POWER COMPANY
GPSC DOCKET NO. 31958

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

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

Robert B. Morris. I am the Assistant Comptroller and Assistant Corporate Secretary for Georgia Power. My business address is 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

Gregory N. Roberts. I am the Director, Pricing and Rates, Georgia Power Company. My business address is 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

My name is Steven M. Fetter. I am President of Regulation UnFettered. My business address is 1489 W. Warm Springs Rd., Suite 110, Henderson, Nevada 89014.

Q. MS. DAISS, MR. MORRIS, AND MR. ROBERTS: DID YOU PRESENT DIRECT TESTIMONY AND EXHIBITS ON BEHALF OF GEORGIA POWER IN THIS PROCEEDING?

A. Yes.

Q. MR. FETTER, PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated with high honors from the University of Michigan with an A.B. in Communications in 1974. I graduated from the University of Michigan Law School with a J.D. in 1979. I currently am President of Regulation UnFettered, a utility advisory firm I started in April 2002 to use my financial, regulatory, legislative, and legal expertise to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. My clients include investor-owned and municipal electric, natural gas and water utilities, state public utility commissions and consumer advocates, non-utility energy suppliers, international financial services and consulting firms, and investors. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London, from October 1993 until April 2002. At Fitch I was Group Head and Managing Director of the Global Power Group within Fitch. In that role, I served as group manager of the combined 18-person New York and Chicago utility team. I was originally hired to interpret the impact of regulatory and legislative developments on utility credit ratings, a responsibility I continued to have throughout my tenure at the rating agency. Prior to that, I served as Chairman of the Michigan Public Service Commission ("Michigan PSC"). My full educational and professional background is presented in Rebuttal Exhibit 1.

Q. HOW DOES YOUR EXPERIENCE RELATE TO YOUR TESTIMONY IN THIS PROCEEDING?

A. My experience as a Commissioner on the Michigan PSC and my subsequent professional experience analyzing the U.S. electric and natural gas sectors – in jurisdictions involved in restructuring activity as well as those still following a traditional regulated path – have given me solid insight into the importance of a regulator's role in setting rates and also in determining appropriate terms and conditions of service for regulated utilities. These are among the factors that enter into the process of utility credit analysis and formulation of individual company credit ratings. It is undeniable that a utility's credit ratings significantly affect the ability of a utility to raise capital on a timely basis and upon reasonable terms.

Q. HAVE YOU PREVIOUSLY GIVEN TESTIMONY BEFORE REGULATORY AND LEGISLATIVE BODIES?

A. Since 1990, I have testified on numerous occasions before a variety of public bodies including the U.S. Senate, the U.S. House of Representatives, the Federal Energy Regulatory Commission, federal district and bankruptcy courts, and various state legislative, judicial, and regulatory bodies. I have previously testified before the Georgia Public Service Commission ("Commission") on behalf of Georgia Power in Docket Nos. 18300 and 27800.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of our testimony is to support the Settlement Agreement among the stipulating parties and to rebut positions of parties who have not yet signed the Settlement Agreement. Ms. Daiss and Mr. Morris discuss the overall Alternate Rate Plan and revenue requirements included in the Settlement Agreement, Mr. Fetter provides information on the impact of the Settlement Agreement on the Company's ability to attract capital, and Mr. Roberts addresses rate design and remaining issues.

Q. WHO ARE THE PARTIES CONSENTING TO THE SETTLEMENT AGREEMENT?

A. The stipulating parties include the Company and the Commission Public Interest Advocacy Staff ("PIA Staff") and the Commercial Group[1] (collectively the "Stipulating Parties"). The fact that more parties have not joined in this Settlement Agreement should not be taken as an indication that it doesn't represent their views. The Settlement Agreement was not finalized between the

[1] The Commercial Group has verbally agreed to the Settlement.

PIA Staff and the Company until the evening before this testimony was due to be filed. We hope, and expect, that more parties will sign the Settlement Agreement by the time the hearings are held, especially since there are numerous customer benefits included in it, as explained in more detail later in this testimony.

Q. WHAT ARE THE MAJOR COMPONENTS OF THE PROPOSED SETTLEMENT AGREEMENT?

A. The Settlement Agreement is contained in Rebuttal Exhibit 2. The main components of the Settlement Agreement are as follows:

- The Alternate Rate Plan ("ARP") will be in effect from January 1, 2011 and through December 31, 2013.

- Effective January 1, 2011, the Company would increase its traditional base rate tariffs by $347.201 million.

- The Company's retail return on equity ("ROE") will be set at 11.15 percent with a range between 10.25 and 12.25 percent. The Company will not file a general rate case unless earnings are projected to be less than 10.25 percent. Two-thirds of any earnings above 12.25 percent would be directly refunded to customers, with the remaining one-third retained by the Company. There would be no recovery of any shortfall below 10.25 percent on an actual basis.

- If, at any time during the term of the ARP, the Company projects that its retail earnings will be lower than 10.25 percent for any calendar year, the Company may petition the Commission for the implementation of an Interim Cost Recovery ("ICR") tariff which would be used to adjust the Company's earnings back to 10.25 percent return on equity. The Commission would have 90 days to rule on the Company's request. The ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Commission chooses not to implement the ICR, the Company may file a full rate case.

- The Company is required to file its next base rate case by July 1, 2013.

- The Company will continue the Environmental Compliance Cost Recovery ("ECCR") tariff and will increase it effective January 1, 2011, to collect the levelized annual revenue requirement of $167.815 million for the three year period ending December 31, 2013.

- The Company will be allowed to collect the costs of certain Demand Side Management ("DSM") programs, as specified in the latest DSM Certification and Integrated Resource Plan ("IRP") order, using the DSM tariffs. Effective January 1, 2011, the Company may collect an additional $31.614 million through the DSM tariffs. Effective January 1, 2012, the Company may collect an additional $16.735 million through the DSM tariffs. Effective January 1, 2013, the Company may collect an additional $17.891 million through the DSM tariffs.

- Effective April 1, 2012, the Company's traditional base rate tariffs shall be adjusted to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Commission for Plant McDonough Units 4 and 5 for the period from commercial operation through December 31, 2013.

- Effective January 1, 2013, the Company's traditional base rate tariffs shall be adjusted to recover the 2013 annual revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Commission for

Plant McDonough Unit 6 for the period from commercial operation through December 31, 2013.

- The Company will continue to collect municipal franchise fees ("MFF") through the separate base rate MFF-1 tariff. The Company may collect 2.16 percent of the Company's total revenues, or approximately $15.7 million, beginning January 1, 2011. This tariff will adjust as the Company's total revenues change under the ARP and any future fuel changes, in addition to when new cities enter into new franchise agreements, to collect the franchise fees incurred by the Company pursuant to the Commission's Orders in Docket Nos. 21112 and 25060.

Q. WHY SHOULD THIS RATE CASE BE RESOLVED ON THE BASIS OF THIS SETTLEMENT AGREEMENT?

The Stipulating Parties agree that the Settlement Agreement, taken in its entirety, is the best method to allow the Company to recover its costs in a manner that supports its continued ability to provide safe, reliable and cost-effective electric service. Specifically, the Settlement will allow the continuation of the benefits provided by prior three year rate plans including: (1) stable, predictable rates for our customers over the next three years, (2) continued access to the capital markets at competitive rates which will allow Georgia Power to build the infrastructure we need to serve our customers and comply with environmental regulations, (3) appropriate cost recovery to maintain the outstanding customer service that is a hallmark of our Company, (4) a sharing mechanism that allows customers the opportunity to share in the earnings of the Company, and (5) a mechanism by which the Company may seek expedited rate relief in the event earnings are below the allowed ROE range as a potential alternative to filing a traditional rate case.

The Settlement Agreement represents the collaborative agreement of a diverse set of parties and offers a fair and reasonable resolution to the issues in these proceedings. While not all parties in this case have yet signed the Settlement Agreement, the testimony and concerns of all parties were considered and balanced, and many are adopted in this Settlement Agreement. This form of incentive regulation is consistent with the rate plans the Commission has approved in the Company's last five rate cases, modified to acknowledge the rising cost environment we currently face. While previous three year plans have generally levelized rate increases in the first year of the plan, this ARP includes additional increases during the term to recover the costs of certified capacity coming into service, additional DSM costs, and additional franchise fee costs. Timely recovery of these costs was necessary for the Company to agree to into a multi-year plan. The Settlement Agreement provides customers with rate stability. Unless the Company's earnings are projected to drop below the earnings band, the Settlement Agreement prohibits Georgia Power from filing for a rate increase until July 1, 2013. However, under a traditional rate case order, the Company would be able to file another rate case whenever it deemed appropriate. The Stipulating Parties agree that distinction is of particular importance in light of the current economy.

This case has called for difficult decision making not only by the Commission, but by the Stipulating Parties. No party got everything that they wanted. Major components of the Company's original proposal are missing from this plan, and the Company has agreed to an ROE 80 basis points less than it requested. The Company has agreed to a number of revenue requirement reductions, detailed below, as well. While each Stipulating Party may disagree with the resolution of any particular item, when taken together, the collective balance is fair to all. There may be parties who would prefer that this Settlement Agreement contain, or not contain, something -- often some particular single issue of interest -- and who would sign if "only" that change were made. The Stipulating Parties, who did see the overall balance, have overlooked the single issues for the good of the overall outcome. For that reason, this is a fair outcome agreed to by the Stipulating Parties.

We also believe that the Commission's adoption of the Settlement Agreement will preserve investors' perceptions of Georgia as a stable regulatory environment, the importance of which cannot be overstated at this time. That perception has allowed us to remain a financially strong company and directly affects our ability to provide low rates and high customer satisfaction.

For all of these reasons, this Settlement Agreement should be adopted by this Commission as the resolution of this case.

<u>Return on Equity and the Cost of Capital</u>

Q. WHY DO YOU BELIEVE THAT THE 11.15 PERCENT ROE CONTAINED IN THE SETTLEMENT AGREEMENT IS A REASONABLE OUTCOME?

A. An 11.15 percent ROE is a reasonable compromise for a number of reasons. First, the stipulated ROE appropriately takes into account the Company's large capital program, which was acknowledged by PIA Staff witness David C. Parcell as a relevant factor in determining an appropriate ROE. (Tr. 1112) Second, the stipulated ROE is a fair compromise between the recommendations of Mr. Parcell and the Company's cost of capital witness, Dr. James H. Vander Weide. Third, the stipulated ROE demonstrates to the financial community a level of regulatory continuity that, as discussed below, is critical in terms of the investment decisions made in the marketplace and also the Company's credit ratings. Finally, the stipulated ROE represents one portion of a Stipulation achieved between the Stipulating Parties through a fair and balanced negotiation process and is reasonable in light of the overall compromise achieved in the Stipulation.

It is true that 11.15 percent set point for ROE is less than the ROE set in the Company's 2007 base rate case. It's also true that even PIA Staff's expert Mr. Parcell noted that the Company's cost of equity, and allowed averages, have increased since the Company's last case. (Tr.1149; 1163) However, we believe that these are difficult economic times and that an authorized ROE of 11.15 percent return with a band of 10.25 percent to 12.25 percent, as was set in the last case, appropriately balances the interests of the Company and customers. We believe that an 11.15 percent return should allow the Company to maintain its credit ratings and continue to access capital markets in order to secure necessary financing for the Company's ongoing construction projects.

Q. CAN YOU PROVIDE A BRIEF DISCUSSION ON WHY CREDIT RATINGS ARE IMPORTANT FOR REGULATED UTILITIES AND THEIR CUSTOMERS?

A. Yes. While credit ratings are important to both debt and equity investors for a variety of reasons, their most important purpose is to communicate to investors the financial strength of a company or the underlying credit quality of a particular debt security issued by that company. It is a well-established fact that a utility's credit ratings have a significant impact as to whether that utility will be able to raise capital on a timely basis and upon reasonable terms. As respected economist Charles F. Phillips stated in his treatise on utility regulation:

> Bond ratings are important for at least four reasons: (1) they are used by investors in determining the quality of debt investment; (2) they are used in determining the breadth of the market, since some large institutional investors are prohibited from investing in the lower grades; (3) **they determine, in part, the cost of new debt, since both the interest**

> **charges on new debt and the degree of difficulty in marketing new issues tend to rise as the rating decreases**; and (4) they have an indirect bearing on the status of a utility's stock and on its acceptance in the market.[2] [Emphasis supplied.]

Thus, a utility with strong credit ratings is not only able to access the capital markets on a timely basis at reasonable rates, it also is able to share the benefit of those attractive interest rate levels with customers since the cost of capital gets factored into utility rates. Conversely, the lower a regulated utility's credit rating, the more that utility will have to pay to raise funds from debt and equity investors to carry out its capital-intensive operations. In turn, the ratemaking process factors the cost of capital for both debt and equity into the rates that consumers are required to pay. This is especially true for a company like Georgia Power, which needs to attract significant levels of capital in the near term for continued transmission and distribution investment, environmental controls, and the construction of new generation, including new nuclear construction, all the while ensuring continuing reliability and safety of service to its customers.

Q. PLEASE EXPLAIN YOUR THOUGHTS ON THE IMPORTANCE OF REGULATION WITHIN THE CREDIT RATING PROCESS.

A. Regulation is a key factor in assessing the credit profile of a utility because a state public utility commission determines rate levels (recoverable expenses including depreciation and operations and maintenance, fuel cost recovery, and return on investment) and the terms and conditions of service. Regulation thus affects utility investors' decisions because, before major investors will be willing to put forward substantial sums of money, they will want to gain comfort that regulators understand the economic requirements and the financial and operational risks of a

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[2] Phillips, Charles F., Jr., <u>The Regulation of Public Utilities</u>, Arlington, Virginia: Public Utilities Reports, Inc., 1993, at p. 250. See also Public Utilities Reports Guide: "Finance," Public Utilities Reports, Inc., 2004 at pp. 6-7 ("Generally, the higher the rating of the bond, the better the access to capital markets and the lower the interest to be paid.").

changing industry and that their decision-making will be fair and will have a significant degree of predictability.

For these reasons, rating agencies look for the consistent application of sound economic regulatory principles by utility regulators. If a regulatory body were to encourage a company to make investments based upon an expectation of the opportunity to earn a reasonable return, and then did not apply regulatory principles in a manner consistent with such expectations, investor interest in providing funds to such utility would decline, debt ratings would likely suffer, and the utility's cost of capital would increase.

Q. WITHIN THIS INCREASINGLY STRESSED ENVIRONMENT, HOW IS THE COMMISSION VIEWED BY THE FINANCIAL COMMUNITY?

A. Regulatory Research Associates ("RRA"), a respected commentator on U.S. regulatory policy, ranks the Commission among the top third of utility commissions across the country. The beneficial aspect of such ranking for both Georgia Power investors and customers is that it enters into the credit rating process as a positive factor, and provides the agencies with a degree of confidence that the final decision in this rate case will be supportive of the Company's financial situation:

- "[S&P] expects [Georgia Power] to reach a constructive resolution of its pending rate case."[3]
- "The stable outlook reflects Moody's expectation that the company's currently pending rate case will result in a reasonably supportive outcome."[4]

[3] S&P Research: "Georgia Power Co., October 14, 2010.
[4] Moody's Credit Opinion: "Georgia Power Company," August 13, 2010.

Q. CAN YOU DESCRIBE THE EFFECT THAT GEORGIA POWER'S CAPITAL EXPENDITURE PROGRAM HAS ON ITS CREDIT RATING?

A. Yes. Georgia Power plans to expend significant amounts of capital with regard to environmental activities, new generation, including new nuclear, and other operational needs. Rating agencies analyze such capital programs and factor the potential financial effects into their determinations of the appropriate credit ratings for the Company. While acknowledging that the Commission's decisions are "generally constructive and supportive of credit quality," S&P notes that:

> Although the regulatory environment has historically been generally constructive, the large capital spending program … will necessitate timely ongoing rate relief in order to preserve the current financial risk profile and which relief may pressure the company's competitive rates and regulatory relationships, especially given the slowdown in the local economy.[5]

Moody's has offered similar views about the stresses Georgia Power is already facing with regard to its large capital investment program. In discussing its decision to downgrade the Company to 'A3' from 'A2' earlier this year, Moody's cited "cash flow metrics that are weak for the A rating category" owing to the Company's "high capital spending levels and rapidly increasing investment in new nuclear generation."[6]

Q. IN LIGHT OF THESE CIRCUMSTANCES, DO YOU BELIEVE THAT CREDIT RATING AGENCIES WILL REACT POSITIVELY TO THE ROE INCLUDED IN THE SETTLEMENT AGREEMENT?

A. Yes, I believe that a stipulated ROE of 11.15 percent with an earnings range of 10.25 to 12.25 percent will be viewed favorably by the rating agencies and they will consider it to be evidence of continuation of a constructive regulatory environment.

[5] S&P Research: "Georgia Power Co., October 14, 2010.
[6] Moody's Rating Action: "Moody's Downgrades Southern Company and Three Utilities," August 12, 2010.

Q. DO YOU BELIEVE THAT EQUITY INVESTORS WILL ALSO REACT POSITIVELY TO THE STIPULATED ROE?

A. Yes.

Q. WILL A POSITIVE REACTION BY INVESTORS BENEFIT CUSTOMERS?

A. Yes. When investors are willing to deploy their capital to investments such as those Georgia Power will be making, it lowers the overall cost, in terms of debt and equity, which is ultimately paid by customers. That is in part why Georgia Power has been able to maintain its retail customer rates below the national average.

<u>Base Rate Revenue Requirement</u>

Q. HOW WAS THE BASE RATE REVENUE REQUIREMENT CALCULATED?

A. Rebuttal Exhibit 3 shows the components of the total base revenue requirement increase of $562.333 million, effective January 1, 2011, as reduced from the Company's original test year revenue requirement increase of $808.577 million. Our Rebuttal Exhibit 3 is based on PIA Staff witness Henkes' Table 1 on page 10 of his prefiled direct testimony for ease of reference.

Q. WHAT ARE THE SIGNIFICANT DIFFERENCES BETWEEN THE COMPANY'S REQUESTED INCREASE IN REVENUE REQUIREMENTS AND THE INCREASE INCLUDED IN THE SETTLEMENT AGREEMENT?

A. As reflected in Rebuttal Exhibit 3, the primary differences between the Company's revenue requirement increase of $808.577 million and the Settlement Agreement increase of $562.333 million are as follows:

- Test period environmental revenue requirements of approximately $167.815 million have been included in the ECCR tariff. Additionally, acceptance by the Company of PIA Staff's adjustment to levelize the

ECCR tariff revenue requirements over the term of the ARP added $14.783 million.

- Test period revenue requirements of approximately $31.614 million have been included in the DSM tariffs.

- Filing corrections acknowledged by the Company reduced revenue requirements by $31.984 million.

- Extending the depreciable lives of the Plant McIntosh combined cycle generating units, and certain transmission and distribution assets, as well as an adjustment to the dismantlement costs of generating unit common facilities reduced the Company's requested depreciation expense by approximately $67.015 million.

- Additional acceptance by the Company of PIA Staff's adjustments related to Environmental Remediation Accrual; Storm Damage Accrual; Materials and Supplies ("M&S") Inventory; Proceeds from Scrap Sales; Property Tax True-ups; and Uncertain Tax Positions reduced the Company's requested revenue requirements by a total of $20.059 million.

- Agreement for settlement and compromise purposes only to a quantification, but not to the rationale, of adjustments proposed by various PIA Staff Witnesses related to the 2010 ECCR Deferral; Industrial Sales; RTP Sales; Wholesale Capacity Sales; Affiliate Transactions and other Miscellaneous Income reduced the Company's requested revenue requirements by $42.1 million.

- The Stipulating Parties acceptance of an 11.15 percent ROE reduced the Company's requested revenue requirements by approximately $94.686 million.

- Test period revenue requirements of $20.911 million have been included in the MFF tariffs. Such MFF amounts were further reduced by $5.182 million consistent with the other adjustments described above.

<u>Tariff Changes and Accruals During Operation of Plan</u>

Q. WHY IS IT APPROPRIATE FOR THE COMMISSION TO ALLOW THE CONTINUATION OF THE ECCR TARIFF?

A. The ECCR tariff was designed and approved by the Commission in 2007 to collect costs required to comply with environmental mandates. Such mandates require the Company to construct, install, operate and maintain new environmental control facilities. The ECCR tariff collects the investments, depreciation and operation and maintenance ("O&M") expenses related to such compliance.

In the Company's 2007 rate case stipulating parties agreed upon the concepts and design of the ECCR tariff, and there was considerable evidence presented upon the types of expenses that were being incurred for environmental compliance. No one during this proceeding has alleged that the ECCR tariff has been deficient in accomplishing the objectives for which it was adopted.

Accordingly, the ECCR tariff continued in this case includes the projected costs to construct, install, operate and maintain new environmental control facilities over the next three years (2010 through 2013). PIA Staff witness Mr. Henkes proposed levelizing the costs for the three-year period, resulting in an annual revenue requirement of $167.815 million as reflected on Rebuttal Exhibit 3.

Q. WHY IS IT APPROPRIATE FOR THE COMMISSION TO ALLOW THE COMPANY TO DEFER POTENTIAL CHANGES IN ENVIRONMENTAL COSTS?

A. It is quite possible, if not probable, that the Company will face new or modified environmental regulations or legislation during the term of the ARP. The Company provides the impacts of such changes to the Commission to review in the form of a requested update to our IRP. Under the terms of the Company's proposed ECCR tariff, any cost changes related to Commission-approved IRP updates would have been recovered through the annual ECCR tariff revision process. Paragraph 7 of the Settlement Agreement addresses this potential issue by requiring the Company to defer any related costs associated with such Commission-approved changes as a regulatory asset. In this manner, the Company maintains the ability to recover these costs, and customers benefit from additional rate stability.

Q. WHY IS IT APPROPRIATE FOR THE COMMISSION TO ALLOW UPDATES TO THE COSTS AND APPORTIONMENT OF FRANCHISE FEE COSTS TO BE RECOVERED BY THE MFF TARIFF?

A. The MFF tariff collects the franchise fees that the Company must pay to cities in which it does business. These are legitimate costs of doing business, and the rate recovery for such costs underwent intense Commission scrutiny in Docket Nos. 21112 and 25060. The addition or deletion of cities within the Company's service territory can change the revenues required from customers that receive service inside the municipal limits of the cities the Company serves versus the Company's other customers that receive service outside municipal limits, as described in more detail in the Direct Testimony of Ms. Daiss and Mr. Morris. (Tr. 175-76) Accordingly, the updates allowed by the Settlement Agreement will reflect those changes in relative gross receipts between customers served inside and outside municipal boundaries, in addition to changes in the Company's revenues as allowed under the ARP or through full cost recovery proceedings consistent with the Commission's Orders. No party to this case has objected to this treatment as proposed by the Company.

Q. WHY IS IT APPROPRIATE FOR THE COMMISSION TO ALLOW UPDATES TO THE COSTS AND APPORTIONMENT OF SUCH COSTS TO BE RECOVERED BY THE DSM TARIFF?

A. In the Company's recent DSM certification proceeding in Docket 31082, the Commission certified seven new DSM programs. Under the terms of the stipulation adopted by Commission, spending under the certified programs will "ramp up" from 2011 to 2013. Thus, the amount of costs to be recovered will necessarily vary from year to year. Formulation of a tariff for the recovery of such certified costs was properly left for the Company's next rate case, including the issue of the appropriate allocation of the additional sum. In light of the Commission's order certifying the DSM programs, it is appropriate for the Commission to allow updates to the costs and apportionment of such costs to be recovered by the DSM tariff. No party in this case has objected to this treatment as proposed by the Company.

Q. HOW WILL THE ADDITIONAL SUMS ASSOCIATED WITH THE COMMERCIAL AND RESIDENTIAL DSM PROGRAMS BE COLLECTED?

A. According to Paragraph 17 of the Settlement Agreement, the DSM-R and DSM-C tariffs proposed by the Company in this case will recover both the program costs and the additional sum (in 2012 and 2013) associated with each residential or commercial program. Although the benefits of the certified DSM programs go to all customers, the greatest benefit goes to the customer class that can take advantage of the programs by actually participating in them. Therefore, the residential and commercial classes are appropriately responsible for all costs associated with their own programs. Amounts collected by these tariffs will be trued up as agreed to in the Commission's Orders in Docket Nos. 31081 and

31082.

Rate Design

Q. DOES THE SETTLEMENT AGREEMENT ADDRESS THE ET TARIFF?

A. Yes. Paragraph 10 of the Settlement Agreement states that the ET tariff will only be increased by one third of what it would otherwise be increased under the "equal allocation" method. Georgia Power serves the Metropolitan Atlanta Rapid Transit Authority ("MARTA") under the RTP-HA tariff with the customer base line ("CBL") priced on the ET tariff. As Mr. David M. Springstead described on page 4 of his prefiled testimony, MARTA provides bus and rail service to nearly one-half million passenger boardings in its service area, as well as connecting bus service for its regional partners, Cobb Community Transit, Gwinnett County Transit and the Georgia Regional Transportation Authority. Additionally, the Cost of Service analysis filed by Georgia Power as result of a hearing request finds that MARTA under the RTP-HA tariff and the ET tariff for the incremental and CBL portion of its load, respectively, are currently above parity (Hearing Request-1-5). The Stipulating Parties recognize MARTA's benefit to the metro-Atlanta region, its budget restraints and the cost of service evaluation and therefore agree that the ET tariff should receive a smaller increase than the original increase proposed by the Company.

Q. DOES THE SETTLEMENT AGREEMENT ADDRESS THE ILR TARIFF?

A. Yes. Paragraph 11 of the Settlement Agreement provides that the ILR tariff shall continue to insure that customers eligible for the ILR-2 tariff will continue to receive only 90 percent of what those customers would otherwise have been increased under the modified allocation methodology proposed by Mr. Watkins in this case. The extension of the ILR tariff will provide economic benefit and rate continuity for Georgia Power's existing customers.

Q. DOES THE SETTLEMENT AGREEMENT ADDRESS ECONOMIC DEVELOPMENT ISSUES?

A. Yes, paragraph 13 of the Settlement Agreement provides that the Stipulating Parties will work together to discuss options for a new Economic Development Incentive Program ("EDIP") that will not negatively affect non-industrial customers. As Dr. Roger Tutterow testified in his prefiled testimony on behalf of the Georgia Industrial Group ("GIG") and the Georgia Traditional Manufacturers' Association ("GTMA"), increases in energy rates raise the cost to business of producing goods and services. According to Dr. Tutterow, the current economic climate in Georgia during the most recent recession caused employment and output to decrease by as much as any recession since the "great depression", and that economic recovery will take "several more years" before employment returns to pre-recession levels. (Tr. 1492-93) Given the current poor economic climate, the Stipulating Parties see a need to discuss the creation of an EDIP that will help industries face regional, national and international competition. This benefits all customers because as those industries leave, not only do they take their tax base and jobs with them, they leave behind fixed costs on the Georgia Power system which must be paid for by other customers.

Q. HOW DOES THE SETTLEMENT AGREEMENT RESPOND TO SOME INTERVENORS' REQUESTS FOR EXPANDED RTP TARIFF ELIGIBILITY?

A. Paragraph 14 of the Settlement Agreement addresses an RTP tariff expansion. As result of the Company's 2004 rate case, 90 MW of existing large commercial load was allowed to be priced under the incremental portion of the RTP tariffs. Approximately 25 MW of the original offering were not subscribed. The Settlement Agreement allows customers who were enrolled in the original offer from the 2004 rate case to move their existing load to incremental RTP up to the remaining amount on a first come, first served basis, and limited to a 60 percent CBL per customer, effective January 1, 2012. As Mr. James T. Selecky testified on behalf of the Commercial Group, some commercial customers with older facilities have urged the Commission to allow them to have more RTP options to compete with newer commercial customers. (Tr. 1462-63) The Commercial Group is comprised of both older and newer commercial customers. The Stipulating Parties agree to allow large commercial customers to migrate load to incremental RTP on this limited basis.

Q. HOW DOES THE SETTLEMENT AGREEMENT ADDRESS RATE PARITY ISSUES?

A. The rate increases resulting from this Settlement Agreement will be allocated by rate group using the revenue distribution method recommended by Mr. Watkins in exhibit GAW-11, with a few exceptions. Mr. Watkins' spread in GAW-11 will be adjusted for balancing and will reflect the Company's original recommendation concerning the rate increase application to the marginal group. Additionally, the TOU-SC and FPA tariffs of the marginal group will receive the base adjustment with no parity adjustment. Due to the fundamental design of the RTP tariffs, the CBL portions of the Company's customers on RTP tariffs will reflect the rate increases as proposed by Mr. Watkins for their respective groups. Finally, revenue erosion due to the Settlement Agreement from the adjustments to the ET tariff, the extension of the ILR tariff and the RTP tariff expansion, in Paragraphs 10, 11 and 14 respectively, will be spread equally to all base tariffs within the affected rate group.

As Mr. Watkins said on page 29 of his pre-filed testimony, "…if CCOSS [Class Cost of Service Study] results consistently show over or under earnings across time and across CCOSS, some consideration should be given to CCOSS results." Therefore, Mr. Watkins recommended some movement towards narrowing the gap between the class rates of return to address parity. The Stipulating Parties see value in Mr. Watkins' recommendation and desire to implement it the way it is described in Paragraph 15 of the agreement.

Q. WILL RESIDENTIAL TIME OF USE ("TOU") CUSTOMERS BE ABLE TO MOVE FROM THE TARIFF AFTER THEIR INITIAL TWELVE MONTH COMMITMENT?

A. Yes, as addressed in Paragraph 16 of the Settlement Agreement, residential TOU tariff customers will be allowed to opt-out of the tariff at any time after they complete their original twelve month commitment to the tariff, as recommended by Mr. Watkins in his prefiled testimony. (Tr. 1213-14) The Company will also work with the PIA Staff to develop a proper notice process for informing residential TOU tariff customers of their rights and responsibilities under the tariff.

Q. HOW DOES THE SETTLEMENT AGREEMENT ADDRESS SOME INTERVENORS' REQUEST TO OPT-OUT OF THE DSM-C TARIFF?

A. This issue may be addressed by interested parties in the 2013 IRP, per paragraph 18 of the Settlement Agreement. The commercial DSM programs are prescribed by the Commission's Orders in the 2010 IRP and DSM Certification Proceedings (Docket Nos 31801 and 31802), including the related settlement agreement in that case (the "2010 IRP and DSM Certification Settlement") approved by the Commission. The 2010 IRP and DSM Certification Settlement states that "program costs will be recovered in a rider collected from the class to which the program is directed" and mentions nothing about an "opt-out" program. The potential for a customer "opt-out" was considered during the IRP proceedings; however, the Commission chose to not include any such provision in the DSM programs. If an opt-out program is to be considered in the future, the 2013 IRP proceeding is the proper forum.

Q. WHAT PROPOSED CHANGES TO THE TOU-MB TARIFF DOES PARAGRAPH 19 OF THE SETTLEMENT AGREEMENT MAKE?

A. The Settlement Agreement calls for a revenue-neutral redesigned TOU-MB rate that will feature a super off-peak time period. To limit the revenue erosion due to the redesign, this tariff will only be available for fast-food restaurants after January 1, 2011. Additionally, TOU-MB will be adjusted toward parity in the manner described in Paragraph 15 of the Settlement Agreement. As described by Mr. Russell L. Klepper of AFFIRM, a super off-peak time period will provide an incentive that does not exist under the current TOU-MB tariff for customers to shift their load to the super off-peak period. As Mr. Klepper states in his prefiled testimony, the shift may "result in increased economic efficiency because any such load increase will not require any incremental additional of generating, transmission or distribution, and thus will increase utilization of Georgia Power's electric system." (Tr. 1289) With this in mind, the Stipulating Parties see value in providing a super off-peak time for TOU-MB customers.

Intervenors' Issues Not Addressed by the Settlement Agreement

Q. SHOULD THE INCLUSION OF THE PREPAID PENSION ASSET BE REMOVED FROM RATE BASE AS PROPOSED BY MR. PRISCO?

A. No. The Commission has allowed the prepaid pension asset in rate base since the Company's 1991 rate case (Docket No. 4007). The Commission confirmed this decision in the 1998 rate case (Docket No. 9355) as well as the 1995 earnings review (Docket No. 6292). In the 2001 rate case, the Commission specifically ordered that the Company keep its prepaid pension in rate base. The Company has continued to include the prepaid pension asset in rate base in the 2004 (Docket No. 18300) and 2007 (Docket No. 25060) rate cases in accordance with those orders.

Q. WHY IS THIS THE APPROPRIATE TREATMENT OF THE PREPAID PENSION ASSET?

A. The prepaid pension asset is the result of strong trust fund earnings that have produced pension income. This pension income has provided significant cumulative benefits to ratepayers through reductions in the cost of service. Its inclusion in rate base from 1991 to 2010 has reduced the Company's cost of service to customers by approximately $258 million as shown in the Company's response to STF-HC-1-23. As the Company cannot withdraw the funds from the pension trust, including the prepayment in rate base is an appropriate means of allowing the Company to recover carrying costs on this amount.

Q. IN RELATION TO THE PATIENT PROTECTION AND AFFORDABLE CARE ACT AND THE HEALTH CARE AND EDUCATION AFFORDABILITY RECONCILIATION ACT OF 2010, IS THE COMPANY INAPPROPRIATELY CHARGING CURRENT RATEPAYERS FOR A FUTURE TAX CONSEQUENCE AS ALLEGED BY KROGER WITNESS KEVIN C. HIGGINS?

A. No. The Company requested recovery of $50 million recorded as a healthcare legislation regulatory asset to be amortized over 12 years beginning January 1, 2011. This regulatory asset was recorded in March 2010 when the Patient Protection and Affordable Care Act ("PPACA") lowered the future tax benefits associated with post retirement medical deductions. Prior to the passage of the PPACA, the Company could deduct 100 percent of the amount paid out. However, the new legislation requires the tax deduction to be reduced by the amount of Medicare drug subsidy received. This decreases the amount of tax deductions the Company will be able to take on its tax return. Subsequently, these larger future tax costs reduce the associated deferred tax asset that existed before PPACA was adopted. Therefore, FASB Statement No. 109, now ASC 740, required the Company to reduce its deferred tax asset now. In accordance with FASB Statement No. 71, now ASC 980, the Company recorded a regulatory asset. The Company requested a 12-year amortization period to match the related retirement benefit costs. This treatment is consistent with the remaining amortization period for a similar regulatory asset recorded in 2008 related to a required change in accounting for pensions and other post-retirement benefits, as approved by the Commission in the Company's 2007 rate case, Docket No. 25060.

Q. DOES THE COMPANY AGREE WITH KROGER WITNESS MR. HIGGINS' PROPOSED CHANGES IN THE TREATMENT OF MARGINS FROM ECONOMY ENERGY/OPPORTUNITY SALES AND MARKET-BASED TARIFF SALES?

A. No. Mr. Higgins proposed that the Commission require Georgia Power to credit customers with: (a) 100 percent of projected test year profits from economy energy/opportunity sales; (b) 100 percent of projected test year capacity revenues from market-based tariff sales; and (c) 100 percent of projected test year profits from market-based tariff energy sales. (Tr. 770) The Company currently shares 75 percent of the profits related to economy energy sales and 80 percent of the profits from opportunity sales as ordered by the Commission. This arrangement benefits both the Company and customers. By allowing the Company to keep a part of the profits, both customers and the Company benefit from the pursuit of these types of sales.

Q. SHOULD THE COMMISSION CONSIDER THE RECOMMENDATION OF GEORGIA WATCH CONSULTANT GEORGE W. EVANS REGARDING THE POSSIBLE RETIREMENT OF CERTAIN OF THE COMPANY'S GENERATING UNITS?

A. No. A rate case is an inappropriate forum to consider such issues. The proper forum for the consideration of potential unit retirements is in the IRP. In an IRP proceeding the Commission reviews the Company's analysis of the economics of all generating units and their potential expansion or retirement.

Q. HAS THIS COMMISSION RECENTLY CONCLUDED AN IRP PROCEEDING?

A. Yes, the Commission held its 2010 IRP proceeding in the first half of this year and issued the related Order on July 13, 2010.

Q. DID MR. EVANS PROVIDE ANY INFORMATION TO THE COMMISSION REGARDING THE IMPACT ON REVENUE REQUIREMENTS OF HIS RECOMMENDED RETIREMENTS?

A. Mr. Evans did not provide such analysis in his pre-filed direct testimony. However, under cross examination, Mr. Evans claimed that such retirements would result in a $22 million reduction to the revenue requirement. (Tr. 1614)

Q. DO YOU AGREE WITH MR. EVANS' RECOMMENDATION THAT CUSTOMERS WOULD BENEFIT FROM THE IMMEDIATE RETIREMENT OF CERTAIN COAL UNITS?

A. No. There is no current or future requirement to install on these units the environmental controls described by Mr. Evans. The U.S. Environmental Protection Agency ("EPA") is not expected to issue final rules regarding standards for control of hazardous air pollutants until November 2011. These final rules will determine whether installation for these units is required. That is why the Company conducted two separate retirement analyses in its 2010 IRP--one assuming that installation of environmental controls is required and another assuming that installation of environmental controls is not required. The EPA is also in the process of developing a rulemaking proposal regarding potential additional regulation of coal combustion by-products. The Company has thoughtfully developed a plan and timeline for any potential needed decertification requests and for filing any resulting capacity need. This plan and timeline is structured to ensure that no final decisions are made regarding retirement or replacement capacity until the EPA's final rules are known. The Commission has reviewed and approved both the IRP retirement studies, as well as the Request for Proposals action plan and timeline, which is currently ongoing in Docket No. 27488.

Q. IF IT WERE CERTAIN TODAY THAT ADDITIONAL ENVIRONMENTAL CONTROLS WOULD BE REQUIRED ON THE COAL UNITS WHICH MR. EVANS RECOMMENDED FOR IMMEDIATE RETIREMENT, DO YOU AGREE WITH MR. EVANS' CONCLUSION REGARDING THE BENEFIT OF IMMEDIATELY RETIRING THESE UNITS?

A. No, Mr. Evans did not have the necessary level of cost detail to conduct a reliable analysis. Mr. Evans' only basis for his non-fuel cost assumptions is the Company's response to data request STF-GDS-3-16. This data provides 2010 budget and test year data related to the Company's fossil plants' O&M expenses. This data is not sufficient in detail to ascertain the relevant cost components that could be avoided by retiring the units. This data also does not provide a sufficient level of detail to determine the impact of retirement on revenue requirements. Therefore, his analysis and conclusion cannot be relied upon. Mr. Evans has failed to consider allocations of common costs that could not be avoided by retirement of certain units, the current remaining net book value of the units, the dismantlement and removal costs and employee impacts.

Q. DOES THE COMPANY AGREE WITH GIG/GTMA CONSULTANT POLLOCK'S RECOMMENDATION TO USE THE COMPANY'S THEORETICAL DEPRECIATION RESERVE SURPLUS TO PARTIALLY OFFSET THE COMPANY'S REQUESTED INCREASE IN REVENUE REQUIREMENTS?

A. No. Mr. Pollock's recommendation that over $200 million of the Company's theoretical depreciation reserve surplus be used to offset the requested increase in 2011 revenue requirements is not supportable under either current U.S. Generally

Accepted Accounting Principles ("GAAP"), or the Code of Federal Regulations ("CFR") 18, Part 101 Uniform System of Accounts.

Q. PLEASE DESCRIBE THE RELEVANT GAAP REQUIREMENTS FOR DEPRECIATION.

A. ASC Topic 360 Property, Plant, and Equipment ("PP&E") provides guidance on the subject of depreciation of PP&E; primarily in ASC 360-10-35-2 through 35-11.

That guidance provides that the remaining lives of assets should be periodically reviewed and revised to recognize changes in conditions, where the cost of a productive asset is a cost to be recognized over the expected useful life of that asset. Specifically ASC 360-10-35-3 and 4 states:

> "Depreciation expense in financial statements for an asset shall be determined based on the ***asset's useful life***. The cost of a productive facility is one of the costs of the services it renders during its useful economic life. GAAP requires that ***this cost be spread over the expected useful life of the facility in such a way as to allocate it as equitably as possible to the periods during which services are obtained from the use of the facility***. This procedure is known as depreciation accounting, a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. ***It is a process of allocation, not of valuation***."
>
> (Emphasis added)

Q. PLEASE DESCRIBE THE RELEVANT REQUIREMENTS FOR DEPRECIATION FOR FERC PURPOSES.

A. CFR General Instructions, Part 22, which states:

> "Depreciation Accounting.

A. *Method*. Utilities must use a method of depreciation that ***allocates in a systematic and rational manner the service value of depreciable property over the service life*** of the property.

B. ***Service lives. Estimated useful service lives of depreciable property must be supported by engineering, economic, or other depreciation studies***.

C. *Rate*. Utilities must use percentage rates of depreciation that are based on a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property to the service life of the property. Where composite depreciation rates are used, they should be based on the weighted average estimated useful service lives of the depreciable property comprising the composite group."

(Emphasis added)

Q. HOW DOES THE COMPANY'S DEPRECIATION METHOD COMPLY WITH THESE REQUIREMENTS?

A. The Company uses a depreciation method that is best described as a composite straight-line method for each functional classification of electric plant (per FERC Account 108 "Accumulated Provision for Depreciation" Part C). This method is based on the un-depreciated cost plus cost of removal, less salvage value, over the estimated remaining useful life.

Therefore, when the Company places PP&E assets into service, the service lives are determined in accordance with GAAP and the CFR and, specifically, the depreciation is spread over the expected useful life of the asset in such a way as to allocate it as equitably as possible to the periods during which services are obtained from the use of the facility.

While changes in facts and circumstances affect the ongoing depreciation cost, such changes in depreciation rates are deemed equitable to the periods in which the known facts and circumstances are applicable i.e. the straight line method which is common and prevalent in the industry.

Q. PLEASE DESCRIBE A THEORETICAL DEPRECIATION RESERVE.

A. A theoretical depreciation reserve is the result of calculating the theoretical value for accumulated depreciation assuming the current expected useful life had been used since the asset was placed in service. A prime example would be nuclear generating units. Originally, nuclear plants were assumed to have a service life of no more than 40 years since their operating licenses were for 40 years. As the Nuclear Regulatory Commission ("NRC") began to review and approve applications for 20 year extensions of operating licenses, the service lives of the plants were extended to 60 years. If the extension application was approved after 20 years of successful operation, the theoretical depreciation reserve would be calculated assuming 60 years had been used as the expected useful life since the unit went into service. Because the plant was originally depreciated at a rate assuming a 40 year life, then a new, lower depreciation rate would be used when the service life was revised to 60 years.

Q. WHY DOES THE COMPANY HAVE A THEORETICAL RESERVE SURPLUS?

A. The Company's theoretical reserve surplus of approximately $556 million, as reflected in the Company's depreciation study filed in this case, is primarily the result of Commission orders to accelerate nuclear depreciation. In the mid 1990s, the Company and the Commission were concerned about the potential cost of stranded assets as the result of electric utility industry restructuring and deregulation. In order to be prepared and minimize rate impact on customers, the Commission made a policy decision to accelerate the depreciation of Plant Vogtle Units 1 and 2 in Docket No. 6292. As a result of this order, the Company recorded approximately $467 million of accelerated depreciation. In addition, as described in the previous example, the NRC has extended the operating licenses of both Plants Hatch and Vogtle from 40 years to 60 years.

Q. HOW WOULD THIS OFFSET BE ACCOMPLISHED?

A. Mr. Pollock does not provide a specific methodology for accomplishing his recommendation. However, his testimony implies a method that would effectively reverse previously recorded depreciation expense and reduce the accumulated depreciation balance. Mr. Pollock references recent decisions by the Florida Public Service Commission as supporting his proposal.

Q. DO ACCOUNTING RULES LIMIT THE COMPANY'S ABILITY TO CHANGE DEPRECIATION EXPENSE AND ACCUMULATED DEPRECIATION RESERVE BALANCES?

A. Yes. First, it is important to distinguish between depreciation expense and depreciation reserves. Depreciation expense relates to expenses to be recorded in the future; while the reserve relates to the sum of such expenses recorded in prior periods.

In accordance with FASB Statement No. 71 (now ASC 980-10), a regulator may order changes in depreciation expense such that one functional class of property's depreciation expense is lowered (e.g., nuclear), while another class of property's expense is increased (e.g., fossil); with the Generally Accepted Accounting Principles ("GAAP") limitation that such changes ordered by the regulator can not result in negative depreciation for any class of property. As discussed previously, the FERC requires depreciation expense to be based on a systematic and rational method.

However, transfers of actual depreciation reserve balances between functional classes of property are not permitted under accounting rules, either for financial reporting purposes, or by the FERC, which issued an order in 1996 that specifically rejected the transfer of depreciation reserve balances from transmission and distribution plant to nuclear production plant.

Q. WHAT IS THE PURPOSE OF THESE LIMITATIONS?

A. The effect of reducing depreciation expense so much that it becomes negative, or transferring actual depreciation reserve balances, is to change the actual asset net book values. For example, a reserve transfer would increase, or "write-up" the net book value of the functional asset class for which the accumulated reserve balance was reduced. Likewise, the net book value of the functional asset class for which the accumulated reserve balance is increased, would be reduced, or "written-down."

GAAP does not allow for "write-ups" of property except when a reorganization or purchase-method acquisition occurs. Likewise, "write-downs" are only permitted when an impairment occurs. As mentioned previously, the FERC has also rejected such results as being improper under its Uniform System of Accounts, which this Commission has adopted.

Q. HOW DO THESE LIMITATIONS AFFECT GEORGIA POWER?

A. Like other utilities, Georgia Power must comply with these accounting limitations. As such, any changes to the Company's proposed depreciation expense must consider the annual depreciation expense on a functional basis, which is included in the Company's depreciation study. In compliance with these requirements, the Company's depreciation expense, as proposed, provides the necessary systematic and rational approach to reduce the theoretical reserve excess over the remaining lives of the assets.

Q. MR. POLLOCK ASSERTS THAT A THEORETICAL DEPRECIATION RESERVE SURPLUS CAN BE AMORTIZED IN A MANNER SIMILAR TO COST OF REMOVAL LIABILITIES. DO YOU AGREE?

A. No. Non-ARO cost of removal obligations are regulatory liabilities, which were recorded under the guidance of this Commission following the Company's adoption of FASB Statement No. 143 and FIN 47 (now ASC 410). As such, the Commission has ultimate discretion over the related amortization period, which it addressed in its 2009 order in Docket No. 25060. Depreciation reserves are not regulatory liabilities. Therefore, the Company and the Commission are bound by the accounting treatment required by GAAP and the FERC, as described above.

Q. DID MR. KING ADDRESS MR. POLLOCK'S RECOMMENDATION?

A. Yes. During the hearing, Mr. King recognized that some policy issues have a greater urgency for the Commission than others and that it depends on the circumstances. For example, while Mr. King supported Mr. Pollock's argument of intergenerational equity as a reason for using amortization related to "theoretical depreciation" as a way to lower current rates (Tr. 992-993), he also agreed with Commissioner Baker that the Company is facing the potential early retirement and requisite dismantlement of AROs associated with increasingly restrictive pollution control measures being contemplated by Congress, the U. S. EPA, and the Georgia Department of Natural Resources Environmental Protection Division that could also have similar effects. As a result, Mr. King concluded "the safe course is to keep using remaining life depreciation which would more slowly amortize this reserve excess." (Tr. 993)

Q. IS MR. POLLOCK'S RECOMMENDATION CONSISTENT WITH THIS COMMISSION'S HISTORICAL TREATMENT OF DEPRECIATION EXPENSE?

A. No. In every previous rate case for Georgia Power, the Commission has approved depreciation rates based on the remaining useful lives of the assets. As discussed previously, the one exception to this policy occurred when the Commission specifically ordered accelerated depreciation for Plant Vogtle to address the potential stranded cost in the event of deregulation. As such, Mr. Pollock's recommendation should be rejected in favor of the depreciation adjustments reflected in the Settlement Agreement.

Q. WHILE MANY INTERVENORS HAVE NOT SIGNED ON TO THE SETTLEMENT AGREEMENT TO DATE, ARE THERE PARTS OF THE SETTLEMENT THAT ADDRESS INTERVENOR CONCERNS?

A. Yes, many Intevenor positions are addressed in the Settlement Agreement. MARTA's ET tariff will be increased by only one third of what it would otherwise be increased under the Company's original rate increase allocation. The ILR tariff will be extended for qualifying industrial class customers, and the PIA PIA Staff and Georgia Power will begin discussing options for a new industrial Economic Development Incentive Program. The Settlement Agreement provides an opportunity for certain large commercial customers to move existing load to RTP. Georgia Power's rates will be adjusted to represent closer parity among the rate groups, as requested by GIG, GTMA, AFFIRM and MARTA. This movement toward parity has been a goal of many of these Intevenors for many years. Residential customers will be able to take advantage of a more flexible TOU tariff. Finally, TOU-MB tariff fast food customers will be offered a new super off-peak pricing period, as requested by AFFIRM. This Settlement Agreement represents movement toward Intervenor positions in many areas.

Q. HAVE YOU REVIEWED THE OTHER RECOMMENDATIONS PUT FORWARD BY INTERVENORS IN THIS PROCEEDING?

A. Yes; and we have addressed many of the key recommendations of the intervenors in this case. We note, however, that the fact the Company has not responded to every intervenor recommendation should not be viewed as indicating that the Company supports or agrees with such recommendations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.