

**Georgia Power Company’s 2013 Integrated Resource Plan
and Application for Decertification of Plant Branch Units 3 and 4,
Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates
Units 1-5, Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6**

Main Document

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2013 INTEGRATED RESOURCE PLAN

TECHNICAL APPENDICES INDEX

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2013 IRP PLAN & MIX STUDY
GENERATION TECHNOLOGY DATA BOOK
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TECHNICAL APPENDIX VOLUME 2

BUDGET 2013 LOAD AND ENERGY FORECAST
ENVIRONMENTAL COMPLIANCE STRATEGY
FINANCIAL REVIEW
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DSM PROGRAM DOCUMENTATION
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TRANSMISSION PLAN

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1 – SUMMARY OF 2013 INTEGRATED RESOURCE PLAN

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SECTION 1 - SUMMARY OF 2013 INTEGRATED RESOURCE PLAN

1.1 FOREWORD

This 2013 Integrated Resource Plan (“2013 IRP”) is the eighth IRP filed by Georgia Power Company (“Georgia Power” or the “Company”) since enactment of the Integrated Resource Planning Act in 1991, O.C.G.A. § 46-3A-1 et seq. (“IRP Act”), which requires the filing of such a plan every three years. This 2013 IRP is the product of a thorough planning process that has resulted in a robust and diverse portfolio of generation and demand side resources that will continue to provide customers reliable service at rates below the national average.

The Company filed an updated IRP on August 4, 2011 in Docket No. 34218 (“2011 IRP Update”) in connection with its application for the decertification of Plant Branch Units 1 and 2 and Plant Mitchell Unit 4C and the certification of certain power purchase agreements (“PPAs”) identified through the 2015 Request for Proposals (“RFP”). At that time, the Company faced a significant amount of uncertainty as it sought to plan for the impact of numerous potential environmental regulations, the most significant and immediate of which was the United States Environmental Protection Agency’s (“EPA”) Mercury and Air Toxics Standards (“MATS”) rule, which had not been finalized at the time of the initial filing. The Company and the Georgia Public Service Commission (“Commission”) grappled with a number of difficult decisions in light of the potential impact of the MATS rule. Specifically, the Company requested and received authorization to proceed with initiation of construction of baghouses that were anticipated to be needed at Plants Bowen, Wansley and Hammond to comply with the MATS rule and also recommended deferral of decisions concerning 2,600 megawatts (“MW”) of generating units. However, the Company asserted that it was reasonable to assume that 2,000 MW of that capacity would be unavailable in 2015 as a result of the MATS rule.

Now that the Company has had the opportunity to further analyze and assess the impact of the final MATS rule, a significant portion of the uncertainty that framed the discussion in the 2011 IRP Update has been eliminated, as the Company has developed a compliance plan that will maintain long term reliability for customers in a cost-effective manner. As anticipated in the 2011 IRP Update, the Company will be required to incur significant capital costs to comply with the final MATS rule. However, the projected capital costs required for compliance are less than

had been anticipated at the time of the 2011 IRP Update. These costs are lower for two primary reasons. First, key changes were made to the final rule enabling the Company to lower the cost of compliance, thereby benefitting customers. Southern Company, on behalf of Georgia Power and its other operating companies, as well as this Commission, played a major role in communicating to the EPA the need for changes because of the impacts that the overly stringent proposed rule could have had on the reliability and affordability of electricity. Second, because of these changes in the rule, the Company was able to utilize its and Southern Company's substantial research and development ("R&D") capabilities and technical expertise to develop innovative compliance solutions that were less expensive than previously expected. The Company has explored a wide range of compliance options for its generating units. From plant to plant, and in some cases from unit to unit, a unique set of compliance options are feasible based on factors such as the unit's design, operating characteristics, existing environmental controls, etc.

As has been previously communicated to the Commission, the Company has determined that only Plant Bowen Units 3 and 4 will require baghouses at this time. MATS compliance can be achieved at Plant Bowen Units 1 and 2, Plant Wansley Units 1 and 2 and Plant Hammond Units 1-4 with the installation of activated carbon and hydrated lime injection systems, a significantly less costly technology than baghouses (an activated carbon and hydrated lime injection system will also be required at Plant Bowen Units 3 and 4 in addition to the baghouses). The difference between the projected cost to install seven baghouses and the currently projected MATS compliance costs equates to a savings of several hundred million dollars for customers.

Plant Scherer Units 1-3 will also be retrofitted with additional controls in order to ensure MATS compliance. Although these units will be well controlled due to installation of the required Georgia Multipollutant rule controls, a bromine injection system will be installed in order to most cost effectively comply with the MATS requirements. Pending a successful test burn and subsequent feasibility study in 2013, the Company also plans to fuel switch Plant McIntosh Unit 1 from Central Appalachian coal to Powder River Basin ("PRB") coal to provide additional economic benefits to customers. With the projected coal change, Plant McIntosh Unit 1 will install an activated carbon and dry sorbent injection system to achieve MATS compliance by April 16, 2016.

The Company's multi-faceted approach to MATS compliance also includes switching to natural gas as the primary fuel at Plant Yates Units 6 and 7 and Plant Gaston Units 1-4. The primary fuel for Plant Yates Units 6 and 7 will be switched from coal to natural gas by April 2015 and the primary fuel for Plant Gaston will be switched from coal to natural gas by April 2016.

Unfortunately, the projected costs to comply with the MATS rule, even in its final form, and other pending environmental regulations have placed significant pressure on the economic viability of several of the Company's fossil generating units to the point that retirement is the most cost-effective approach for these units. Therefore, the Company is seeking decertification for Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, and Plant Yates Units 1-5. These units have a long and distinguished history of service to Georgia Power customers and have had a significant positive impact on the communities in which they operate. Only after extensive analysis and evaluation (which is a staple of both the Company's routine planning and the iterative IRP process), and after exploring a wide range of feasible compliance options, did the Company determine that retirement and decertification of these units is in the best interest of customers. And though the MATS rule and other existing and pending environmental regulations are the key drivers, the current forecasts of natural gas prices and the recent economic downturn and resulting loss of load have also had a negative impact on the economics of these units. While these units have provided significant benefit to customers for decades, the economic analysis now shows that retirement is in the best interest of customers.

In the case of Plant Branch Units 3 and 4, major capital investment would be required to achieve MATS and Georgia Multipollutant Rule compliance. To put the magnitude of these costs into perspective, the total combined cost of MATS compliance for all the units the Company plans to control or fuel switch is roughly equal to the cost of bringing Plant Branch Units 3 and 4 alone into MATS compliance. Aside from the negative economic results of the Plant Branch Units 3 and 4 retirement analysis, such significant up front capital investment would put immediate upward pressure on rates with only a modest chance of long-term economic benefit to customers. As further detailed in Section 1.5.2, the Company also requests an amendment to the decertification date for Plant Branch Unit 1 specified in the Commission's final order in Docket No. 34218. This adjustment will provide the most cost effective method to ensure reliable

startup of Plant Branch Units 3 and 4 until their retirement and allow Unit 1 to continue to provide energy benefits to customers until 2015.

In the case of Plant Kraft Units 1-4, the most feasible MATS compliance option—future operation on oil—does not offer any economic benefit to customers in any of the analysis scenarios. Similarly, in the case of Plant Yates Units 1-5, switching to natural gas as the primary fuel because of the MATS requirements would not offer any economic benefit to customers. And although Plant McManus Unit 1 and 2 would not need additional controls to become MATS compliant, the MATS rule does contain requirements which limit an oil-fired plant's capacity factor.

In addition to the decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, and Plant Yates Units 1-5, the Company also seeks decertification for Plant Boulevard Units 2 and 3 and Plant Bowen Unit 6. Similar to Plant Mitchell Unit 4C, which was decertified in 2012 as a result of the need for significant repairs, Plant Boulevard Units 2 and 3, each 14 MW combustion turbines ("CTs"), recently experienced compressor failures that caused substantial damage. While an economic evaluation of the units results in a positive NPV for customers over a 30-year study period, similar to Mitchell 4C, the Company has requested decertification of the units in light of the age of the units, the possibility of additional reliability issues and costs in the future, the extensive nature of the repairs required, and the possibility of more extensive damage found once the units were opened for more detailed inspection.

The Company has also determined that it will be economically beneficial for customers to retire Plant Bowen Unit 6. Plant Bowen Unit 6 is a 32 MW oil-fired combustion turbine that is only permitted to operate during non-summer months due to ozone nonattainment requirements in the area. Furthermore, removal of the unit as quickly as possible will allow more flexibility for the installation of baghouses on Plant Bowen Units 3 and 4 given certain logistical constraints of the site. When the benefits of retiring the unit became apparent, the Company proactively sought sale opportunities for the generator and was able to reach an agreement to sell the unit, pending Commission approval of the decertification, that is in the best interest of customers. The Company requests that the Commission grant this decertification by April 16, 2013 to take advantage of the sale agreement. Expedited Commission approval of the decertification of the

unit will allow the buyer sufficient time to remove the unit before June 1, 2013, which would ensure that the unit does not impede construction of the baghouses for Plant Bowen Units 3 and 4.

In summary and as specified in the Company's Application for Decertification ("2013 Decertification Application"), the plants for which the Company seeks decertification are Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6, which brings the Company's decertification requests in this filing to a total of 2,093 MW of generating capacity. The slate of generating unit retirements recommended in this case is unprecedented in the history of Georgia Power but, unfortunately, is necessitated by the stringent and costly requirements of the MATS rule and other environmental rules, as well as other economic considerations. It is important to note that Georgia Power is not alone in facing the need to retire substantial amounts of coal- and oil-fired generation. Numerous utilities across the country and their respective state regulatory commissions have made or are facing similar difficult decisions with respect to the future of coal- and oil-fired generating units.

The Company assesses the feasibility of repurposing sites where units have been retired and decommissioned. Future uses of these sites may include development of new generation resources similar to the new combined cycle ("CC") units at Plant McDonough-Atkinson. If the site is not suitable for future generation development or for other utility use, the Company may choose to sell the site. In some cases, sales may allow for other land uses facilitating economic development similar to Plant Riverside in Savannah. In any event, the Company will evaluate the best future use of the property taking into account stakeholder interests and value to customers. The Company's long term planning process also includes identifying, assessing, and acquiring (if needed) sites that are suitable for future generation development. Relevant factors for such assessments may include proximity to electric transmission networks, natural gas pipelines, sources of cooling water, railroads, size of the property and availability of contiguous parcels.

The Integrated Resource Plan presented in this filing maintains an efficient and diverse fleet of supply-side resources coupled with demand side resources. The Company is in the midst of a

significant transition in its fleet that will result in a more diverse fuel portfolio and ensure that Georgia Power is able to continue to provide its customers with reliable and affordable electricity while helping to mitigate the risk of fuel price volatility. This period of transition will also result in a younger, more efficient fleet and one with fewer coal resources, which may lessen customers' exposure to the cost of potential carbon regulation or legislation. Additionally, by further controlling the Company's largest and most efficient coal units (units in which the Company has already invested significant capital costs for environmental controls), the Company retains the significant energy benefits of these units while also positioning itself to be able to respond to future increases or volatility in the cost of natural gas. And by moving forward with switching primary fuels at Plant McIntosh Unit 1, Plant Yates Units 6 and 7 and Plant Gaston Units 1-4, the Company is able to retain the operational and economic benefits of these units for customers. Finally, by deferring a final decision regarding the conversion of Plant Mitchell Unit 3, the Company maintains the option of cost-effectively converting an existing unit to a renewable biomass generating unit in its future resource plans.

The planning process mandated under the IRP Act and overseen by the Commission has resulted in a fleet of supply-side resources that will continue to deliver value to customers for generations to come. The comprehensive and detailed nature of this process ensures that benefits to customers are maximized. For example, the three new Plant McDonough-Atkinson CC units that were identified through the IRP process and constructed under the supervision of the Commission's construction monitoring protocols are now providing highly efficient natural gas generation, capitalizing on the current low natural gas prices and reducing customers' fuel costs (as demonstrated by the Company's recent fuel rate decreases). The construction of the new McDonough-Atkinson units also eliminated the need for significant transmission upgrades that otherwise would have been necessary, further highlighting the benefits of the IRP process. Likewise, the IRP process also identified the value of adding the new Plant Vogtle units, which will bring needed base load capacity and even greater fuel diversity and energy benefits to the Company's fleet.

The Company also continues its pursuit, in collaboration with the Commission, of cost-effective renewable resources. With over 1,088 MW of hydro generation, over 62 MW of solar generation (in service or under contract today), and 142 MW of biomass generation, the Company has

demonstrated a firm commitment to identifying all cost-effective renewable resources for the benefit of customers. In total, the Company expects to have more than 1,500 MW of renewable generation available to serve customers by the end of 2016.

The Georgia Power Advanced Solar Initiative (“GPASI”) is the most recent and most noteworthy step the Company has taken to obtain an increasing amount of solar resources as declining technology prices have made such resources less costly. The GPASI builds on the solar resources already obtained by the Company through the Large Scale Solar (“LSS”) program and the Green Energy Program. After all resources are obtained through the GPASI, the Company expects to have 270 MW of solar capacity under contract in Georgia, putting it among the top U.S. utilities operating in states without a renewable portfolio standard. The Company also continues to engage in R&D efforts to gain more insight into the potential for further utilization of solar resources in Georgia.

Additionally, the Company continues to evaluate the economic benefit to customers of the Plant Mitchell Unit 3 biomass conversion. As detailed further in this filing, a decision concerning the conversion of Plant Mitchell Unit 3 is being deferred at this time. The Company is currently conducting a thorough evaluation of the impacts of the final EPA Industrial Boiler Maximum Achievable Control Technology standard (“IB MACT”) that was released in late December. In this 2013 IRP, Plant Mitchell Unit 3 is currently assumed to be unavailable in 2015 and 2016 and then available as a biomass generating unit in 2017.

The Company also continues its disciplined pursuit of cost-effective Demand Side Management (“DSM”) programs through its collaboration with Commission Staff and the Demand Side Management Working Group. The specific certification and amendment requests of the Company have been made concurrently with this filing in the Application for the Certification of its Amended Demand Side Management Plan in Docket No. 36499 (“2013 DSM Application”). Specifically, in its 2013 DSM Application, the Company requests certification of one new commercial program, amendment of three currently certified programs, decertification of one program (though the program activities will be subsumed by an existing program), and approval of updated program budgets for the remaining programs previously certified in Docket No. 31082. The Company’s current DSM portfolio consists of demand response programs, energy

efficiency programs, pricing tariffs, and other activities. The Company projects that by 2016 these programs will reduce peak demand by approximately 2,000 MW.

The 2013 IRP presented in this filing is robust and capable of sustaining long term reliability in a cost-effective manner through a diverse portfolio of resources. The IRP planning process overseen by the Commission has created a versatile fleet that can respond effectively to swings in gas and coal prices, with new nuclear providing low cost energy and greater fuel cost stability than fossil fuels. With the Commission's oversight, the Company has developed a cost-effective and balanced MATS compliance strategy for the benefit of customers and is also well positioned for compliance with future environmental requirements. The plan also maintains and enhances the Company's current DSM programs. In addition, the Company is well-positioned for the return of customer load growth given Georgia's positive long-term economic prospects as a destination state with a business friendly environment. By 2020, the state of Georgia is projected to add one million new residents, and the ability to have in place the necessary energy infrastructure for such growth is a direct result of the collaborative planning process facilitated by the IRP Act and guided by the Commission. This process has allowed the Company and the Commission to maintain a reasoned and disciplined approach to meeting customer demand while effectively responding to a changing regulatory environment in a way that would not have been achievable through other more narrowly focused approaches, all while maintaining rates below the national average.

In summary, the Company seeks approval of:

- 1) Its 2013 Integrated Resource Plan and the associated Action Plan;
- 2) Decertification of Plant Branch Units 3 and 4, Plant Yates Units 1-5, and Plant McManus Units 1 and 2 effective by the MATS compliance date of April 16, 2015, decertification of Plant Kraft Units 1-4 one year past the MATS compliance date (by April 16, 2016), decertification of Plant Boulevard Units 2 and 3 effective as of the date of the final order in this proceeding, and approval of expedited decertification of Plant Bowen Unit 6 by April 16, 2013 as specified in the 2013 Decertification Application;
- 3) A switch to natural gas as the primary fuel for Plant Yates Units 6 and 7 and Plant Gaston Units 1-4;

- 4) An amendment of the decertification date specified in the Commission's final order in Docket No. 34218 for Plant Branch Unit 1 from December 31, 2013 to coincide with the decertification of Plant Branch Units 3 and 4;
- 5) A certificate of public convenience and necessity for one new DSM program, a certificate amendment for three previously certified programs, decertification of one DSM program, and approval of updated program economics for all other previously certified energy efficiency DSM programs as further specified in the 2013 DSM Application in Docket No. 36499;
- 6) Reclassification of the remaining net book values of Plant Branch Units 3 and 4 and Plant Boulevard Units 2 and 3 as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 31958;
- 7) In the event the Commission does not approve the expedited decertification of Plant Bowen Unit 6, reclassification of the remaining net book value of Plant Bowen Unit 6 as of its respective retirement date to a regulatory asset account and the amortization of such regulatory asset account ratably over a period equal to the unit's remaining useful life approved in Docket No. 31958;
- 8) Amortization of approximately \$38 million of Plant Branch Units 3 and 4 and approximately \$14 million of Plant Yates Units 6 and 7 environmental construction work in progress ("CWIP") (which has been reclassified as a regulatory asset in accordance with the Commission's Order in Docket No. 31958) ratably over a three year period beginning January 2014;
- 9) Reclassification of any unusable material and supplies ("M&S") inventory balance remaining at the unit retirement dates to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 31958 for recovery over a period to be determined by the Commission in the Company's next base rate case following the unit retirements;
- 10) The capital costs the Company will incur for a portfolio of certain renewable demonstration projects (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 2; and

- 11) The capital and operations and maintenance (“O&M”) costs (but not yet the recovery) of measures taken to comply with existing government-imposed environmental mandates, as set out in the Selected Supporting Information section of Technical Appendix Volume 2.

1.2 INTRODUCTION

Georgia Power, a subsidiary of Southern Company, is an investor-owned electric utility serving customers in 57,000 of the state’s 59,000 square miles. The Company serves approximately 2.4 million retail customers in all but four of Georgia’s 159 counties.

Southern Company is the parent of Georgia Power, Alabama Power Company (“Alabama Power”), Gulf Power Company (“Gulf Power”), Mississippi Power Company (“Mississippi Power”), and Southern Power Company (“Southern Power”), (collectively, the “Operating Companies”), as well as certain service and special-purpose subsidiaries. The Operating Companies, together also referred to as the Southern Electric System (“System”), coordinate system operations and jointly dispatch their generating units to capture the economies available from power pooling. The System is a member of the Southeastern Electric Reliability Council (“SERC”), a group of electric utilities (and other electric-related utilities) coordinating operations and other measures to maintain a high level of reliability for the electrical system in the southeastern United States. The four traditional retail operating companies, Georgia Power, Alabama Power, Gulf Power, and Mississippi Power, also participate in coordinated generation and transmission planning as appropriate.

Georgia Power’s common stock is held by Southern Company, which had 149,628 shareholders of record at year end 2012.

Georgia Power has 149 company-owned generating units (36 fossil steam, 71 hydroelectric, 4 nuclear, 5 CCs, and 33 CTs, excluding 4 CTs which are not permitted for normal summer operation) that provide approximately 17,400 MW of retail peak season generating capacity. Of the energy from Company-owned units for the first eleven months of 2012, 42 percent is from coal, 18 percent from nuclear, 4 percent from hydroelectric, and 36 percent from natural gas and oil.

1.3 THE 2010 IRP

In January 2010, Georgia Power filed its seventh IRP. The 2010 IRP was designed to meet the energy needs of the Company's customers using a mix of supply-side and demand-side resources. The Commission approved the IRP developed by Georgia Power with modifications as specified in its order dated July 13, 2010 (the "2010 IRP Order").

In response to the Commission's 2010 IRP Order, the Company took the following actions:

- 1) Updated the cost of Expected Unserved Energy ("EUE");
- 2) Continued to pursue a cost-effective conversion of Plant Mitchell Unit 3 to 100 percent biomass (Docket No. 28158) by completing a study of a direct injection technology which may lead to lower capital cost and higher net capacity compared to other biomass conversion options;
- 3) Responded to the Commission's Order requiring certain actions in regard to DSM programs and planning activities;
- 4) Filed the Achievable Energy-Efficiency Potentials Assessment in January 2012 in response to the Commission's order for a new energy efficiency potential study;
- 5) Filed complete Process and Impact Evaluation result reports in December 2012 for the seven energy efficiency programs certified in the 2010 DSM certification proceeding; and
- 6) Complied with the Nine Step DSM planning process for development of the Company's 2013 IRP DSM plan.

1.4 SIGNIFICANT RECENT DEVELOPMENTS

As discussed in Section 1.1, the need to file the Company's 2011 IRP Update and application was driven largely by the significant amount of uncertainty created by numerous new environmental regulations under development by the EPA. The most significant of these regulations, with the most immediate effect, was the EPA's MATS rule. As a result, the Company recommended, and the Commission approved, numerous actions that sought to mitigate the impact of these environmental rules and minimize costs for customers. These included:

- Initial work necessary on seven baghouses to strive to meet the MATS compliance deadline for the affected units at Plants Bowen, Hammond, and Wansley.
- Decertification of Plant Branch Units 1 and 2 effective on the Georgia Multipollutant Rule compliance dates of December 31, 2013 and October 1, 2013, respectively, and Plant Mitchell Unit 4C effective as of the date of the Commission’s final order on March 26, 2012.
- Certification of the following three PPAs with Southern Power Company from natural gas-fired facilities—Harris (625 MW), West Georgia (298 MW) and Dahlberg (75 MW). The Dahlberg and West Georgia agreements commence January 1, 2015, and the Harris agreement commences June 1, 2015. All three PPAs end on May 31, 2030.

As described further in Section 1.5 and Section 6, the Company has continued its analysis of the final MATS rule and in this filing has proposed for the Commission’s consideration a final MATS compliance plan. Additional significant developments since the Company’s 2010 IRP are described below.

1.4.1 Georgia Power Advanced Solar Initiative

On September 26, 2012, the Company filed the GPASI in Docket No. 36325 and the Commission approved the program on November 29, 2012. Under the GPASI, the Company will contract for up to 210 MW of solar energy through both distributed and utility scale projects by the end of 2014. Georgia Power expects to purchase up to 120 MW of utility scale solar generation through competitive RFPs. Distributed solar energy will be procured by Georgia Power through the purchase of 90 MW of energy from small and medium-scale solar projects owned by customers and developers. More details regarding the GPASI are contained in Section 10.

1.4.2 Plant McDonough-Atkinson Units 4-6

The Commission approved, in Docket No. 24506, the Company’s Application for Decertification of Plant McDonough-Atkinson Units 1 and 2 and Certification of Plant McDonough-Atkinson Units 4-6. The natural gas fired CC Units 4-6 are now in commercial operation, providing benefits to customers as some of the most efficient units in Georgia Power’s fleet. Unit 6, the

last unit to be placed in-service, achieved commercial operation on October 28, 2012. Additionally, decommissioning activities for the coal-fired Plant McDonough-Atkinson Units 1 and 2 are currently underway. Unit 1, the last operational coal-fired generating unit at Plant McDonough-Atkinson, was retired on February 29, 2012.

1.4.3 Plant Vogtle Units 3 and 4

As approved in Docket No. 27800, Georgia Power and its partners—Oglethorpe Power, MEAG Power, and Dalton Utilities—are adding two nuclear units at Plant Vogtle to meet customers' growing needs and provide important fuel diversity and fuel savings benefits. Addition of the units represents a \$14 billion capital investment in Georgia and is the largest job-producing project in the state, employing approximately 5,000 people during peak construction and creating 800 permanent jobs when the units begin operating. Several milestones have been accomplished and highlights include:

- First combined operating licenses issued by the Nuclear Regulatory Commission (“NRC”);
- 10 million project work hours achieved; and
- Initial Institute of Nuclear Power Operations accreditation of the Plant Vogtle Units 3 and 4 operations training programs.

1.4.4 Wholesale to Retail Actions

On July 27, 2009, the Commission accepted for retail service the Blocks 5 and 6 offer of 178 MW of oil-fired peaking capacity that will become available to retail at different times as the existing wholesale contracts expire, with the total capacity in retail rate base on January 1, 2016. The Commission certified Blocks 5 and 6 on March 5, 2010. On October 10, 2012, the Commission accepted for retail service 250 MW of Block 1 coal-fired capacity that will become available to retail on April 1, 2016 and 312 MW of Blocks 2-4 coal-fired capacity that will become available to retail on January 15, 2015. The blocks were certified on March 26, 2012. More details regarding Wholesale to Retail actions are contained in Section 12.

1.4.5 Reduced Fuel Rates

Since the 2010 IRP, the Company's fuel rates have been reduced on three separate occasions, largely as a result of lower natural gas prices. The addition of the three McDonough-Atkinson

CC units has allowed customers to benefit even more from such prices. The average non-seasonal fuel rates have decreased 24.5% from FCR-21 to FCR-23.

1.4.6 DSM Program Implementation

The Company implemented the seven DSM programs that were certified in the 2010 IRP with a ramp up during the first three years. As part of the program implementation, the Company hired implementation contractors, set up implementation protocols, hired a program evaluation contractor and completed full program evaluations for the seven energy efficiency programs. In 2011, Georgia Power achieved 130.4 gigawatt hours (“GWh”) of gross energy savings as compared to an energy savings target of 104.1 GWh. In 2012, the energy savings target was 203.3 GWh and the Company is likely to achieve about 215 GWh of gross energy savings (final amount has not been determined as of filing). More details regarding the Company’s DSM programs are contained in Section 5 and the 2013 DSM Application.

1.5 THE SUPPLY-SIDE PLAN

Georgia Power’s current supply-side plan, as set forth in the 2011 IRP Update and as further supplemented herein, is sufficient to provide cost-effective and reliable sources of capacity and energy through 2015 and beyond. More details regarding the Company’s supply-side plan are contained in Section 6 and the formal decertification requests are included in the 2013 Decertification Application.

1.5.1 MATS Compliance Strategy Update

As discussed in Section 1.1, the MATS rule is a key driver of the Company’s requests in this proceeding. Released on March 3, 2011, the proposed version of the EPA’s MATS rule (formerly referred to as the “Utility MACT” rule) included stringent emissions limits on coal and oil-fired electric utility steam generating units for acid gases, mercury, and total particulate matter, and included an impracticable compliance deadline. In response to the proposed MATS rule, the Company developed compliance strategies and recommendations that were included in the 2011 IRP Update filed in August 2011. While the 2011 IRP Update proceedings were pending before the Commission, the EPA released its final MATS rule on December 21, 2011, a

mere eight days prior to the filing of the Company's rebuttal testimony and amended application. Given the timing of the rule's release, it was impractical from a technical perspective for the Company to complete a full review of the final rule, including changes from the proposed rule, in order to analyze its impact on the Company's coal- and oil-fired plants on a unit-by-unit basis. Therefore, the Company continued to recommend and the Commission approved expenditures associated with the initiation of construction of baghouses for Plant Bowen Units 1-4, Plant Wansley Units 1 and 2, and Plant Hammond Units 1-4. The Company was ordered to keep the Commission apprised of its evaluation through monthly reports filed at the Commission.

Since that time, Georgia Power has continued an evaluation of the requirements of the final MATS rule and the overall compliance strategy on a unit-by-unit basis for the ten generating units at Plant Bowen Units 1-4, Plant Wansley Units 1 and 2 and Plant Hammond Units 1-4. As a result of its analysis, the Company determined, and has previously notified the Commission in Docket No. 34218, that only Plant Bowen Units 3 and 4 would need baghouses at this time and that MATS compliance can be achieved at Plant Bowen Units 1 and 2, Plant Wansley Units 1 and 2 and Plant Hammond Units 1-4 by installing activated carbon and hydrated lime injection systems and performing precipitator work (an activated carbon and hydrated lime injection system will also be required at Plant Bowen Units 3 and 4 in addition to the baghouses). All units at Bowen, Hammond and Wansley will install scrubber additive systems and evaluate other projects needed to enhance the availability and reliability of existing scrubbers after the MATS compliance deadline.

The final MATS rule contained differences from the proposed rule that allowed the Company to remove five baghouses from its compliance strategy. Chief among these differences was a change in the particulate matter standard between the proposed and final rules. In the proposed rule, the EPA would have imposed a very stringent and complicated limit on particulate emissions that ultimately would have resulted in a unit-specific limit on particulate matter emissions, thereby removing all compliance margin without accounting for natural variation in the operation of a generating unit. Therefore, the only option for compliance under the proposed rule would have been installation of baghouses to attempt to comply under all operating conditions. In the final rule, however, the EPA altered the form of the particulate matter limit such that, while still very stringent, it is a standard limit across all units instead of a unit-specific

limit. The limit also is in a form that allows for additional compliance options to be considered and evaluated on a unit-specific basis as is further explained in the Environmental Compliance Strategy (“ECS”) document in Technical Appendix Volume 2.

Aside from Plant Bowen Units 1–4, Plant Wansley Units 1 and 2, and Plant Hammond Units 1–4 and the coal-fired units for which the Company seeks decertification, additional environmental controls will be required for the remaining coal-fired units to operate on coal after the MATS compliance date of April 16, 2015. Specifically, Georgia Power plans to utilize a bromine additive at Plant Scherer and switch Plant McIntosh 1 to operate on lower-priced Powder River Basin coal (pending a successful test burn and further study). These actions will ensure coal-fired generation remains a cost-effective and reliable part of the fleet, maintaining essential fuel diversity.

Finally, for the remaining coal-fired units that will continue to operate, the Company has concluded that it is not cost-effective to install the environmental controls necessary to enable these units to remain operational on coal. Instead, the Company has found it to be most cost-effective for customers to switch Plant Yates Units 6 and 7 and Plant Gaston Units 1–4 to natural gas as the primary fuel, with coal used as a backup fuel.

For additional information regarding the development of the Company’s MATS compliance strategy, please see the ECS document included in Technical Appendix Volume 2.

1.5.2 Unit Retirements

As described in Section 1.1, the Company’s evaluation of the MATS rule has also led to the conclusion that the most cost-effective compliance option for certain of the Company’s coal- and oil-fired units is retirement. The units for which the Company has made such a determination and seeks decertification in the 2013 Decertification Application are Plant Branch Units 3 and 4, Plant Kraft Units 1-4, Plant McManus Units 1 and 2, and Plant Yates Unit 1-5. These difficult decisions are driven by unfavorable economics, primarily resulting from the scope and cost of environmental controls and limitations required for MATS compliance. In addition, for the reasons stated in Section 1.1, the Company is requesting decertification of Plant Boulevard Units

2 and 3 effective as of the date of the final order in this proceeding and expedited decertification of Plant Bowen Unit 6 by April 16, 2013.

The decision to decertify Plant Branch Units 3 and 4 presented additional challenges that required consideration. Units 3 and 4 are coal-fired supercritical generating units capable of an output of 1,016 MW. Supercritical steam units require a source of steam to assist with the startup of the unit. As the decision to retire Units 3 and 4 became evident, the Company determined that utilizing Plant Branch Unit 1 to provide a source of startup steam for Units 3 and 4 would be more cost effective than purchasing and installing an auxiliary boiler on the site for the short period until these units are decertified. However, as currently drafted, the Georgia Multipollutant rule requires installation of SCR and scrubber on Unit 1 by December 31, 2013, the current Commission-approved decertification date. To allow for a short-term extension of the Unit 1 Multipollutant rule compliance date to allow Unit 1 to provide startup steam for Units 3 and 4, the Georgia Environmental Protection Division (“EPD”) has begun a process to revise the rule. The revision of the rule is intended to align the Multipollutant Rule compliance date for Unit 1 with the date required in the MATS rule, April 16, 2015. As part of this rule revision, the EPD will accelerate the requirement to install controls on Units 3 and 4 from the end of 2015 to April 16, 2015, aligning the compliance dates for those units with the MATS rule as well. Therefore, the Company is requesting an amendment to the decertification date specified in the Commission’s final order in Docket No. 34218 for Plant Branch Unit 1 from December 31, 2013 to coincide with the decertification of Plant Branch Units 3 and 4 by April 16, 2015. This change, if approved by the Commission and the EPD, will provide the most cost effective method to ensure reliable startup of Plant Branch Units 3 and 4 until their retirement.

Additionally, although the long-term decision is to retire Plant Kraft Units 1-4, a one year MATS extension will be requested from the EPD to ensure reliability while necessary transmission improvements in the area are completed.

Table 1.5 summarizes the Company’s supply-side plan:

Table 1.5

Installation of Environmental Controls for MATS Compliance	
Plant Bowen Units 3 and 4	Baghouses along with Activated Carbon and Hydrated Lime Injection systems
Plant Bowen Units 1 and 2	Activated Carbon and Hydrated Lime Injection systems
Plant Wansley Units 1 and 2	Activated Carbon and Hydrated Lime Injection systems
Plant Scherer Units 1-3	Bromine Injection system
Plant Hammond Units 1-4	Activated Carbon and Hydrated Lime Injection systems
Switching Primary Fuels for MATS Compliance	
Plant Yates Units 6 and 7	Coal to Natural Gas
Plant McIntosh Unit 1	Bituminous Coal to PRB Coal; Activated Carbon and Dry Sorbent Injection systems
Plant Gaston Units 1-4	Coal to Natural Gas
Biomass Conversion	
Plant Mitchell Unit 3	Coal to Biomass
Requested Decertifications and Applicable Dates	
Plant Branch Units 3 and 4	By the MATS compliance date of April 16, 2015
Plant Yates Units 1-5	By the MATS compliance date of April 16, 2015
Plant McManus Units 1 and 2	By the MATS compliance date of April 16, 2015
Plant Kraft Units 1-4	1 year past the MATS compliance date (by April 16, 2016)
Plant Boulevard Units 2 and 3	Date of the final order in this proceeding
Plant Bowen Unit 6	By April 16, 2013

The Selected Supporting Information section of Technical Appendix Volume 2 includes certain costs the Company will incur to implement a portfolio of renewable demonstration projects. Sections 10.3.3, 10.3.4, 10.3.6, and 10.6.1 of the Main Document of the IRP contain descriptions

of these projects. The Company believes that it is appropriate to review and approve these costs in the overall context of this IRP proceeding.

1.6 THE DEMAND-SIDE PLAN

The Company's current DSM portfolio consists of demand response programs, energy efficiency programs, pricing tariffs, and other activities. The Company projects that by 2016 these programs will reduce peak demand by approximately 2,000 MW. This load reduction represents more than 12 percent of the Company's current load.

In accordance with the final order in the 2010 IRP, the Company has continued to work closely with the DSM Working Group through the use of the Nine Step process for DSM program development. The Company prepared an updated energy efficiency technology catalog, completed and filed an energy efficiency potential study, and conducted a comprehensive analysis of potential DSM programs with the assistance and input of the DSM Working Group.

The recommended DSM action plan includes seeking Commission approval for a certificate for one new DSM program, amending the certificate of three currently certified DSM programs, decertifying one DSM program (though the program activities will be subsumed by an existing program) and updated program economics for the remaining certified DSM programs in the Company's 2013 DSM Application. The Company also intends to continue the Power Credit residential program, which was previously certified in Docket No. 6315.

However, the Company notes that avoided cost savings are lower, which has had a significant and negative impact on the economics of the Company's current and proposed DSM programs. As discussed in Section 5, Total Resource Cost ("TRC") Test results declined and Ratepayer Impact Measure ("RIM") Test results worsened, causing concerns for the Company in its efforts to balance the economic benefits these programs provide for participating customers with the rate impacts to all customers within a given class caused by the programs. Nevertheless, the Company supports the continuation of the energy efficiency programs approved in the 2010 DSM Certification filing and also seeks to certify a Small Business program targeted toward a hard to reach customer sector. The Company plans to continue to monitor program costs and

economics during 2014 - 2016 and will be prepared to modify programs in the future if the significant upward pressure on rates continues.

Summary information for two alternative DSM sensitivity cases is also included in this filing. One alternative sensitivity case, deemed the “Advocacy Sensitivity Case,” presents a potential set of DSM programs designed around the recommendations from some members of the DSM Working Group to achieve 10 year cumulative energy savings of 9.5 percent. The other alternative sensitivity case represents the “Aggressive Sensitivity Case” that was outlined in the Nine Step process.

1.7 THE PRICING PLAN

The Company will continue its strategy of developing and promoting rates that give customers pricing signals that encourage peak demand reduction and load shifting. Innovative programs developed by Georgia Power (such as our Real Time Pricing (“RTP”) program, Demand Plus Energy Credit (“DPEC”) and Time of Use (“TOU”) rates) have been effective in reducing the peak demand for electricity.

Georgia Power completed installation of the Advanced Metering Infrastructure (“AMI”) “smart” meters in 2012. The Company leverages the AMI investment by promoting rates that send strong, clear pricing signals such as the Time of Use-Residential Energy Only (“TOU-REO”) and Time of Use Plug-in Electric Vehicle (“TOU-PEV”) rates. The Company’s promotions will continue to focus on helping customers save money and energy by reducing usage or shifting loads from the on-peak time period.

Georgia Power also offers the Time of Use-Fuel Cost Recovery (“TOU-FCR”) rider. TOU-FCR was made permanent and expanded in 2012, and is now available on a voluntary basis to all customers on TOU base tariffs. Additionally, the Time of Use-Fuel Cost Recovery Three Part (“TOU-FCR-TP”) pilot rate was introduced in 2012. The TOU-FCR-TP pilot rate is available to customers on the TOU-PEV and Time of Use-Medium Business (“TOU-MB”) rates. TOU-FCR rates will further strengthen price signals seen by customers on time of use rates.

1.8 THE ENVIRONMENTAL PLAN

The ECS document included in Technical Appendix Volume 2 reflects the most recent regulatory developments and related strategies to ensure that the Company's operations continue to meet all local, state and federal environmental laws and regulations. The ECS establishes a general direction for compliance and allows for individual decisions to be made based upon specific information available at the time. This approach is necessary to maintain the flexibility to match a rapidly changing regulatory compliance environment. In the 2011 IRP Update, the ECS contained a strategy based heavily on the most impactful environmental rule that had been proposed at that time, the EPA's MATS rule. The ECS in the current filing has been updated to reflect the Company's compliance strategy for the final MATS rule and other existing and expected environmental requirements.

The Company anticipates that it will seek, and the Commission may approve, a modified form of the current ECCR tariff in the 2013 base rate case. Therefore, the Company believes the related environmental costs to be proposed for recovery through the ECCR tariff should be reviewed and considered in the overall context of this IRP. The costs which the Company seeks to have approved are more specifically described in the Selected Supporting Information section of Technical Appendix Volume 2. These costs are generally capital and O&M costs necessitated by federal and state environmental laws and regulations.

1.9 RELIABILITY

Over the next several years, Georgia Power has sufficient resources to maintain an adequate planning reserve margin given anticipated demand of its customers and the current regulations impacting electric generating units. Given the uncertain nature of forecasts and of future regulations, the Company will continue to constantly evaluate its resource needs and will respond as necessary to ensure the reliability and economics of the Georgia Power system. Georgia Power and the System maintain adequate reserve margins in their respective plans to ensure reliable and cost-effective service to their customers.

1.10 RESERVE MARGINS

After an analysis of load forecast and weather uncertainty, the cost of expected unserved energy, as well as the current and near-term projected generation reliability of the System, the Company will maintain a target system planning reserve margin of 15 percent in the long term, which is very near the minimum total cost but carries less risk than the absolute minimum cost point. As demonstrated in the Reserve Margin Study included in Technical Appendix Volume 1, the absolute minimum cost point rose slightly because of updates to certain key assumptions shown in the bullet points below, although not enough to justify any change to the target reserve margin. For the short-term horizon, the Company will maintain a 13.5 percent system planning reserve margin guideline, but may periodically review the availability and cost of resources in the market and adjust short-term resource procurement decisions accordingly.

The updates to certain key assumptions that affected the results of this Reserve Margin Study are as follows:

- The economic carrying cost of a CT in 2012 dollars decreased by less than 5 percent. A lower CT cost results in a higher reserve margin for the minimum cost point.
- The Southern Electric System average peak equivalent forced outage rate (“EFOR”) has increased slightly since 2009. Higher EFOR results in more projected reliability purchases and more EUE, which results in a slightly higher reserve margin for the minimum cost point.
- An outage cost survey of Georgia Power and Mississippi Power customers was completed in 2011 by Freeman Sullivan & Company in accordance with the Commission’s 2010 IRP Order. The cost of EUE from this survey is substantially higher than in previous studies. Since EUE is so infrequent, even at lower reserve margins, this change only slightly increased the reserve margin for the minimum cost point. For results of the study, see the EUE Study in Technical Appendix Volume 1.

1.11 THE DEMAND AND ENERGY FORECASTS

A twenty-year forecast of energy sales and peak demand was developed to meet the planning needs of Georgia Power. The Budget 2013 Load and Energy Forecast (“Budget 2013 Forecast”)

includes the retail classes of residential, commercial, industrial, MARTA, and governmental lighting. Effective January 1, 2013, Georgia Power is no longer serving the city of Hampton wholesale requirements load.

The peak demand forecast for the Budget 2013 Forecast has been adjusted to account for the effects of RTP customers' response, expected cogeneration, and residential and commercial demand side management programs.

A detailed discussion of the revised territorial energy and demand forecasts is set forth in the Budget 2013 Forecast in Technical Appendix Volume 2.

1.12 TRANSMISSION PLAN

This IRP includes the Company's ten-year transmission plan, which identifies the transmission improvements needed (based upon current planning assumptions) to maintain a strong and reliable transmission system. The development of this plan is conducted in accordance with the System transmission planning guidelines and with North American Electric Reliability Council ("NERC") planning standards. Along with the ten-year plan, Georgia Power has included a comprehensive and detailed bulk transmission plan of the Georgia Integrated Transmission System as required by the amended rules adopted by the Commission in Docket No. 25981. Additional transmission information is also available as required by Docket No. 31081.

1.13 INTEGRATED RESOURCE PLAN

The Company's 2013 IRP reflects the following:

- Purchase of 998 MW of capacity and energy certified by the Commission in Docket No. 34218 on March 26, 2012, with 373 MW available beginning January 1, 2015 and the remaining 625 MW available beginning June 1, 2015;
- Retirement of Plant Branch Units 3 and 4, Plant Yates Units 1-5, and Plant McManus Units 1 and 2 effective with the MATS compliance date, retirement of Plant Kraft Units 1-4 by one year past the MATS compliance date, retirement of Plant Boulevard Units 2 and 3 effective as of the date of the final order in this proceeding, and retirement of Plant Bowen Unit 6 by April 16, 2013;

- Retirement of Plant McDonough-Atkinson Units 1 and 2 by 2012 and the addition of Units 4, 5, and 6 by 2012 for a net addition of approximately 2,003 MW as certified by the Commission in Docket No. 24506;
- Retirement of Plant Branch Unit 1 by April 16, 2015, Plant Branch Unit 2 effective October 1, 2013, and Plant Mitchell Unit 4C effective March 26, 2012, the date of the Commission's final order in Docket No. 34218;
- A switch to natural gas as the primary fuel for Plant Yates Units 6 and 7 and Plant Gaston Units 1-4;
- A switch to PRB coal for Plant McIntosh and corresponding derate;
- Addition of two new nuclear units at Plant Vogtle (Units 3 and 4) for a combined increase in capacity of approximately 1,007 MW by 2018;
- Conversion of Plant Mitchell Unit 3 from coal to biomass as certified by the Commission in Docket No. 28158;
- Addition of 210 MW of solar resources from the GPASI as approved by the Commission on November 29, 2012 in Docket No. 36325;
- Continuation of existing DSM programs, modification of certain existing DSM programs, decertification of one existing DSM program, and addition of one new DSM program as reflected in the 2013 DSM Application filed concurrently in Docket No. 36499;
- Unit Retirement studies of certain generating facilities that consider a range of scenario cases assuming certain fuel and carbon views through a matrix approach and support the Company's MATS compliance strategy;
- Capacity Mix Studies that show optimal capacity resource additions for the base case IRP assuming current regulations and no carbon emissions prices as well as results from scenarios with alternative fuel price forecasts and carbon price assumptions; and
- Updated load and energy forecasts as well as an updated fuel forecast.

Furthermore, the IRP was tested under a range of sensitivity analyses to ensure that it will continue to meet customer needs if future conditions change. The different assumptions used in the sensitivity analyses are detailed in Section 6.5.3.

1.14 CONCLUSION

In summary and as previously stated in Section 1.1, the Company seeks approval of:

- 1) Its 2013 Integrated Resource Plan and the associated Action Plan;
- 2) Decertification of Plant Branch Units 3 and 4, Plant Yates Units 1-5, and Plant McManus Units 1 and 2 effective by the MATS compliance date of April 16, 2015, decertification of Plant Kraft Units 1-4 one year past the MATS compliance date (by April 16, 2016), decertification of Plant Boulevard Units 2 and 3 effective as of the date of the final order in this proceeding, and approval of expedited decertification of Plant Bowen Unit 6 by April 16, 2013 as specified in the 2013 Decertification Application;
- 3) A switch to natural gas as the primary fuel for Plant Yates Units 6 and 7 and Plant Gaston Units 1-4;
- 4) An amendment of the decertification date specified in the Commission's final order in Docket No. 34218 for Plant Branch Unit 1 from December 31, 2013 to coincide with the decertification of Plant Branch Units 3 and 4;
- 5) A certificate of public convenience and necessity for one new DSM program, a certificate amendment for three previously certified programs, decertification of one DSM program, and approval of updated program economics for all other previously certified energy efficiency DSM programs as further specified in the 2013 DSM Application in Docket No. 36499;
- 6) Reclassification of the remaining net book values of Plant Branch Units 3 and 4 and Plant Boulevard Units 2 and 3 as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 31958;
- 7) In the event the Commission does not approve the expedited decertification of Plant Bowen Unit 6, reclassification of the remaining net book value of Plant Bowen Unit 6 as of its respective retirement date to a regulatory asset account and the amortization of such regulatory asset account ratably over a period equal to the unit's remaining useful life approved in Docket No. 31958;
- 8) Amortization of approximately \$38 million of Plant Branch Units 3 and 4 and approximately \$14 million of Plant Yates Units 6 and 7 environmental CWIP (which has

been reclassified as a regulatory asset in accordance with the Commission's Order in Docket No. 31958) ratably over a three year period beginning January 2014;

- 9) Reclassification of any unusable M&S inventory balance remaining at the unit retirement dates to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 31958 for recovery over a period to be determined by the Commission in the Company's next base rate case following the unit retirements;
- 10) The capital costs the Company will incur for a portfolio of certain renewable demonstration projects (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 2; and
- 11) The capital and O&M costs (but not yet the recovery) of measures taken to comply with existing government-imposed environmental mandates, as set out in the Selected Supporting Information section of Technical Appendix Volume 2.

2 – INTEGRATED RESOURCE PLANNING PROCESS OVERVIEW

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SECTION 2 - INTEGRATED RESOURCE PLANNING PROCESS OVERVIEW

The development of an IRP for Georgia Power is part of a continuous planning process. Many different disciplines and areas of expertise from Georgia Power and Southern Company Services (“SCS”) are incorporated in this planning process. This process provides for an orderly and reasoned framework under which both supply-side and demand-side option evaluations are compared on an equitable basis to develop a plan that provides for reliable and economic electric energy to serve customers’ needs over the planning horizon.

The Company developed a base case IRP using a combination of potential demand- and supply-side generation resources to meet the needs of customers as determined in the base case load and energy forecast. This base case plan represents an evaluation of the planning period with current laws and regulations.

For the 2013 IRP, the Company is presenting the results of multiple scenario planning cases that evaluate the impacts of three different fuel price views as well as three different carbon views, each estimating the costs of potential carbon prices that represent additional pressure on carbon dioxide-emitting generation (e.g., greenhouse gas legislation or additional greenhouse gas regulation). Each scenario planning case is a separate and fully integrated resource plan and provides valuable insights into the potential impacts of different combinations of fuel prices and carbon prices over the planning period.

Federal greenhouse gas legislation, if passed, or further development of additional greenhouse gas regulation, if promulgated by the EPA, will have a significant impact on national economic activity, fuel prices, and the electric utility industry. Given the differences in the electric generation fuel mix across the U.S., greenhouse gas legislation and/or regulation is also predicted to have large and disproportionate regional impacts, with particularly negative impacts for the southeastern U.S. due to its greater use of coal-fired electric generation compared to other regions. In order to evaluate these interactive and regional impacts, a national economic model was employed to evaluate the impacts of different fuel price forecasts and projections of carbon prices on national and regional economic activity.

This national economic model was also used to estimate the impacts of different carbon prices on the price of fuels, particularly natural gas, and to estimate the changes to the electric generation fleet across the U.S. that result from the scenario-specific prices of carbon and fuel. These impacts were extended to develop specific load and energy forecasts for each scenario. These load and energy forecasts were then used as the basis for developing a reliable and economic combination of potential demand- and supply-side generation resources to meet the needs of customers for each scenario.

2.1 CRITERIA FOR RESOURCE SELECTION

When a need for new capacity exists, the Company evaluates a combination of demand-side and supply-side resources to meet the need in an economical manner. The principal criterion for the development of the IRP is to maintain customer value — now and in the future. Customer value is maintained when the benefits of the services provided to customers exceed the cost of those services.

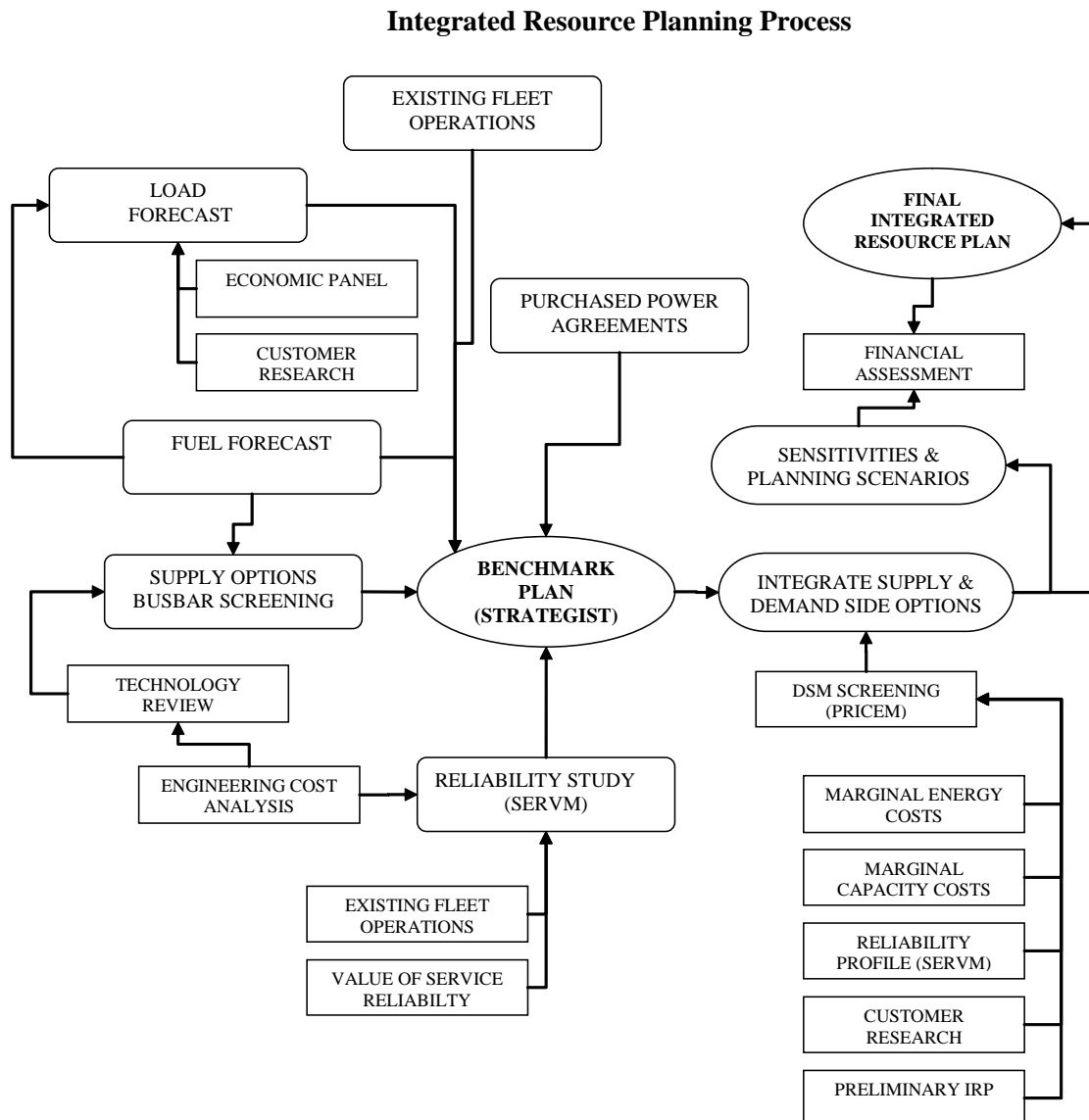
The best IRP is one that provides a high level of customer value while anticipating a broad range of potential changes. Therefore, Georgia Power considers additional objectives in the development of the IRP. These include:

- * **Flexibility** - Can the plan be altered if the future is different than expected?
- * **Reliability** - Does the plan provide reliable service for all customers?
- * **Long-Term Viability** - Will the plan meet customer needs over the long term?
- * **Environmental** - Does the plan ensure compliance with environmental regulations?
- * **Risk** - Does the plan appropriately mitigate the risk of future changes in conditions?
- * **Shareholder Value** - Will the plan provide shareholders with a fair return on their investment?

2.2 OUTLINE OF THE PROCESS

The detailed process by which the IRP is developed is shown in Figure 1, and the components of this process are described below. This process is an integrated process where both the supply-side and the demand-side programs are evaluated simultaneously rather than independently.

Figure 1 - Detailed Integrated Resource Planning Process



The result of this process is the addition of demand- and supply-side options to serve customer needs in an economical manner considering reliability, flexibility, and risk. Georgia Power's

IRP process includes inputs from: (1) the Fuel Forecast; (2) the Economic Forecast; (3) Generation Technology Screening; (4) the Load and Energy Forecast; (5) the Reserve Margin Study; (6) demand-side program assessments; (7) existing resource screenings; (8) the Technology Cost Development Study; (9) the mix integration; and (10) the financial analysis and review steps.

2.2.1 Development of the Benchmark Plan

The left portion of Figure 1 shows how various inputs, such as customer preferences, reliability standards, technology updates, economic projections, and the latest load and energy forecast, feed into the development of a benchmark supply-side plan. The development of these inputs is described below.

2.2.1.1 Data Inputs

Fuel Forecast — The System develops both short-term (current year plus two) and long-term (year four and beyond) fuel and allowance forecasts. Short-term forecasts are updated monthly as part of the System’s fuel budgeting process, and marginal pricing dispatch procedures. The short-term forecasts are overseen by SCS Fuel Services. The long-term forecasts are initially developed in early spring of each year for use in system planning activities. The long-term forecasts are overseen by the System’s Planning Coordination Team. CRA International (“CRA”) is the modeling vendor used by the System to develop the long-term forecasts. The development of the long-term forecasts is a highly collaborative effort between CRA and the System (see Appendix I in the Resource Mix Study found in Technical Appendix Volume 1).

Economic Forecast — Moody’s Analytics’ macroeconomic forecast is the basis for inflation and cost of capital estimates. Moody’s Analytics developed a forecast of economic variables and demographic statistics for the state of Georgia. Key descriptive variables from the economic and demographic forecast of Georgia were used to produce the Budget 2013 Load and Energy Forecast (see Technical Appendix Volume 2).

Generation Technology Qualitative and Economic Screening — Feasibility studies for 39 generation technologies were qualitatively screened by technology experts in SCS Research and Environmental Affairs. Various mature and emerging generating technologies were evaluated

for the feasibility of deployment within the System. For all technologies determined to be viable, recommendations were made for further consideration by declaring the “Status” of the respective technologies as “retained for further screening”. This process produced a select list of generating technology types that may be candidates for future plant additions.

Next, a preliminary, quantitative, economic and environmental screening evaluation was conducted utilizing a busbar life-cycle screening analysis. Busbar analysis compares total capital and operating costs of different types of generating technologies across a range of capacity factors. Busbar screening considers capital, fixed and variable O&M, fuels, and environmental-related costs and yields a comparison of the relative economics. The most promising technologies are subsequently reviewed in more detail, producing a recommendation of those types of generating units that are likely to be good candidates for inclusion in developing the final supply- side plan (see Section 6.4.2.).

Load and Energy Forecast — The Budget 2013 Forecast was started in the spring of 2012 and finalized in the fall of 2012. The load and energy forecasting process uses a combination of end-use and econometric analyses. The forecast is based on projections of economic growth, migration into the state, appliance efficiencies, competing fuel costs, and a variety of other projections. The principal sources of these projections are economic forecasting services, customer surveys, and computer models used by the Company. The forecast process is explained in detail in Section 3 of this document and in Technical Appendix Volume 2.

Reserve Margin Study — The retail operating companies currently use a 15 percent target system reserve margin guideline for long-term resource planning. This guideline was developed using a combination of mathematical models and studies, industry experience, and system operations input, and was approved in the most recent IRPs. Economic evaluation is a key component of setting the reserve margin target. An updated reserve margin study was recently completed for the 2013 IRP, and it affirmed the 15 percent longer-term system planning reserve margin target provides the appropriate balance between reliability and cost (see the Reserve Margin Study in Technical Appendix Volume 1).

Technology Cost Development Study — Current estimates are needed for cost, spending curves, emissions, and operating characteristics of the types of new generating units most likely

to be added to the system. Natural gas-fueled simple-cycle CT and CC units are the generating technologies likely to be added to the system in addition to renewable generation, new nuclear, and coal-fired plants with carbon capture and sequestration. Also, the CT cost is included in the marginal capacity cost used in evaluating demand-side options, existing unit changes, and load building programs. These estimates are inputs into a computer model that utilizes dynamic programming techniques to develop an optimum schedule of the types of capacity needed throughout the planning period.

2.2.1.2 Mix Process

A key part of the benchmark plan in Figure 1 is the determination of the mix of generating capacity types that economically and reliably serves the projected customer load. The mix process combines all of the information represented by the arrows pointing to the benchmark plan. The mix process uses dynamic programming techniques to determine the least-cost combination of units that will meet reliability constraints.

One of the first steps in developing this portion of the IRP is a least-cost analysis that minimizes the net present value of the revenue requirements for the moderate (or base case) level of customer load in order to develop the benchmark plan.

The result of this effort is the creation of the benchmark plan. The preliminary supply-side plan will be used as the base plan for the demand-side integration process. The final supply-side plan (or base case) includes the results of the demand-side analysis (see Figure 1, above).

The key model used in the mix process is Strategist®. Strategist® employs a generation mix optimization module named PROVIEW™ (see Section 14, Attachment 14.1). Strategist® is used by approximately 70 other electric utilities. The major inputs of PROVIEW™ are: (1) future generating unit characteristics and capital cost; (2) the capital recovery rates necessary to recover investment cost; (3) capital cost escalation rates; and (4) a discount rate.

2.2.2 Assessment of Demand-Side Programs

Georgia Power identifies, screens, and assesses potential demand-side programs applicable to its service territory for inclusion in the IRP. This process uses a marginal cost approach to compare

the costs with the benefits of each demand-side program. Generation capacity and energy, transmission, distribution, and other costs and benefits are evaluated. The model used to estimate marginal energy cost (PROSYM) is the source of the marginal energy cost used in the model to evaluate DSM programs (PRICEM). These same marginal costs are used extensively in other supply-side evaluations associated with the IRP. Also, technology availability, market characteristics, customer acceptance, and customer response are considered in estimating the potential success, impacts, and costs of the programs. The process is described more fully in Section 5.

2.2.3 Existing Resource Evaluation

Georgia Power analyzes potential increases in output from existing generating units using marginal cost techniques similar to those used to analyze demand-side programs. As with DSM, the model used to estimate marginal energy cost (PROSYM) is the source of the marginal energy cost used in the model to evaluate existing resources.

2.2.4 Integration and Development of the IRP

The integration step requires a re-examination of the need for generation additions identified in the benchmark plan as a result of including demand-side programs. After consideration of risk and uncertainty through sensitivity analyses and application of reasonable judgment, the 2013 IRP is finalized.

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**3 – BUDGET 2013
LOAD AND ENERGY
FORECAST**

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SECTION 3 - BUDGET 2013 LOAD AND ENERGY FORECAST

3.1 GENERAL FORECASTING AND ECONOMICS OVERVIEW

The Budget 2013 Load and Energy Forecast (“Budget 2013 Forecast”) is for Georgia Power. Unless otherwise noted, all data, figures, and statistics include both Georgia Power Company and the former Savannah Electric and Power Company, which was merged into Georgia Power Company effective July 1, 2006.

The twenty-year forecast of energy sales and peak demand has been developed to meet the planning needs of the Company. The Budget 2013 Forecast includes the retail classes of residential, commercial, industrial, MARTA, and governmental lighting. The City of Hampton, included in the previous forecasts as a wholesale customer, is no longer served by Georgia Power. The baseline forecast was started in the spring of 2012 and completed in the fall of 2012.

The nation’s recovery from the Great Recession has been full of promise that, for the most part, has not yet materialized. Georgia’s economic recovery has been similar, but with a lag and, by some measures, weaker than the nation’s. For the past few years, the economy has shown signs of strength early in the year only to weaken by year end. Since the recession ended in mid-2009, real GDP has grown at an average annual rate of 2.3%, while Georgia’s corresponding real GSP has grown an average of 2.2% over the same period. The nation’s unemployment rate has fallen from its peak of 10.0% in 2009 to 7.8% as of December 2012, while the state’s rate, which peaked at 10.5% in 2010, has dropped to 8.6% as of December 2012. Both the state and nation would show significantly better numbers if the recovery had been typical of recoveries following previous recessions.

The slow recovery is reflected in Georgia Power’s energy sales statistics for the past few years. Weather normalized total energy sales for 2012 were nearly 0.5% below the prior year’s level and remain more than 3.3% below the previous peak in 2007. The major drop since the recession has been in industrial sales, which remain almost 9.2% below their pre-recession level on a weather-normalized basis in spite of healthy growth in 2010 and moderate growth in 2011.

In 2012, commercial and residential energy sales levels were 1.2% below and 0.3% below 2007 levels, respectively.

Although underperforming for the past few years, Georgia's economy is expected to regain strength over the next several years. Surveys show that the state remains an attractive place to do business. Recent announcements of companies' plans to locate or expand in the state include those by Baxter International and Caterpillar which are expected to bring 2,900 jobs to the state. Living costs also remain attractive relative to many states. The demographic forces that once propelled the state to near the top of the economic growth league should strengthen once home price adjustments break the housing logjam that nearly halted net migration. As the economy improves, energy sales will follow suit. Total energy sales are currently projected to grow at an average annual rate of 1.2% from 2013 to 2020. Residential sales will be the strongest of the three major customer classes with growth projected to average 1.4% per year; industrial and commercial are projected to average 1.2% and 1.1%, respectively. Peak demand is projected to grow an average of 1.5% per year from 2013 to 2020.

3.2 FORECAST ASSUMPTIONS AND METHODS

The Budget 2013 Forecast assumptions were developed through a joint effort of Georgia Power and SCS. The forecast was developed through careful consideration and methodical organization of key demographic and economic variables that have been demonstrated to be significant indicators of energy consumption. Major assumptions included the economic outlook for the U.S. and Georgia, energy prices, and market profiles for class end uses.

The economic forecast gives a description of the economy for the next 20 years and includes many elements of the economy, such as gross product, population, employment, commercial building square footage, and industrial production. The economic forecast for Budget 2013 Forecast was obtained from Moody's Analytics, a national provider of economic data and forecasts.

The economic models used to produce both short and long-term energy and demand forecasts test a variety of economic and demographic variables as drivers of energy use. Retail prices for electricity and natural gas, for example, are drivers of energy use. The short-term forecasting

models incorporate retail electricity prices, while the long-term models allow both electricity and gas prices to affect the purchasing decisions of customers. Price projections of the alternative fuels that energy-consuming devices use to support a consumer need, business purpose, or industrial process are developed from internal processes so that device choice through consumer behavior can be modeled.

Weather, income, employment, historical load data, and industry standards for electrical equipment are among the other variables used in the forecasting models. Both the short-term and the long-term energy models are based on “normal” weather - the twenty-year average of Cooling Degree Days (“CDD”) and Heating Degree Days (“HDD”).

Short-term energy projections are based on linear regression models developed for the various energy classes. The details of these regression models can be found in Section 4 of the Budget 2013 Forecast in Technical Appendix Volume 2.

The long-term models for the major classes are end-use models. The Residential End-Use Energy Planning System (“REEPS”) model is used for the residential class, the Commercial End-Use Model (“COMMEND”) is used for the commercial class, and the Industrial End-Use Forecasting Model (“INFORM”) is used for the industrial class. These are discussed in greater detail in Section 5 of the Budget 2013 Forecast included in Technical Appendix Volume 2.

Governmental lighting and MARTA forecasts are based on econometrics and information from Georgia Power field personnel.

The results of the short-term and long-term models are integrated into a unified forecast. In the Budget 2013 Forecast, the short-term forecast results were used for 2013 through 2015 and long term forecast results were used for 2016 through 2032. Additional information on methodology can be found in Section 3 of the Budget 2013 Forecast in Technical Appendix Volume 2.

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4- COMPARISON OF THE FORECAST WITH EXISTING RESOURCES

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SECTION 4 - COMPARISON OF THE FORECAST WITH EXISTING RESOURCES

4.1 SYSTEM AND GEORGIA POWER RESOURCES

The System carries reserves in order to maintain a desired level of reliability in the face of many uncertainties, the most significant of which are load growth, weather, and generating unit outages. The current System long-term planning target reserve margin requirement is 15 percent of the total System load. In most years, the System operating companies peak at different times. This results in a lower System peak than the sum of each operating company's peak demands. Due to this load diversity, each operating company can carry lower reserves (approximately 13.5 percent) and still maintain the target planning reserve margin of 15 percent for the System. As a member of the System, Georgia Power shares reserves with the other operating companies. Georgia Power and the System are currently projected to have adequate reserves through 2022. Without reserve sharing, the Company's first year of capacity need is 2021. Georgia Power will provide an adequate and cost-effective level of reliability to its customers.

See Table 4.1.1, Table 4.1.2 and Figure 4.1 in the IRP Main Document Reference Tables section of Technical Appendix Volume 1 for additional details.

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5 – DEMAND-SIDE PLAN

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SECTION 5 - DEMAND-SIDE PLAN

This section summarizes the process used to assess demand-side resources for Georgia Power's 2013 IRP filing. Included in this section are:

- A review of significant events since the Company's 2010 IRP filing that are relevant to the assessment and screening of demand-side resources;
- A discussion of newly proposed and expanded DSM programs and activities;
- A discussion of the regulatory treatment of DSM program costs and the Additional Sum; and
- A presentation of the economic results of DSM programs for this IRP.

The identification and evaluation of demand-side resources for inclusion in this IRP involves market considerations, such as customer acceptance and applicability, customer economics, and electric supply system economics. The process uses marginal electric supply costs in the analysis. The Company followed the process outlined in the Commission's IRP Rules and the Nine Step process outlined in the 2010 IRP Order which is discussed in more detail in later sections of this filing.

5.1 REVIEW OF SIGNIFICANT EVENTS SINCE PREVIOUS IRP FILING

Since the Company's 2010 IRP filing, certain events have affected the screening of demand-side resources. These events are described below:

5.1.1 2010 IRP Filing Approval

In the 2010 IRP Order, the Commission approved and certified seven of the Company's proposed DSM programs at an agreed upon three-year ramp up to the Commission Staff's proposed annual participation levels. The 2010 IRP Order also approved program implementation plans for the following programs:

Residential Programs:

- Lighting & Appliance
- New Home
- Home Energy Improvement
- Refrigerator/Freezer Recycling

- Water Heating

Commercial Programs:

- Custom Incentive
- Prescriptive Incentive

Additionally, as part of the implementation of the seven new programs, a program evaluation plan was developed and filed with the Commission in 2011, and the program evaluations were subsequently completed in 2012.

5.1.2 Program Evaluation Results

As part of the stipulated agreement between the Company and the Commission included in the 2010 IRP Order, each of the seven newly certified DSM programs were to have a process and load impact evaluation performed prior to the 2013 IRP. Nexant was selected by Georgia Power to perform the program evaluations. Program evaluations were completed and filed in December 28, 2012. The results of the program evaluation were considered in the development of the 2013 IRP and will be considered in future DSM program plans.

5.1.3 2013 IRP Demand Side Management Working Group (“DSMWG”) Meetings

The Company met with the DSMWG four times in 2011 and four times in 2012 in accordance with the Nine Step process approved by the Commission in the 2010 IRP Order. Additionally, the Company met with sub-committees twice in 2012 to discuss DSM program concepts and to discuss modeling of a DSM case proposed by certain members of the DSMWG. Finally, the Company conducted several telephone conference calls and shared data with the DSMWG leading up to the 2013 IRP filing.

5.1.4 2013 Nine Step DSM Planning Process

As part of the 2010 IRP Final Order, the Commission approved the Nine Step DSM planning process that guided the development of the Company’s 2013 IRP DSM plan.

Specifically, the Nine Step process stated:

1. *Georgia Power, using an RFP process, will select a third party consultant to assist in the Technology Catalog update, research active programs nationally, and assist in developing proposed programs.*
2. *Georgia Power will utilize a technical and economic potential study for Georgia Power's service territory to assist in targeting DSM programs in the areas where the highest market potential exists. For the 2013 IRP, Georgia Power will file a new energy efficiency potential study one year in advance of the 2013 IRP filing.*
3. *Georgia Power, along with its consultant, will update the DSM Measures in the Technology Catalog for the purpose of producing the energy efficiency potential study. The starting point will be the 2010 IRP Technology Catalog. Additional technologies will be added once Georgia Power's consultant is chosen and begins its work. The Company will then use the results of the potential study to identify a list of DSM measures that passes the TRC test to be used in program plans. This list of measures will then be presented to the DSMWG. The Company will work closely with members of the DSMWG through this process, and DSMWG members may also propose new measures to be added at any point in the measure evaluation process.*

For each DSM measure that passes the TRC test included in the Technology Catalog, the utility shall provide all members of the DSM Working Group with the following information:

- (i) A brief description of the measure;*
- (ii) Measure costs and the exact source for these costs;*
- (iii) Measure kW and kWh load impacts and the exact source for such load impacts;*
- (iv) The forecast of electric and other avoided costs used to value measure or program savings;*
- (v) Measure useful life and the exact source for measure life data;*
- (vi) Measure levelized cost per lifetime kWh saved (for energy efficiency measures only);*
- (vii) Size of the eligible market;*
- (viii) Forecast of achievable market penetration;*
- (ix) Current saturation of the energy efficiency or demand response measure and the source of this data;*
- (x) Assumptions on participant benefits, if any, other than electricity savings; and*
- (xi) Any other supporting data deemed pertinent by the utility.*

The update of the Technology Catalog will be completed by January 1, 2012.

4. *Once the Technology Catalog is updated, Georgia Power will propose the bundling of measures into programs. Georgia Power, along with its consultant, will prepare a proposed program presentation for review by the DSMWG. Any other member of the DSMWG may propose programs as well. The DSMWG will meet to facilitate sufficient discussions on the programs to be evaluated. An electronic version of this presentation will be provided to the DSMWG at least two weeks prior to the in-person meeting where this information will be presented.*

5. *As part of the program design development, the Company intends to collect and share customer data/feedback with the DSMWG. In the event that the Company reasonably determines that certain data/feedback cannot be shared with the DSMWG, the DSMWG will be made aware of that withholding and the reasons for that withholding. This could include information obtained from surveys, customer focus groups, impact and process evaluations, Georgia Power Account Representatives, etc.*
6. *Once the Company determines which programs are to be analyzed, it will perform an economic screening of the programs in greater detail using the EnerSim and PRICEM models. For each program proposed by a member of the DSMWG that Georgia Power decides not to analyze, Georgia Power shall provide to the DSMWG justification for its decision. The economic screening will include RIM, participants test ("PT"), total resource costs tests ("TRC"), and the Program Administrator Test for use in program design development. The results of the economic screening will be shared with the DSMWG for discussion. This economic screening will be presented to the DSMWG no later than third quarter of 2012.*
7. *Attempts to reach consensus and finalize all programs to be proposed for implementation in the 2013 IRP must be completed by third quarter of 2012 in order to allow the Resource Planning group adequate time for inclusion in their process. Preliminary cost-effectiveness tests using PRICEM for revenue and avoided costs inputs will be developed for each program. These programs will be divided into programs that are passive (energy efficiency programs whose response is not controlled) versus active (demand response programs that are generally under dispatch control of the utility). Load reductions associated with passive programs will be used to adjust the load and energy forecast. Capacity associated with active programs will be modeled as resources. This information will be evaluated as two different system configurations with a base case without any new DSM (the base case would include the effects of continuation of existing DSM programs) and a Company DSM change case with both passive and active new DSM.*
8. *As part of the sensitivity analysis, the Company will also analyze at least one aggressive DSM change case developed with the assistance of the DSMWG. The aggressive DSM change case(s) could include technically viable and economically efficient DSM programs and resources that were not included in the Company DSM change case. The aggressive DSM change case(s) could also include higher penetrations of the DSM programs proposed in the Company DSM change case.*
9. *The Company will use the difference in costs between the base case and the DSM change case configurations to determine the avoided generation cost impact of the DSM programs in each DSM change case. As the final step, the cost effectiveness tests mentioned in item 6 (above) will be calculated based on the inputs and adjustments from the system tools. Revenue impacts will be based on current rates and escalations based on the Company's financial projections adjusted for the DSM cost impacts. The avoided generation costs from the system tools and the avoided Transmission and Distribution ("T&D") revenue requirements as estimated by PRICEM will be used to calculate the benefits of the RIM, TRC and Program Administrator test for each DSM change case.*

The projected deadline for including new programs in the system planning process is mid 2012.

The Company has satisfied the requirements outlined in the Nine Step process. Particularly noteworthy are the requirements of Steps 2 and 3. The Company filed with the Commission a new energy efficiency potential study on January 31, 2012 (as required by Step 2) along with an update filed on December 4, 2012. The Company also completed the update of the Technology Catalog by January 1, 2012 (as required by Step 3) and shared the information with the Commission Staff and members of the DSMWG on December 29, 2011, along with an update on January 4, 2013.

Additionally, the Company met with Commission Staff throughout the two year (2011-2012) planning phase of the 2013 IRP to provide updated progress toward completing the Nine Step process.

5.1.5 2013 IRP Avoided Cost/Fuel Price Decreases

Future estimated costs for fuel continue to be dynamic and, therefore, the avoided costs related to future resources are dynamic. The avoided fuel cost savings from customers installing DSM measures in the 2013 IRP have declined from the 2010 IRP. These changes in avoided cost savings have a significant negative impact on the economics of the Company's current and proposed DSM programs. As is discussed later in this section, Total Resource Cost ("TRC") Test results declined and Ratepayer Impact Measure ("RIM") Test results worsened as well, causing concerns for the Company in its efforts to balance the economic benefits these programs have for participating customers with the rate impacts caused by the programs.

5.2 DISCUSSION OF CURRENT AND PROPOSED DSM PROGRAMS

5.2.1 Continuation and Expansion of Current Certified DSM Programs and Addition of New Certified DSM Program

5.2.1.1 Residential DSM Programs

In its 2013 DSM Application, the Company is requesting the following actions or adjustments for the following certified residential DSM programs:

Residential Programs

- EarthCents New Home program (formerly known as High Efficiency New Home program) - Amend the New Home certificate as a result of the expansion of the program.
- EarthCents Home Energy Improvement program (formerly known as Residential Existing Homes program) - Approve updated program economics.
- EarthCents Residential Lighting and Appliance program - Amend the certificate to split the program into two individual programs:
 - EarthCents Appliance program
 - EarthCents Lighting program
- EarthCents Refrigerator/Freezer Recycling program - Approve updated program economics.
- EarthCents Power Credit program – No changes requested.
- EarthCents Residential Water Heating program - Decertify and combine goals with the EarthCents Home Energy Improvement program.

EarthCents New Home Program. This program focuses on a whole-house approach to improving the energy efficiency of new homes, promoting the installation of energy efficient measures in new home construction, and improving the performance of participating homes to at least 15 percent above the current Georgia State Energy Code at the time the home is built. Additionally, it will promote improvements in individual measures such as high efficiency electric heating and cooling equipment and heat pump water heaters.

Details of the program continuation are outlined in the ten-year Program Plan found in the 2013 DSM Application.

The 2014 expected energy reductions and cost-effectiveness of the EarthCents Residential New Home Program are as follows:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Test	Participants Test	Societal Test
EarthCents Residential New Home	685	5,186,430	\$ (4,444,597)	\$ 1,958,491	\$ 3,005,808	\$ 6,403,089	\$ 2,129,618

Note: Economic test results are the NPV over the life of the measure.

EarthCents Home Energy Improvement Program. This program promotes a comprehensive, whole-house approach to improving the energy efficiency and comfort of existing homes. It also offers an alternate path that allows customers to make improvements to individual areas of the thermal envelope and equipment in their homes as well. The features of the former Residential Water Heating Program which were also being marketed through this program for years 2011 – 2013 will be included in this program.

Details of the program continuation are outlined in the ten-year Program Plan found in the 2013 DSM Application.

The 2014 expected energy reductions and cost effectiveness of the EarthCents Residential Home Energy Improvement Program are as follows:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Test	Participants Test	Societal Test
EarthCents Residential Home Energy Improvement	6,054	10,918,075	\$ (10,746,370)	\$ 5,246,089	\$ 4,173,049	\$ 15,992,459	\$ 5,589,247

Note: Economic test results are the NPV over the life of the measure.

EarthCents Lighting Program. This program promotes the purchase and installation of energy efficient lighting and lighting fixtures through customer education, retailer partnerships/training, promotional giveaways of high efficiency lights, and customer incentives.

Details of the program continuation are outlined in the ten-year Program Plan found in the 2013 DSM Application.

The 2014 expected energy reductions and cost effectiveness of the EarthCents Residential Lighting Program are as follows:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Test	Participants Test	Societal Test
EarthCents Residential Lighting	1,325	13,918,542	\$ (5,377,548)	\$ 2,958,287	\$ 3,720,942	\$ 8,335,835	\$ 3,110,253

Note: Economic test results are the NPV over the life of the measure.

EarthCents Appliance Program. This program promotes the purchase and installation of energy efficient appliances through customer education, retailer partnerships/training, and customer incentives.

Details of the program continuation are outlined in the ten-year Program Plan found in the 2013 DSM Application.

The 2014 expected energy reductions and cost effectiveness of the EarthCents Residential Appliance Program are as follows:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Test	Participants Test	Societal Test
EarthCents Residential Appliance	399	8,043,589	\$ (5,036,188)	\$ 5,389,529	\$ 3,043,625	\$ 10,425,716	\$ 5,542,454

Note: Economic test results are the NPV over the life of the measure.

EarthCents Refrigerator/Freezer Recycling Program. This program aims to eliminate inefficient or extraneous refrigerators and freezers in an environmentally safe manner and produce cost-effective long-term energy and peak demand savings. The program focuses on increasing residential customer awareness of the economic and environmental costs associated with running inefficient, older refrigerators and freezers. The program provides cash incentives, free pickup, and recycling for qualifying equipment.

Details of the program continuation are outlined in the ten-year Program Plan found in the 2013 DSM Application.

The 2014 expected energy reductions and cost effectiveness of the EarthCents Refrigerator/Freezer Recycling Program are as follows:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Test	Participants Test	Societal Test
EarthCents Refrig/Freezer Recycling	827	17,519,548	\$ (10,367,781)	\$ 4,251,958	\$ 3,672,626	\$ 14,619,739	\$ 4,482,280

Note: Economic test results are the NPV over the life of the measure.

EarthCents Power Credit Program. The Power Credit program is a residential load control program that currently has approximately 53,000 participants. Some of the participating homes have more than one direct load control unit switch to control multiple Heating, Ventilation and Air Conditioning (“HVAC”) units. The Power Credit program allows Georgia Power to cycle HVAC systems during periods of high system capacity constraints and high energy costs. HVAC energy is thereby shifted into off-peak periods that typically have lower demands and energy costs. The program provides approximately 100 MW of demand reduction.

Georgia Power is currently replacing the low frequency radio receiver load control technology with 900 MHz receivers. This replacement should be completed by the end of 2013.

EarthCents Residential Water Heating Program. This program will be decertified and further activity will be included within the EarthCents Home Energy Improvement Program.

5.2.1.2 Commercial DSM Programs

In its 2013 DSM Application, the Company is also requesting the following actions or adjustments for the following certified commercial DSM programs:

Commercial Programs

- EarthCents Commercial Prescriptive Incentive program – Approve updated program economics.
- EarthCents Commercial Custom Incentive program – Amend the certificate.
- EarthCents Small Business program – Grant a new certificate.

The prescriptive and custom commercial programs will be marketed and advertised as one program to commercial customers for ease of implementation and to avoid market confusion. They will be marketed as the EarthCents Commercial Energy Efficiency Program to new and existing customers but will continue to have separate budgets, energy savings targets, and economic analyses.

EarthCents Commercial Prescriptive Incentive Program. This program promotes the purchase of eligible high-efficiency equipment installed at qualifying customer facilities.

Customer incentives will be offered through this program to reduce the incremental cost to upgrade to high-efficiency equipment and measures over standard efficiency options.

Details of the program continuation are outlined in the ten-year Program Plan found in the 2013 DSM Application.

The 2014 expected energy reductions and cost effectiveness of the EarthCents Commercial Prescriptive Incentive Program are as follows:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Test	Participants Test	Societal Test
EarthCents Commercial Prescriptive	8,259	26,865,348	\$ (6,395,600)	\$ 10,759,642	\$ 17,277,218	\$ 17,155,243	\$ 11,319,134

Note: Economic test results are the NPV over the life of the measure.

EarthCents Commercial Custom Incentive Program. This program provides a platform for comprehensive energy efficiency projects in larger facilities that go beyond single measures and common efficiency practices. The program does not define a specific list of eligible measures but bases participation and customer incentives on the verifiable energy savings resulting from the measures implemented. Measurement and verification procedures will vary depending on the energy efficient products installed.

Details of the program continuation are outlined in the ten-year Program Plan found in the 2013 DSM Application.

The 2014 expected energy reductions and cost effectiveness of the EarthCents Commercial Custom Incentive Program are as follows:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Test	Participants Test	Societal Test
EarthCents Commercial Custom	44,520	205,476,528	\$ (27,775,186)	\$ 133,099,669	\$ 210,752,047	\$ 160,874,855	\$ 139,578,031

Note: Economic test results are the NPV over the life of the measure.

EarthCents Small Business Program. This program promotes the purchase of eligible high-efficiency equipment for small commercial businesses that are either more similar in

construction to residential buildings or just of a smaller nature. Customer incentives offered through this program serve to reduce the incremental cost to upgrade to high-efficiency equipment or measures over standard efficiency options. Some of the measures in the program were modeled after the EarthCents Home Energy Improvement program. The remaining measures included are from the other two commercial programs with different rebate levels for the smaller commercial customers. Customers who are eligible for the Small Business program will also be eligible to participate in the Commercial Custom Incentive and Commercial Prescriptive Incentive programs.

Details of the program are outlined in the ten-year Program Plan found in the 2013 DSM Application.

The 2014 expected energy reductions and cost effectiveness of the EarthCents Small Business Program are as follows:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Test	Participants Test	Societal Test
EarthCents Small Business	2,569	8,647,047	\$ (4,760,290)	\$ 6,347,198	\$ 9,547,237	\$ 11,107,489	\$ 6,646,531

Note: Economic test results are the NPV over the life of the measure.

Each of the ten-year DSM Program Plans allows for ongoing review and modification of program design features through regular program monitoring as well as the formal program evaluation plan in an effort to maximize energy savings while maintaining economic efficiency. Any significant changes to program design in support of market conditions or program economics will be included with ongoing reports filed with the Commission, program evaluation filings, and/or IRP updates as needed. Additionally, as new measures and technologies evolve during the 10 year filed program life, the Company may add them to these programs. Any new measures being added would have to follow the same economic screening process as those approved by the Commission and the Commission would be made aware of any additions prior to the Company offering the new measures to customers.

5.2.2 Continuation of the Weatherization Assistance for Low Income Customers Program

The Weatherization Assistance for Low Income Customers program began in January 1996. The program was designed to provide monetary assistance to Resource Services Ministries (“RSM”) and the Georgia Environmental Finance Authority (“GEFA”) to augment their existing weatherization assistance efforts for low income customers.

The program currently provides annual funding of \$1.75 million to GEFA and \$250,000 to RSM. Georgia Power plans to continue the funding of the Weatherization Assistance for Low Income Customers program at its current annual funding level of \$2 million through December 31, 2016.

5.2.3 Energy Efficiency Information Programs

Energy efficiency informational brochures, websites and events developed by Georgia Power assist customers in learning about using energy more efficiently. Specific program information costs are handled in the applicable program budgets and are included in that particular program’s implementation. General energy efficiency awareness efforts using many different media (TV, radio, websites, and print ads) help customers understand the general benefits of using energy efficiently and directs them to specific programs.

Georgia Power has increased its focus on using online information tools and social media, such as Twitter and Facebook, to engage interested parties in energy efficiency discussions.

5.2.4 Energy Audits, Energy Efficiency Information Line and One-On-One Energy Efficiency Assistance

The Company also provides a number of other avenues for one-on-one customized assistance to customers to help them better understand their energy usage and to identify energy efficiency opportunities. Additionally, in-home (more than 8,000 in 2012), in-facility (more than 1,500 in 2012) and on-line (more than 86,000 in 2012) energy audits are offered to customers to assist in identifying energy and money savings opportunities, and also serve as marketing channels to direct customers to participate in energy efficiency programs. Furthermore, over 40,000 calls a year are received through the Company’s energy efficiency hotline from residential customers seeking energy efficiency advice. One-on-one assistance is also offered and is typically directed

toward helping the Company's larger commercial and industrial customers through its key account managers; however, assistance can be provided to any customer by virtually any employee in the Company.

5.2.5 Energy Efficiency Awareness Initiative

Georgia Power's Energy Efficiency Awareness initiative promotes the benefits of energy efficiency and educates customers about specific ways to save money and energy. The Commission-approved budget for this activity is \$4.4 million annually for years 2011 through 2013. This budget has historically supported awareness in the residential market. Going forward there is a need to also raise awareness in the commercial markets. Georgia Power requests an increase in this annual budget to \$5.4 million for years 2014 through 2016. This increase request keeps the residential campaign at \$4.4 million annually and adds \$1 million annually for commercial general awareness.

Georgia Power uses direct marketing channels to efficiently reach its customer base. Television, radio, print, internet, billboard, and local office advertising and direct mail are the primary channels used. The Company has developed a number of online tools and has placed them on its website to enhance customers' learning about energy efficiency. Customers are invited to visit georgiapower.com to learn ways to save energy through general energy efficiency information, helpful tips and specific information about energy efficiency programs offered by Georgia Power. In 2012, more than 466,000 visitors accessed the Company's energy efficiency information website and there were more than 86,000 on-line audits. Social media is also used to communicate with online customers, including Facebook, Twitter and YouTube.

Additionally, Georgia Power has re-initiated its classroom presence through the Learning Power program. Currently, curriculums to support energy and energy efficiency understanding from a grass roots perspective have been developed or are under development for grades K-12. For calendar year 2012, Education Coordinators completed more than 2,700 Learning Power events for more than 70,000 students.

5.2.6 Demand Response Tariffs

For many years, Georgia Power has offered its customers a menu of demand response tariffs, such as:

- **Real Time Pricing** offers customers marginal pricing for incremental load – as prices increase, customers can respond by reducing their demand;
- **Demand Plus Energy Credit** is an interruptible service tariff that provides customers with a demand credit for the potential demand reduction plus provides an energy credit when DPEC is called; and
- **Time of Use** tariffs provide customers with pricing signals during different periods of the day that closely reflect the marginal cost of the energy in the specific time period (peak and off-peak) and encourage customers to modify their usage accordingly.

5.3 DSM RESOURCE ASSESSMENT AND INITIAL COST EFFECTIVENESS SCREENING

5.3.1 Assessment and Screening Methodology

The assessment and screening methodology for DSM measures used in this IRP included identifying DSM programs and measures with detailed input from the DSMWG. Additionally, economic evaluations were performed for each program that was passed to economic screening to determine the program cost-effectiveness based on the industry-standard benefit/cost tests and as required by the Commission IRP rules. The tests conducted are the RIM, TRC, Participants Test (“PT”), Program Administrator Cost Test (“PACT”), and Societal Cost Test (“SCT”). RIM assesses fairness and equity by measuring what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. The TRC test assesses economic efficiency and societal impact by measuring the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants’ and the utility’s costs. The PT assesses the impact on a program participant by measuring the quantifiable benefits and costs to the customer due to participation in a program. The PACT assesses the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net

costs incurred by the participant. The SCT is a variant of the TRC test and includes an adder to avoided fuel costs to simulate environmental externalities.

The Company met with, discussed, and shared presentations related to DSM program design details with the DSMWG at multiple meetings in 2011 and 2012. A smaller sub-group of the DSMWG met and identified the program concepts and measures considered for economic screening in support of the 2013 IRP development. Input from the sub-group participants was used in developing the list of programs to analyze. This list was shared with the larger DSMWG requesting feedback or any additional input to this process. Consensus on programs to include in the analysis was reached with the DSMWG. The preliminary results of the program economic screening were also shared with the DSMWG in advance of this filing.

5.3.2 DSM Program Economic Screening Policy

The Company continues to follow the Commission's economic screening policy outlined in the 2004 IRP Final Order, Docket No. 17687, which requires the Company to offer a DSM plan that minimizes upward pressure on rates and maximizes economic efficiency. Additionally, the Company's DSM plan treats DSM as a priority resource. In fact, the first step in the Company's IRP process is to reduce the Company's energy and demand forecast by the recommended proposed case DSM plan ("Proposed Case") energy and demand impacts prior to developing the supply-side alternatives. The recommended Proposed Case cost-effectiveness results presented herein are representative of modifications to current DSM programs for which the Company seeks continued and amended certification in Docket No. 36499. However, due to the decline in avoided costs since the 2010 IRP, these rate impacts will be larger than the DSM programs approved in the 2010 IRP. At the same time, while the DSM programs provide TRC benefits, such benefits are not as large as in the 2010 IRP due to the decline in avoided costs. The recommended Proposed Case DSM programs will average almost \$187 million (NPV over the life of the measures) in TRC benefits annually but will, on average, put \$82 million of upward pressure on rates (NPV over the life of the measures) annually for years 2014 - 2016.

The aggressive sensitivity case ("Aggressive Sensitivity Case") cost-effectiveness results are also presented herein, as outlined in the Nine Step process. The Aggressive Sensitivity Case is not recommended by Georgia Power and is not a DSM plan that should be approved by this

Commission due to the significant increase in customers' bills and poor economic efficiency, relative to the upward pressure that would result. The Aggressive Sensitivity Case sensitivity includes programs from the recommended Proposed Case but with customer participation at higher penetration levels and associated higher budgets, as well as additional programs, measures, and associated budgets to help reach almost 12.5 percent cumulative energy savings over ten years based on the Budget 2012 forecast.

At the request of some members of the DSMWG, the Company agreed to analyze another case, identified as the DSMWG Advocacy sensitivity case (or "Advocacy Sensitivity Case"), which achieved a 9.5 percent cumulative energy savings over ten years when compared to the Budget 2012 forecast. The results of this sensitivity case were shared with a sub-committee of the DSMWG advocates in August 2012 and with the entire DSMWG in September 2012.

The higher levels of market penetration in both the Advocacy and Aggressive Sensitivity Cases ultimately result in average annual rate impacts of approximately \$461 million and \$650 million (NPV over the life of the measures), respectively, for years 2014 - 2016 over the alternative supply-side resource plan. These plans, if implemented as analyzed, would increase customers' rates approximately six to eight times more than the Company's recommended Proposed Case, while only increasing the economic efficiency (or TRC benefits) by about two and a half to three and a half times, respectively, for the same timeframe.

5.3.3 Data Development

In developing its list of DSM measures for inclusion in programs for initial screening, the Company conducted a comprehensive review of technical information sources for demand-side and energy-efficiency technologies. This review included evaluation of the Company's previous IRP filings, as well as reviews of new sources of information. Additional input was provided by the DSMWG members. Company representatives who work closely with Georgia Power's customers were also surveyed for their input. Additionally, customer feedback from surveys was reviewed as a source of information for program additions and improvements. Information gathered was shared with the DSMWG in the program development discussions. A compilation of the qualitative screening of DSM measures is included in Technical Appendix 2.

5.3.3.1 Residential Technology

More than 100 residential DSM measures within nine programs were identified for program economic screening. These measures provided potential energy savings through:

- customer behavior improvements;
- compliance with state standards and codes;
- increased energy efficiency for electric appliances;
- electric space cooling and heating equipment;
- electric lighting;
- electric water heating; and
- heating and cooling savings resulting from improvements to the home's thermal shell and increased equipment efficiency.

In addition to specific measures, the building type (new and existing single family, multifamily, or manufactured housing, where applicable) was considered in the economic analysis.

5.3.3.2 Commercial Technology

More than 150 commercial DSM measures within five programs were identified for program economic screening. These measures provide energy savings through:

- compliance with state standards and codes;
- increased energy efficiency for electric equipment;
- electric space cooling and heating equipment;
- electric lighting;
- electric water heating; and
- heating and cooling savings resulting from improvements to the building's thermal shell.

In addition to specific measures, the building type (the type of customer operation, such as schools and offices, where applicable) was considered along with the construction type (new, existing or both, where applicable) when conducting the economic analysis.

5.3.3.3 Industrial Technology

A total of six custom industrial DSM measure categories within one custom program were identified for economic screening in the Advocacy and Aggressive Sensitivity Cases. No industrial programs are included in the Company's recommended Proposed Case. These measures provide energy savings through:

- electric space cooling and heating equipment;
- electric lighting;
- motors;
- compressed air;
- industrial process equipment; and
- retro-commissioning.

5.3.4 Economic Screening

Energy consumption and savings were calculated for all programs that were passed to the economic screening. Two main methods were used to calculate the energy consumption and savings potential for each measure.

The energy usage characteristics for weather-sensitive HVAC and thermal shell measures were calculated using an engineering simulation model ("EnerSim"). EnerSim is an hourly building energy simulation model used to predict energy consumption in buildings based on construction characteristics, insulation, occupancy, orientation, local weather, etc. EnerSim was used to generate all energy usage profiles for weather-sensitive end-uses examined in both residential and non-residential measures. EnerSim has been certified and approved by the U.S. Department of Energy ("DOE") and is listed on their website as "Qualified Software." Energy usage for non-weather-sensitive end-uses was calculated using the EnerSim program, from secondary sources listed above, or from other end-use specific calculations.

Each potential end-use measure that was passed to the economic screening was then evaluated in an economic analysis model to determine its benefits and costs. The Company used PRICEM, which is an economic analysis tool maintained by SCS, for a portion of this analysis. PRICEM

produces estimates of the avoided utility costs and lost revenues over the useful life of the end-use equipment. Utility avoided costs include estimates of the supply-side capacity and energy costs that can be avoided by each measure and savings from generation, transmission, distribution, fuel, environmental, and other costs.

The following industry-standard DSM cost-effectiveness tests were calculated for each measure (and subsequent programs): the PT, the RIM test, the TRC test, the PACT, and the SCT. Additionally, the Cost of Saved Energy (“CSE”), also referred to as Levelized Cost per annual kWh saved, is provided for each of the programs. The CSE is the total cost per kWh of realizing the efficiency improvement. CSE is determined by dividing levelized program costs by the annual energy savings, as shown in the following equation. Levelized program costs are calculated using a Capital Recovery Factor (“CRF”), which incorporates the number of years that the energy savings persist, and an annual discount rate.

$$\begin{aligned} & \text{CSE Equation.} \\ \text{CSE} &= \frac{\text{Program Costs (\$)} \times \text{CRF}}{\text{Annual Energy Savings (kWh)}} \end{aligned}$$

A compilation of the economic screening of DSM measures that passed the qualitative screening is included in Technical Appendix 2.

5.4 DEMAND-SIDE PROGRAM DEVELOPMENT

5.4.1 Demand-Side Resource Policy

In the 2004 IRP, the Commission directed that proposed DSM plans should minimize upward pressure on rates (negative RIM results) and maximize economic efficiency (positive TRC results). Additionally, the Commission directed that the cost/benefit analysis results of each initiative should use all three tests (PT, RIM and TRC test) and should balance economic efficiency (TRC benefits) and fairness and equity (RIM benefits/cost). This Commission policy was affirmed in the 2007 and 2010 IRPs. The Company utilized this same philosophy in analyzing the programs for the 2013 IRP.

This IRP adheres with the Nine-Step process for developing the 2013 IRP approved by the Commission in July 2010 as part of the 2010 IRP Final Order.

5.4.2 10-Year DSM Program Plans

The Company has developed ten-year program plans outlining the implementation details behind each individual program included in the recommended Proposed Case. Each of the energy efficiency program plans are provided in the 2013 DSM Application.

Included in each program plan are the following details:

- *Program Summary* – outlines the goals of the program and presents a logic model to graphically represent the relationships between activities and outcomes for the individual programs.
- *Program Structure* – outlines participant eligibility, home or facility eligibility, and specific measures and incentives where appropriate.
- *Program Implementation* – outlines the target market, key market players, as well as marketing and outreach plans.
- *Program Operation* – outlines the customer participation process and program administrative procedures.
- *Program Evaluation* – outlines the performance metrics, expected program budget, cost-effectiveness expectations, as well as plans to develop an independent third-party evaluation plan after programs are approved.

5.5 REGULATORY TREATMENT OF DSM PROGRAM COSTS AND THE ADDITIONAL SUM

Georgia Power is requesting the continued collection of costs for all approved and certified DSM programs and activities through the existing Residential and Commercial DSM tariffs. Georgia Power is also requesting the continued collection of the Additional Sum approved by the Commission for certified DSM programs through these tariffs. These tariffs will be filed as part of the Company's 2013 base rate case and would be implemented with any approved change of rates on January 1, 2014.

5.6 SUMMARY OF DSM CASES

5.6.1 Proposed Case – Georgia Power Recommended Case

The energy efficiency programs in Georgia Power's recommended Proposed Case for the 2013 IRP achieve an average of almost \$187 million (NPV over the life of the measures) in TRC benefits while putting upward pressure on rates of almost \$82 million (NPV over the life of the measures) annually over years 2014 - 2016. The Company is concerned that these results are not striking the balance needed when considering energy efficiency programs, but recommends continuing the energy efficiency programs approved in the 2010 DSM Certification filing at the projected increased market participation levels. The Company's recommendation to continue the programs at this time is based on the desire to minimize market disruption, to continue meeting customers' expectations, and to maintain positive relationships with vendors performing qualified program improvements. The Company is also seeking to certify a Small Business program targeted toward a hard to reach customer sector. The Company plans to monitor program costs and economics during 2014 - 2016 and will be prepared to modify or discontinue programs if significant upward pressure on rates continues.

The Company's DSM portfolio included in the 2013 IRP consists of currently certified programs, modified based on data gathered in the implementation phase and input from the DSMWG and the independent third party evaluation. The portfolio also includes a new Small Business program. If the Proposed Case is approved, Georgia Power will continue to enhance these programs as more information becomes available relative to market penetration and customer feedback through an ongoing evaluation process. Georgia Power will keep the Commission fully informed of potential changes to program design.

The Company's Proposed Case summary economics are provided in the DSM Program Documentation section of Technical Appendix Volume 2. As part of the Nine-Step process, the Company agreed to calculate the generation avoided costs for its DSM change case using its system tool. The avoided generation costs for the Company's proposed case from the system tool were not significantly different than the avoided generation costs obtained from PRICEM. Also, the avoided generation costs for the Advocacy and Aggressive Sensitivity Cases from the

system tool were not significantly different than the avoided generation costs obtained from PRICEM.

5.6.2 DSMWG Advocacy Sensitivity Case – All Program Concepts Identified with DSMWG Subgroup

The DSMWG Advocacy Sensitivity Case was developed as a sensitivity case to the Company's recommended DSM plan and is based on requests made by certain members of the DSMWG. Georgia Power presents the results of this case for informational purposes. Georgia Power does not recommend approval of the DSMWG Advocacy Sensitivity Case.

If the DSMWG Advocacy Sensitivity Case is implemented, the portfolio would put additional upward pressure on rates of approximately \$461 million (NPV over the life of the measures) on average annually for years 2014 - 2016, almost six times higher than the Company's recommended Proposed Case, while only increasing the economic efficiency (or TRC benefits) by about two and a half times. Over the life of all programs within this sensitivity case, rates would increase on average by about \$613 million annually (NPV over the life of the measures) relative to the supply-side option.

The DSMWG Advocacy Sensitivity Case summary economics are provided in the DSM Program Documentation section of Technical Appendix Volume 2.

5.6.3 Aggressive Sensitivity Case

The Aggressive Sensitivity Case was developed to represent an aggressive DSM sensitivity and was developed with input from the DSMWG, as outlined in the Nine-Step process. Georgia Power does not recommend approval of the Aggressive Sensitivity Case.

The Aggressive Sensitivity Case serves as a reference point to estimate the maximum achievable potential for increased energy efficiency and the impacts of such aggressive adoption of DSM. This increased energy efficiency comes at high cost to customers. The higher impacts from the Aggressive Sensitivity Case ultimately result in an average annual rate impact of more than \$650 million (NPV over the life of the measures) over the alternative supply-side resource plan for years 2014 - 2016, about eight times higher than the Company's recommended Proposed Case,

while only increasing the economic efficiency (or TRC benefits) by about three and half times. Over the life of all programs within this sensitivity case, rates would increase on average by almost \$861 million annually (NPV over the life of the measures) relative to the supply-side option.

The Aggressive Sensitivity Case summary economics are provided in the DSM Program Documentation section of Technical Appendix Volume 2.

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6 – SUPPLY-SIDE PLAN

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SECTION 6 - SUPPLY-SIDE PLAN

6.1 OVERVIEW

The supply-side benchmark planning process consists of the following steps:

- Assessing options at existing generation facilities;
- Evaluating power purchases;
- Assessing current and new electric generation technologies that may be available when new capacity is needed;
- Selecting the least-cost mix of capacity to develop the plan and the benchmark plan; and
- Evaluating the benchmark plan across a range of changing assumptions to assess risk, flexibility, and other considerations.

The benchmark plan is used throughout the IRP process, and cost-effective demand-side options are integrated with the benchmark plan to create the IRP. The IRP is the basis for evaluations of resource options until the next plan is completed.

6.2 EXISTING GENERATING PLANT OPTIONS

The 2013 IRP contains a supply-side plan that reflects the Company's decisions for transitioning its generation fleet to best meet the requirements of existing and potential environmental rules and regulations, most significantly, the final MATS rule. Encompassing previous actions and decisions resulting from the IRP planning process overseen by the Commission, as well as the Company's requested actions in this 2013 IRP filing, the supply-side plan reflects an efficient and diverse fleet of resources. Further detail regarding existing and committed units is located in the Resource Ledger in Technical Appendix Volume 1.

6.2.1 Previous Resource Commitments

The supply-side plan reflects previous decisions and actions resulting from the IRP planning process, including the retirements of Plant McDonough-Atkinson Units 1 and 2, Plant Mitchell Unit 4C, and Plant Branch Units 1 and 2. The plan also includes the addition of resources, most notably the two new nuclear units at Plant Vogtle Units 3 and 4, the three new CC units at Plant

McDonough-Atkinson Units 4-6, capacity planned and procured for the Company's Large Scale Solar program and the GPASI, and the purchase of 998 MW of natural gas fired capacity and energy from West Georgia, Dahlberg and Harris and associative Proxy Qualifying Facilities' ("QFs") capacity resulting from the 2015 RFP.

6.2.2 Installation of Environmental Controls for Plant Bowen Units 1-4, Plant Wansley Units 1 and 2, Plant Scherer Units 1-3 and Plant Hammond Units 1-4 to Allow for Continued Operation

An important aspect of the supply-side plan is the continued operation of coal-fired generation through the application of further environmental controls, most notably those required for MATS compliance. As described above and as detailed in Sections 1.6.1, 1.6.4, 1.6.8, and 1.6.9 in the Unit Retirement Study and in the Environmental Compliance Strategy contained in Technical Appendix Volume 2, the Company has developed a MATS compliance strategy for Plant Bowen Units 1-4, Plant Wansley Units 1 and 2, Plant Scherer Units 1-3, and Plant Hammond Units 1-4. The Company's analysis of continued operations of these resources results in a net benefit to customers and will result in these valuable assets continuing to economically serve customers' needs, while maintaining a significant role for coal in the Company's generation fleet.

6.2.3 Switching Primary Fuels at Plant Mitchell Unit 3, Plant Yates Units 6 and 7, Plant McIntosh Unit 1, and Plant Gaston Units 1-4 to Allow for Continued Operation

The supply-side plan also includes continued operations at Plant Mitchell Unit 3, Plant Yates Units 6 and 7, Plant McIntosh Unit 1, and Plant Gaston Units 1-4. As discussed above, the MATS compliance strategies for these plants are different than for Plants Bowen, Wansley, Scherer and Hammond. While Plants Bowen, Wansley, Scherer, and Hammond will achieve MATS compliance through varying applications of baghouses, and MATS additives, the compliance strategies for the units discussed below rely heavily upon leveraging opportunities presented by switching primary fuels.

Plant Mitchell Unit 3 reflects the conversion to a biomass generating unit previously approved by the Commission to allow for continued future operation. The Company provided updates on the conversion project through the Commission's construction monitoring process and continues to evaluate the economics of the conversion; therefore, the unit is assumed to be unavailable in

2015 and 2016 and then available as a biomass generating unit in 2017 and beyond in this 2013 IRP. For further details regarding Plant Mitchell Unit 3, please see Section 10.5.2.

Plant Yates Units 6 and 7 will continue to operate by switching to natural gas as the primary fuel, as MATS is not applicable to natural gas-fired units. Details regarding the assumptions for the compliance strategy are contained in Section 1.6.11 in the Unit Retirement Study contained in Technical Appendix Volume 2.

Plant McIntosh Unit 1 will continue operations by completing a fuel switch to PRB coal (pending a successful test burn and subsequent feasibility study in 2013) and the installation of activated carbon and dry sorbent injection technologies by an assumed date of April 2016. Assuming the project is completed after the MATS compliance date of April 15, 2015, a one year MATS extension would be requested from the EPD to ensure the unit can operate until the switch to PRB coal is complete. Details regarding the assumptions for the compliance strategy are contained in Section 1.6.6 in the Unit Retirement Study and in the Environmental Compliance Strategy contained in Technical Appendix Volume 2.

Similar to Plant Yates 6 and 7, Plant Gaston Units 1-4 will continue operations by switching to natural gas as the primary fuel. Details regarding the assumptions for the compliance strategy are contained in Section 1.6.3 in the Unit Retirement Study contained in Technical Appendix Volume 2. Completion of the gas lateral and unit modifications for Plant Gaston Units 1-4 is scheduled for 2015 to meet the MATS compliance timeline; however, the project schedule is compressed. An extension to the MATS compliance date may be required to ensure the units operate in compliance while on coal if the current project schedule cannot be met.

6.2.4 Decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6

The supply-side plan reflects the retirements of Plant Branch Units 3 and 4, Plant Yates Units 1-5, and Plant McManus Units 1 and 2 effective with the MATS compliance date. It also reflects the retirement of Plant Kraft Units 1-4 one year past the MATS compliance date to allow for necessary area transmission upgrades, the retirement of Plant Boulevard Units 2 and 3 effective

as of the date of the final order in this proceeding, and the retirement of Plant Bowen Unit 6 by April 16, 2013.

Details regarding the assumptions for the compliance strategies required for Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, and Plant Yates Units 1-5 are contained in Sections 1.6.2, 1.6.5, 1.6.7, and 1.6.10 in the Unit Retirement Study contained in Technical Appendix Volume 2. The results of the analyses show that it is not economic for customers for the Company to invest in these units to allow for continued operations.

Plant Boulevard Units 2 and 3 are two oil-fired CTs that have recently experienced significant equipment failures that would be costly to repair. Following a failure of the two units in July and November, respectively, a camera probe of the units was performed to determine what parts would need to be repaired or replaced. Through this effort, it was revealed that the compressor rotor blades were damaged on Unit 2 and the repair was estimated to cost \$1.95 million. For Unit 3, a camera probe also revealed damage to the compressor on that unit and a repair was estimated at \$1.75 million. In Section 1.6.12 in the Unit Retirement Study contained in Technical Appendix Volume 2, the estimated cost of repairs for Plant Boulevard Units 2 and 3, as well as the annual maintenance capital and O&M budgets for the units, were included as the costs of the unit. Based on the cost of repair, the age of the units, and the potential for additional part failure, it is not considered economic to repair and continue operating these units.

Plant Bowen Unit 6 is a 32 MW oil-fired CT that can only operate during the non-summer months due to ozone nonattainment requirements in the area. The economics of the unit were evaluated and are included in Section 1.6.13 in the Unit Retirement Study contained in Technical Appendix Volume 2. Based on this evaluation, it is uneconomic to continue operating this unit. Several options were explored for the unit, however, to help facilitate baghouse construction occurring at Plant Bowen Units 3 and 4, and the Company determined that it is most optimal for this unit to be removed no later than June 1, 2013.

Additionally, early decertification is being sought for this unit in order to take advantage of an agreement in place to sell the unit. In order to allow the buyer sufficient time to remove the unit before June 1, 2013, decertification would need to be granted by April 16, 2013.

6.2.5 Blackstart Resources and Transmission System Restoration Plan

For transmission reliability purposes, certain generating units are designated as “Blackstart Resources”. Blackstart Resources are defined, per NERC reliability standards, as “a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan”. A review and assessment of Blackstart Resources and the Company’s Transmission Operator system restoration plan continues in conjunction with unit retirement studies. System restoration plans will continue to be updated annually at a minimum or as required due to changes in the future mix of generating assets.

6.3 SUPPLY-SIDE OPTIONS

Based on current projections and reflecting reserve sharing for the System, the Company is projected to have adequate capacity reserves through 2022 and, thus, there is no plan in this IRP to add capacity within the next three years. As discussed in Section 6.2, the Company has developed plans for the retrofitting and transitioning of its generation fleet to best meet the requirements of existing and potential environmental rules and regulations including, most significantly, the final MATS rule.

6.4 NEW GENERATING TECHNOLOGIES

The System continually evaluates conventional and emerging generating technologies as a starting point in developing a base supply-side plan. The objective is to assess their cost, status of development, cost uncertainties, environmental acceptability, fuel availability, construction lead times, and other factors.

The evaluation process:

- Identifies and reviews all conventional and new supply-side generation technologies;

- Performs a preliminary technology screening analysis based on technical, economic, environmental, and resource availability information;
- Performs a more detailed technology screening analysis of the options that passed the preliminary screening, which includes a busbar economic comparison of the candidate technologies;
- Projects the future cost and performance of the selected supply-side alternatives; and
- Identifies the technologies to be recommended for inclusion in the resource mix studies.

6.4.1 Preliminary Screening

The 2013 technology screening process identified 39 technologies for strategic assessment. They are listed in Section 14, Attachment 14.2 and Table 14.2.1. The strategic or qualitative assessment considered the stage of development of the technology, fuel availability, environmental impact, financial requirements, cost uncertainties, construction lead-time, and operating characteristics.

Many technologies from the initial list did not pass the preliminary screening due to their limited applicability to the territory (e.g., Ocean Thermal Generation) or their early stage of development (e.g., magnetohydrodynamics). Twenty-two technologies were carried forward for more detailed analysis (refer to Section 14, Attachment 14.2 and Table 14.2.3). See Section 10 for discussion regarding renewable generation options.

6.4.2 Detailed Screening

In order to pass through the second screening, a supply-side option must have desirable economic characteristics, as well as desirable environmental and other non-price characteristics.

To be economically attractive, an option must be among the lowest-cost options across a range of capacity factors. A busbar cost screening analysis is the common industry method used to determine the cost of operating a unit over a range of capacity factors. Busbar models combine the capital and operating costs of generating units so that the costs of operating units can be compared under various hours of annual operation. Also, busbar models provide an indication of

the economic viability of one technology compared with others. Busbar models are very useful in screening evaluations for generation technology options.

All data assumptions are shown in Table 6.4.2 in the IRP Main Document Reference Tables section of Technical Appendix Volume 1. A capital cost comparison and busbar curves are shown in Figures 6.4.2.1 and 6.4.2.2, respectively, in the IRP Main Document Reference Tables section of Technical Appendix Volume 1.

Even though a technology may not be the absolute lowest-cost option, it may be a desirable alternative due to qualitative features, such as stage of development, ease of siting, modularity, short construction lead time, flexible operating characteristics, fuel diversity, or anticipated improvements that favorably impact the economics of the technology. These attributes are also considered in the detailed screening.

6.4.3 Nuclear Generation

Nuclear generation is included as a generating unit option in this IRP. The 2013 Generation Technology Data Book, included in Technical Appendix 1, provides the capital cost for pre-licensed nuclear generation.

6.4.4 Generation Mix Candidate Selections

The detailed economic results are used to determine likely candidates as representative capacity options in the base case resource mix studies. The base case technologies recommended include:

- CT, peaking;
- CC – “G”, base load/intermediate;
- CC – “G”, with carbon capture and sequestration (CCS), base load/intermediate;
- Nuclear, base load; and
- Coal with carbon capture and sequestration (CCS), base load.

6.5 SUPPLY-SIDE PLAN

To develop a supply-side plan, the technologies that passed the detailed screening are further evaluated using the PROVIEW™ computer model to arrive at a benchmark plan. The key input

assumptions are generating unit characteristics, fuel costs, reliability needs, financial costs and escalation rates. A summary of the PROVIEW™ model is in Section 14.

6.5.1 Base Case Assumptions

Generating Unit Costs — The types of generating units used in developing the benchmark plan were coal with CCS and nuclear, CC (both with and without CCS) and peaking CT.

Fuel Costs — In the optimization process, the primary fuels used in the candidate units of the optimization are nuclear, coal, oil, and gas. Figure 3.7.1 in the Mix Study in Technical Appendix Volume 1 shows projections of nominal delivered costs of coal, nuclear, oil, and natural gas based on heat content.

Reliability Needs — The supply-side plan is currently developed to meet a System planning target reserve margin of 15 percent. This target was developed using a combination of economic studies, electric industry experience, and operator input. The economic analysis compares emergency purchase cost and customers' value of service [based on EUE cost] with the cost of adding capacity to avoid outages.

Financial Cost and Escalation — Long-term debt and common and preferred stock are issued to finance the construction of generating units. The returns demanded by the investment community are affected by perceptions of the inflation rate and business risks. The returns demanded by the investment community and the income tax rates affect the carrying cost of the investment, which can in turn affect the mix of capacity.

The Moody's Analytics forecast is the basis of the financing and inflation cost estimates used in the planning process. For the mix analysis, an internally-developed average set of costs escalations was used. Discount analysis using the weighted average cost of capital is applied to place more emphasis on the near term. (More information on this topic is available in the Mix Study report in Technical Appendix Volume 1.) The financial parameters used in the mix process are also shown in the Mix Study in Technical Appendix Volume 1.

6.5.2 Benchmark Plan Results

The optimization process utilizes the PROVIEW™ module of the production cost Strategist® model and determines the proper mix of capacity to serve a designated load. The results of this analysis indicate the proposed capacity additions. The capacity additions identified within this analysis serve as a guide for the type of capacity needed in a particular timeframe with the given assumptions. As prescribed by the Commission's rules and orders, a combination of self-owned generation and a competitive bidding process will be used for determining how the capacity needs are to be met.

The optimization process is essentially a trade-off between fixed costs and variable operating costs for the various generating unit options. Figure 6.5.2.1 in the IRP Main Document Reference Tables section of Technical Appendix Volume 1 depicts changes in energy mix by fuel source for the 2013–2032 planning period. As energy usage increases and no new coal-fueled generating units are added, the amount of energy supplied by oil and natural gas will increase. Figure 6.5.2.2 in the IRP Main Document Reference Tables section of Technical Appendix Volume 1 shows the portion of annual energy needs met by nuclear, coal and hydro units over the planning period 2013 - 2032. Table 6.5.2.1 in the same section of Technical Appendix Volume 1 shows the System Benchmark Capacity Plan.

6.5.3 Reference Case Sensitivities

There are four major reasons to test the benchmark plan under different assumptions:

- * To determine how well the plan will meet customer needs under a variety of different future outcomes;
- * To determine if the plan should be altered to make it more flexible in meeting unforeseen changes;
- * To build knowledge and intuition concerning the effect that different assumptions will have on the supply-side plan; and
- * To identify and focus attention on additional studies to be performed.

The following sensitivities were performed in the development of the Company's IRP. These sensitivities are analyzed in detail in the System Mix Study found in Technical Appendix Volume 1.

- Forecast of load:
 - Sensitivity 1 evaluates zero load growth from 2013 levels.
 - Sensitivities 2 and 3 evaluate higher and lower load growth.
- In-service dates of supply and demand resources:
 - Sensitivities 4 and 5 evaluate levels of demand-side options.
 - Sensitivities 12 through 21 evaluate the impacts of varying in-service dates and amounts of supply and demand resources through the scenario planning cases. In addition to separate fuel price forecasts and estimates of carbon prices, sensitivity cases 13 through 21 produce separate evaluations of the impacts on the load and energy forecasts, which include effects from demand-side programs, and new supply-side resources.
- Unit availability:
 - Sensitivities 6 and 7 evaluate lower and higher forced outage rates.
- Fuel prices:
 - Sensitivities 13 through 21 evaluate the impacts of fuel prices through the scenario planning cases which have three separate fuel price forecasts combined with varying estimates of carbon prices to produce separate evaluations of the impacts on the load and energy forecasts, which include effects from demand-side programs, and new supply-side resources.
- Inflation in plant construction costs and costs of capital:
 - Sensitivity 8 incorporates a higher cost of capital assumption.
 - Sensitivities 9 and 10 analyze the impacts of doubling and tripling the construction cost escalation rates, respectively.
- Availability and costs of purchased power:
 - Sensitivity 11 evaluates the impacts of the availability and costs of purchased power.
- Pending federal or state legislation or regulation:

- Sensitivities 13 through 21 evaluate the impacts of pending legislation or regulation through the scenario planning cases. The impacts of pending legislation or regulation can be analyzed by varying estimates of carbon and fuel prices. The scenario planning cases produce separate evaluations of these impacts on the load and energy forecasts, demand-side programs, unit retirements, and new supply-side resources.
- Rate impact analysis:
 - All of the sensitivities analyze the impacts on rates of the varying changes in assumptions. The rate impacts are included in the Financial Review in Technical Appendix Volume 2.

The Mix Study in Technical Appendix Volume 1 and Financial Review in Technical Appendix Volume 2 provide descriptions of these analyses and the impacts of each sensitivity analysis on:

- The timing, amounts, and types of new capacity needed to meet customers' needs;
- The costs associated with meeting the load growth on the system; and
- System marginal costs.

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7 – INTEGRATION OF DEMAND-SIDE PROGRAMS INTO THE BENCHMARK SUPPLY-SIDE PLAN

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SECTION 7 - INTEGRATION OF DEMAND-SIDE PROGRAMS INTO THE BENCHMARK SUPPLY-SIDE PLAN

7.1 INTRODUCTION

In the integration step, those demand-side programs resulting from the DSM evaluation are integrated with the appropriate benchmark supply plan using the Strategist®/PROVIEW™ model. This method ensures a cost-effective mix of demand-side and supply-side resources are selected, while acknowledging the limits of available demand-side resources.

7.2 DISTRIBUTING CAPACITY AMONG THE OPERATING COMPANIES

In order to make the full benefits of coordinated planning available to the System's operating companies, the mix optimization process is performed for all of the system operating companies. For long-range planning purposes, the generating unit resources resulting from the mix process must then be distributed or allocated among the system operating companies based on their particular needs and current resources. This planned distribution is performed through an analysis of each company's existing resources and energy needs. The actual resource selection is based on the specific operating company needs instead of the planning assumptions. As the time for commitment to new capacity approaches, additional detailed studies are performed to identify the resources for meeting specific operating company requirements. The decision to acquire new generating capacity or demand-side resources will be made by the operating company based on studies of customer needs and the operational, cost, and financial assumptions specific to the operating company and the options available.

See the Mix Study in Technical Appendix Volume 1 for additional details.

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8 – INTEGRATED RESOURCE PLAN

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SECTION 8 - INTEGRATED RESOURCE PLAN

8.1 OVERVIEW

The 2013 IRP projects that the demand for electricity by the Company's customers will continue to grow. Georgia Power must acquire a significant amount of new resources by 2032 in order to reliably serve these new requirements and replace units retired from generating service. The IRP recommends a cost-effective mix of supply-side and demand-side capacity resources to meet future requirements.

8.2 INTEGRATED RESOURCE PLAN

For the period of 2013 – 2022, reflecting reserve sharing for the System, Georgia Power is projected to have sufficient resources to meet customers' needs given the resources approved by the Commission in the 2011 IRP Update and other previous filings, as described in preceding sections. For the year 2023, the Company has a capacity need based on 10 years of projected load growth, and the reduction in system reserves due to increased system loads and the expiration of PPAs currently available to the system. Without reserve sharing, the Company's first year of capacity need is 2021.

The long-term plan for each of the scenario cases varies depending on the assumptions for that case. The Unit Retirement studies of the existing fleet of generating facilities results in the development of an expected MATS compliance plan for existing units, a plan which is shared across all scenarios and sensitivities. For some of the scenario cases, a mix of gas technologies (CTs and CCs) was selected through the planning period when capacity was needed to maintain reliability, meet growing customer needs, or for fuel-cost savings. In other scenario cases, nuclear was selected in addition to certain gas-fired generation, including CCs with CCS, during the planning period when capacity was needed to maintain reliability, meet growing customer needs, or for fuel-cost savings.

The IRP utilizes demand-side resources and acquires the proper mix of capacity through power purchases or self-owned resources (i.e., self-built and/or acquired from existing assets) in sufficient amounts to meet minimum System reliability criteria. The IRP (as shown in Figure 8.2 and Table 8.2 in the IRP Main Document Reference Tables section of Technical Appendix

Volume 1) shows the resource needs for the years 2013 – 2032 based on current environmental requirements and other base case assumptions. When Georgia Power acquires its resource needs through the RFP process, the actual generation technology purchased is dependent on what the market bids to the Company.

8.3 PLAN REVIEW BASED ON OTHER PLANNING OBJECTIVES

The IRP was reviewed based on the additional planning objectives listed below.

- **Flexibility** — Can the plan be altered if the future is different than expected?

Yes. In the near term, the IRP relies on demand-side programs, pricing tariffs, and short-term supply-side purchases when appropriate. Natural gas-fueled capacity proved to be the next supply-side resource needed under the analyses performed in the base case IRP while nuclear is selected in certain scenario planning cases with carbon prices. The relatively short lead time (four years or less) required for a simple cycle CT and the utilization of short-term purchases will provide the flexibility to meet any uncertainties that may arise.

- **Reliability** — Does the plan provide reliable service for all customers?

Yes. The IRP holds System reliability at a level that balances the cost of outages and the cost of new generating capacity.

- **Long-Term Viability** — Will the plan meet customer needs over the long term?

Yes. The IRP adequately provides for needed capacity resources in the future and minimizes the need for rate increases. There is flexibility to alter the plan as needed. Customers have the opportunity to participate in the demand-side program or pricing options that fit their individual needs. The IRP is a viable long-term plan under the current regulatory and operating environment.

- **Environmental** — Does the plan ensure compliance with environmental regulations?

Yes. In addition to complying with all existing laws and regulations, the Company reviews and assesses pending rules, regulations and legislation in regard to environmental issues that may impact Georgia Power and Southern Company. The Company's Environmental Compliance Strategy document is included in Technical Appendix Volume 2. Additional environmental sensitivities and their impact on the generation mix analysis are also included in the Mix Study in Technical Appendix Volume 1 and the Financial Review in Technical Appendix Volume 2.

- **Risk** — Does the plan appropriately mitigate the risk of future changes in conditions?

Yes. There is a risk that the load growth will be more or less than expected, and that the demand-side programs may not be well-received or provide the projected load reductions. There also is risk that there will be more interest in DSM than currently experienced, decreasing the need for new capacity acquisitions. Finally, there is risk associated with uncertainty regarding expected environmental rulemakings and their potential impact on retirement of some existing resources. The plan balances this risk against cost to customers. The Financial Review included in Technical Appendix Volume 2 provides additional information regarding the business and financial risks associated with the IRP.

- **Shareholder Value** — Will the plan provide shareholders with the opportunity to earn a fair return on their investment?

Yes. The IRP process provides for a full review of the need to add new generation resources and the certification of resources chosen to fill those needs. This process provides shareholders with a greater level of certainty that their investments in these certified resources will result in the ability to earn a fair and reasonable return.

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9 – SUMMARY OF TRANSMISSION PLAN

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SECTION 9 - SUMMARY OF TRANSMISSION PLAN

9.1 TRANSMISSION PLAN

This IRP includes the Company's ten-year transmission plan, which identifies the transmission improvements needed (based upon current planning assumptions) to maintain a strong and reliable transmission system. In addition, it contains any necessary transmission improvements related to the Company's compliance strategy, outlined in this document, developed as a result of the EPA's MATS rule. Along with the ten-year plan, Georgia Power has included a comprehensive and detailed bulk transmission plan of the Georgia Integrated Transmission System.

9.2 TRANSMISSION PLANNING PRINCIPLES

The purpose of the transmission planning principles is to provide an overview of the standards and criteria that are used for transmission expansion and upgrade proposals. These principles are designed to help ensure the coordinated development of a reliable, efficient, and economical electric power system for the transmission of electricity for the long-term benefit of the transmission users. These principles also recognize that planning should be proactive in order to ensure timely system adjustments, upgrades, and expansions. The principles that apply to Georgia Power's transmission planning are as follows:

- Identify and recommend projects that are consistent with the Guidelines for Planning the Georgia Integrated Transmission System ("ITS") and the Guidelines for Planning the Southern Company Electric Transmission System;
- Identify and recommend projects that are consistent with the NERC Planning Standards and the SERC Supplement to the NERC Planning Standards;
- Minimize costs associated with the ITS expansion, giving appropriate consideration to system reliability;
- Identify projects with sufficient lead-time to provide for the timely land acquisition and construction of new transmission facilities;
- Recommend budget expenditures that recognize the financial capabilities and limitations of Georgia Power;

- Coordinate transmission system plans with the plans developed by the Transmission and Distribution (“T&D”) Area and Distribution Planning groups, the T&D Planning Section, Distribution, Engineering, Land, Operations, Protection, other ITS members, other Company departments, and the regions surrounding the Southeast to seek their active involvement in the project development and planning process;
- Coordinate transmission system plans with all ITS participants in an effort to enhance reliability and minimize associated costs; and
- Maintain adequate interconnections with neighboring utilities.

These principles provide guidance to planners and/or planning authorities that are called upon to explore existing issues and any future problems encountered in the transmission planning process.

9.3 10 YEAR TRANSMISSION PLAN

Georgia Power is a member of the ITS, which consists of the physical equipment necessary to transmit power from the generating plants and interconnection points to the local area distribution centers in most of Georgia. The ITS is jointly owned by Georgia Power, Georgia Transmission Corporation, MEAG Power, and Dalton Utilities. Transmission planning embodies investment decisions required to maintain the ITS so that it can reliably and economically meet the power needs of the public. Justifications used in any such decisions are based on technical and economic evaluations of options that may be implemented to meet these needs.

Transmission Planning-East (“TP-East”) of the SCS Transmission Planning department is responsible for planning the transmission system for Georgia Power. TP-East, in conjunction with the other participants in the ITS and the interconnected neighboring utilities, develops a model of the transmission system for each year for ten years into the future. These planning models are used to identify transmission problems based on NERC and ITS planning guidelines and to evaluate alternative cost-effective solutions to the problems. Investment decisions must accommodate the fact that future load levels and generation plans are uncertain. This ensures that the planning process does not have to start anew each time a change is made.

All Transmission Planning information is provided in Technical Appendix Volume 3 per the Commission's 2007 IRP Order and the amended rules adopted by the Commission in Docket No. 25981. Additional Transmission Planning information required per Docket No. 31081 is available in Technical Appendix Volume 3.

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10 – RENEWABLE RESOURCES

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SECTION 10 - RENEWABLE RESOURCES

10.1 RENEWABLE RESOURCES OVERVIEW

Throughout its history, Georgia Power has diligently and resourcefully pursued cost-effective opportunities to cultivate renewable generation in Georgia in a responsible manner. As a result of the collaborative efforts of Georgia Power, the Commission, and the renewable energy community, there are currently 11.6 MW of solar generation (with another 50 MW under contract to commence service in the future), 142 MW of biomass generation including landfill methane gas, and 1,088 MW of hydro generation serving customers. Combined, these resources provide enough electric capacity to power the peak needs of more than 257,000 homes. With the introduction of the GPASI, the total amount of solar energy under contract by Georgia Power is expected to be more than 270 MW by the end of 2014. In addition to procuring cost effective renewable resources, Georgia Power also supports research and demonstration of renewable and emerging technologies. In all of these efforts, the Company seeks to responsibly expand the fuel diversity of our supply mix through our commitment to cost effective renewable generation.

10.2 GREEN ENERGY PROGRAM

Georgia Power seeks to provide electricity to customers from renewable generation sources that do not cause rates to increase as compared with other available generation options. To do this, the Company must develop or purchase energy from sources at a cost equal to or below current avoided cost. The Company monitors and participates in R&D to find renewable technologies that it can add to our energy portfolio as these technologies become economically feasible. For customers who are willing to voluntarily cover the additional cost of renewable generation when such costs exist, the Company offers the Green Energy Program.

The Commission approved Georgia Power's Green Energy Program ("Green Energy Program") in 2003 in Docket No. 16573. This order approved both the Green Energy ("GE") tariff for the sale of Green Energy and the Renewable and Non-Renewable Resources ("RNR") tariff for the purchase of Green Energy. After the Company contracted with DeKalb County for the output from the Seminole Landfill generator, the Green Energy Program's primary energy resource, the Company enrolled and began billing customers in 2006.

Again in 2008, in Docket No. 16573, the Commission approved several modifications to the Green Energy Program including the following four options through which customers could purchase Green Energy:

- Standard Green Energy, with a price of \$3.50 per 100 kWh block;
- Premium Green Energy, containing at least two percent solar content for \$4.50 per block;
- A Special Events Purchase Option, allowing customers to purchase Green Energy for a single event; and
- The Large Volume Purchase Option, providing large quantities of Green Energy on a customer specific basis.

At the Commission's request, the Company filed a petition for modification of the Green Energy Program on December 18, 2009 that included a 100 percent solar option priced at \$12.00 per 100 kWh block. Commission Staff proposed a 100 percent solar option at a price of \$9.00 per 100 kWh block. Subsequently, feedback from solar stakeholders indicated that a product with these prices would likely not find acceptance in the marketplace. As a result, on February 18, 2010, the Commission ordered the Company to revise the GE tariff and alter the Premium Green Energy product to include at least 50% of energy from solar resources. Finally on April 20, 2010, in Docket No. 16573, the Commission approved a revised Green Energy tariff, GE-4, that increased the price of Premium Green Energy to \$5.00 per 100 kWh.

Following implementation of the Large Volume Purchase Option, the Green Energy Program experienced considerable growth in sales. Due to the increased interest, the Company needed to procure additional resources to supply the Program, and an RFP was issued for renewable energy to meet the growing customer demand. On March 22, 2010, the Company executed a PPA with WM Renewable Energy, LLC to purchase 100% of the renewable energy from a 6.4 MW landfill gas facility in Savannah.

The Company launched significant marketing efforts to raise participation levels in each of the four product options. Green Energy and solar information is readily accessible on the redesigned GeorgiaPower.com website. A YouTube video is available to explain the features and benefits of the Standard and Premium products and encourage participation. Other social media tools such as Facebook and Twitter raise awareness of the Green Energy Program. Also, the

Company has been successful in obtaining new Special Event contracts by partnering with its Key Account Management employees, who serve the Company's largest customers. Some of the Green Energy Program Special Events include the Atlanta Botanical Garden's "Garden Lights Holiday Nights" event, the Chick-fil-A Bowl, the Athens Clarke Classic Center's Greenlife Expo and the Atlanta Hawks green season purchase.

The Company has maintained a successful level of Large Volume sales. As of June 2012, five customers were purchasing more than 41 million kWh of Green Energy per year. The Company continues to work diligently to meet all reporting obligations set forth by the Commission and the Energy Information Administration. The Company also maintains Green-e[®] certification and successfully meets the stringent requirements of the annual audit. In the fourth quarter of 2011, the Company implemented a Large Volume marketing campaign to proactively target over 60 high potential customers with pricing offers to purchase Green Energy. Although none of these customers executed a contract, many large customers became familiar with options to purchase Green Energy.

In summary, the Green Energy Program serves over 4,000 participants that voluntarily pay more to support energy generation from renewable resources. The Green Energy Program has stimulated the growth of renewable resources in Georgia and is directly responsible for 9.6 MW of landfill gas and 5.4 MW of solar generation. However, challenges lie ahead. The Green Energy Program is currently under-recovered due to low avoided energy costs and flattening sales. Furthermore, as a result of available tax credits, rebates, and other distributed generation purchase programs, some customers have chosen to install their own renewable resources rather than purchase through the Green Energy Program. The Company will continue to monitor these developments and work with the Commission and stakeholders to implement Green Energy Program improvements.

10.2.1 Distributed Generation Energy Purchases

The RNR tariff was approved as part of the Green Energy Program in 2003. Georgia Power purchases a portion of its renewable energy from distributed generation resources through the RNR tariff. The tariff offers two metering options: bi-directional metering and single directional metering. Bi-directional metering allows customers to offset their usage and sell any excess

energy back to the Company at the Company's avoided energy cost. Single directional metering allows customers to sell 100% of the output of their solar panels, plus any associated Renewable Energy Credits ("RECs"), to the Company at a premium price.

Bi-Directional Metering: The RNR tariff provides a means for Georgia Power to comply with the Georgia Cogeneration and Distributed Generation Act of 2001 and allows for the purchase of this energy at avoided energy cost in compliance with the Commission's final order in Docket No. 4822.

Single Directional Metering: At the inception of the RNR tariff, a total capacity cap of 500 kW was established for purchases of energy from solar resources at premium pricing. On August 4, 2009, the Commission, in Docket No. 16573, increased the capacity available for the premium solar price by 1,000 kW to a total of 1,500 kW. Despite these considerable increases in capacity, there continued to be a significant waiting list for single directional metering through the RNR tariff as customers sought the guaranteed premium pricing to help make their solar projects viable.

As part of the 2010 IRP, the Company sought approval to raise the cap by an additional 1,000 kW to 2,500 kW total. The Commission approved this request and also implemented a mechanism whereby the capacity cap would automatically increase with additional sales of Premium Green Energy. Under this method, sales of 219 additional blocks of Premium Green Energy would result in a 100 kW increase in the capacity cap of the RNR tariff. The Company was able to grow the sales of Premium Green Energy by converting the required monthly buy-through of Large Volume customers to Premium from Standard Green Energy. As a result, the Company increased the capacity cap of the RNR tariff by 400 kW to a total of 2,900 kW. The new total capacity cap was split, with 500 kW reserved for projects with a peak generating capacity of 25 kW or less and 2,400 kW reserved for applications of greater than 25 kW but not more than 100 kW.

In September 2010, the Company proposed to modify the Green Energy Program by adding the Solar Purchase ("SP") tariff and changing the RNR tariff. On December 31, 2010, the RNR tariff was closed for additions of energy purchased from solar photovoltaic resources at prices above avoided energy cost. Pursuant to Docket No. 16573, the Company continues to purchase

energy from solar resources through the single-directional metering option of the RNR tariff at the Solar Purchase Price—currently set at 17¢ per kWh. The RNR bi-directional metering option continues to exist for avoided energy purchases in compliance with the Commission’s final order in Docket No. 4822.

The new SP tariff allowed for an additional 1,500 kW of solar capacity to be purchased at the new Solar Purchase Price of 17¢ per kWh, which increased the Company’s total solar capacity at premium pricing to 4,400 kW. This new capacity was split by facility size, with 85 percent of the capacity for facilities greater than 25 kW but not more than 100 kW and 15 percent of the capacity for facilities 25 kW or smaller. In addition, the Company was approved to issue a Solar RFP through which it would purchase another 1,000 kW of capacity at a price of 15¢ per kWh or less.

Georgia Power issued the RFP on May 3, 2011. There were three bidders that submitted four bids, with Solar Design & Development, LLC (“SDD”) selected as the winning bidder. On December 8, 2011, the Company executed a contract for the purchase of solar energy and RECs from SDD. SDD designed, developed, and installed a solar PV generation facility consisting of approximately 4,255 solar panels located in Hannahs Mill, Georgia with a total capacity of 1 MW of electric power.

Georgia Power has executed additional contracts to fill the new SP tariff capacity and continues to maintain an extensive waiting list for this premium pricing.

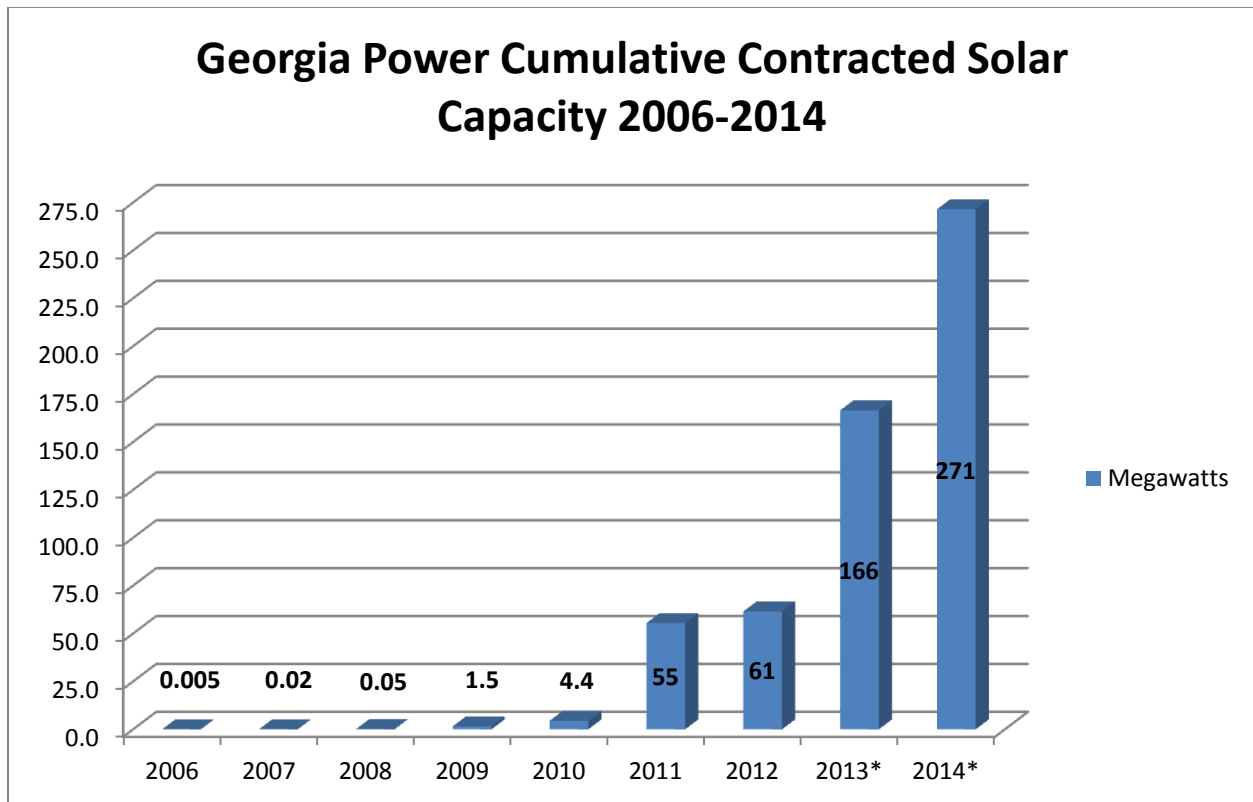
10.2.2 Community Supported Projects and Capacity Exceptions

In the 2010 IRP, the Company proposed a methodology for accepting community sponsored solar projects in response to a large number of requests for this type of offering from solar developers. This method allows developers to solicit community support for solar projects and be granted an exemption to the SP capacity cap. The community supporters would need to purchase an additional 219 blocks of Premium Green Energy in order for a 100 kW solar project to be constructed. Currently, no developers or customers have participated in this program.

10.3 OVERVIEW OF ADDITIONAL SOLAR INITIATIVES

Driven by an extended period of declining solar module and balance of system pricing, Georgia Power has received Commission approval to responsibly grow the solar portfolio for customers by 260 MW through the GPASI and LSS programs. These programs allow for procurement of distributed and utility scale solar projects in the state without inducing any incremental upward rate pressure on customers. In addition, the Company also continues to contract with solar projects as QFs at the Company's avoided cost rate. Several of the QF solar projects as large as 1.5 MW in size have been under contract since 2011.

The following graph illustrates the expected cumulative contracted solar capacity for Georgia Power through 2014.



*Projected Under GPASI

The reduction in solar installation costs over the past 24 months is expected to result in an increase of distributed solar projects in the service territory. Therefore, it is important for the Company to fully account for all the impacts of distributed generation on the electric distribution

system as well as to customers. Within the next few years, the Company intends to evaluate a pilot scale demonstration project that assesses the benefits and challenges associated with combining solar and Conservation Voltage Reduction (“CVR”). CVR is an active measure that reduces customers’ electricity demand by temporarily lowering the customer’s service voltage, while maintaining reliability. An increased amount of CVR demand reduction may be used to coincide with diminishing solar output that occurs during afternoon peak demand hours. The pilot project would analyze existing solar on the electric grid in combination with CVR to determine if there are any system benefits realized by this methodology.

10.3.1 Large Scale Solar

On June 7, 2011, the Commission requested that Georgia Power and Commission Staff develop options for expanding large-scale solar projects. In response to the Commission’s request, the Company developed the 2015 LSS proposal. The Commission approved the Company’s LSS proposal on July 22, 2011 in Docket No. 34229 and ordered the Company to file the LSS program’s procedural details within 30 days.

Under the LSS proposal, the Company purchased a total of 50 MW of solar capacity. This purchase was in addition to the Company’s current solar procurement activities and will add to the generation procured through the 2015 RFP. The Company entered into PPAs for terms of 20 years for individual solar projects in Georgia that were greater than 1 MW, but less than or equal to 30 MW in size.

These purchases were for a fixed energy amount at a preset solar price per MW hour (“MWh”) throughout the term of the PPA. The pricing was developed utilizing projected long-term avoided energy costs, plus a credit for the capacity that solar provides. The capacity component of the solar price was benchmarked to current market pricing obtained in the 2015 RFP. Under this avoided cost/market pricing methodology, customers were assured that the capacity resource procured was consistent with current economics while also gaining the benefit of additional fuel diversity. Participants kept the rights to the RECs produced by their projects.

Commission Staff conducted a first-come, first-served Notice of Intent process in September 2011 and notified the Company of the winning participants. The Company subsequently negotiated, executed and received approval for all 50 MW of contracts. These projects have a required commercial operation date in 2015 but are projected to become operational as QFs sometime in 2013 and 2014.

10.3.2 Georgia Power Advanced Solar Initiative

On September 26, 2012, Georgia Power filed the GPASI in Docket No. 36325. This initiative complements other ongoing efforts to pursue cost-effective renewable resources and was designed to maximize opportunities for solar development by encouraging wider participation. The approach was simple: provide opportunities to develop solar resources (from small roof top to utility-scale), including mechanisms by which multiple entities can participate in that development. To that end, the GPASI program is expected to stimulate solar development in a cost-effective, responsible way that will bring additional solar generation to the Company's customers.

The resources procured under the GPASI will be in addition to the solar resources the Company currently procures through the Commission-approved Green Energy contract, SP and RNR tariffs, the LSS program, and other QF purchases.

Through the GPASI, the Company will purchase energy from solar generation in two distinct ways: through (1) requests for proposals (the "GPASI RFPs") from solar developers to fulfill an annual portfolio capacity target; and (2) smaller, distributed scale solar purchase offerings.

Under the GPASI RFPs, Georgia Power expects to purchase up to 60 MW of utility scale solar generation per year, for two years, for a total procurement of 120 MW. Specifically, beginning in 2013, the Company will issue an RFP for 60 MW of additional solar, with an expected commercial operation date ("COD") of January 1, 2015. In 2014, the Company will issue another RFP for 60 MW of new solar, with an expected COD of January 1, 2016. The Company will enter into PPAs for a term of 20 years for individual solar projects in Georgia that are greater than 1 MW and less than or equal to 20 MW in size. Each RFP will require bidders to

bid a “not-to-exceed” price of 12 cents per kWh, the calculation of which includes a capacity benefit that is benchmarked to market pricing obtained in the 2015 RFP in Docket No. 34218.

The second component of the GPASI involves smaller solar facilities, up to 100kW in size, and mid-sized facilities, greater than 100 kW up to 1 MW in size. These two distributed scale solar purchase offerings are referred to as the “Small-Scale” and “Medium-Scale” options. Under the Small-Scale and Medium-Scale options, Georgia Power will purchase 90 MW of solar generation from customers and developers that are located in the Company’s service territory over a period of two years beginning in 2013, with any unused capacity rolled over to subsequent years. The Company will enter into contracts to purchase 100 percent of the energy from the solar capacity from both its retail customers and private developers at 13 cents per kWh. The Small/Medium Scale programs will procure a total of 45 MW of energy from the new solar capacity on a first-come, first-served basis each year, for two years, until the 90 MW limit is met.

The GPASI was approved on November 29, 2012 and makes Georgia Power one of the national leaders among utilities operating in states in which there is no mandate for solar procurement.

10.3.3 Distributed Solar Demonstration Projects

There are three solar demonstrations underway at Southern Company facilities. The first is located on the roof of the Georgia Power headquarters building in Atlanta, Georgia. The objective of this pilot-scale demonstration is to compare the performance and reliability of different commercially available PV technologies. Five technologies were installed by the end of the summer of 2009. The remaining two systems were installed in 2010. The Company has begun an evaluation to determine which technologies are best suited for the unique climate conditions of the southeastern United States. Preliminary results from the ongoing evaluation were published in an internal report by the Electric Power Research Institute (“EPRI”) in January 2013 with a final report expected to be expected March 31, 2013. The demonstration project has already served as an educational platform for customers who are in the process of evaluating solar projects. The Company has hosted over 150 tours of the demonstration and also established a solar dashboard with internet access where stakeholders can see near real-time (15 minute intervals) and historical production data for each of the technologies, along with associated weather data from the project’s weather station.

The Company seeks to revise the solar demonstration project at the Georgia Power headquarters building into a second phase once the final results of the initial solar demonstration are complete. The Company wishes to expand the demonstration project as a test bed for commercially viable solar technologies. The evolution of solar technologies requires that the Company continue to evaluate and test evolving commercial technologies to understand their performance in the unique climate of the Southeast. Upon completion of the initial phase, as outlined above, the Company intends to update the existing solar systems on the roof to reflect the most recent and emerging solar technologies. These technologies may include solar technologies developed locally and regionally. The research goals of the demonstration project would remain the same through evaluation of environmental impacts such as sunlight hours, temperature and humidity. The project will also seek to maximize output from the solar projects through a variety of system orientation and optimization factors.

In addition, the Company seeks to implement a battery storage demonstration project as a compliment to the existing Georgia Power headquarters building solar demonstration. A battery storage system could be installed on one or more of the 4kW solar modules to help evaluate the benefits and costs of battery storage. This battery storage system would allow the output of a solar project to be shifted several hours to better align it with the summer peak of the utility. The Company expects the cost of modifying the Georgia Power headquarters building solar demonstrations to add both the battery storage evaluation and the newest commercially viable technologies would not exceed \$200,000. Understanding this technology, including cost, operation, and maintenance will provide the Company valuable market knowledge and experience to assist customers with future inquiries. Much like the reporting for the first phase of the Georgia Power headquarters building solar demonstration project, the Company would work with a third party to document the results of the second phase of the demonstration project. As battery technology costs continue to decline, this project will provide the company with key technology performance information to identify the appropriate role of solar generation with storage in the company's portfolio.

A second solar demonstration project, conducted by Southern Company Research & Environmental Affairs, is located on the rooftop of the Alabama Power headquarters building in Birmingham, Alabama. The objective of this pilot-scale demonstration is to gain system-wide

experience with micro-inverters being used on different commercially available solar technologies and to compare different module technologies, similar to the Georgia Power demonstration project. In addition to comparing energy production from various solar PV technologies, the Company will gain valuable information on the impacts of weather patterns on solar PV generation. The equipment was installed in 2010. This project is also being conducted in conjunction with EPRI and the results from the ongoing evaluation will be published in an internal report by March 31, 2013.

The third System solar demonstration project, also conducted by Southern Company Research & Environmental Affairs, is located at an Alabama Power facility in Mobile, Alabama. This site has seven ground-mounted systems, each with a capacity of approximately 2 kW, and has been in operation since October 2011. This project continues the work of the previous two projects but will focus on the specific effect of coastal weather on solar output.

In addition to the original evaluation and demonstration goals of these three projects, data from these installations are being used to evaluate both weather and PV generation modeling and simulation tools. Most of the widely adopted models used to generate solar resource data (such as those used to make the National Renewable Energy Lab's solar resource maps) were designed relying heavily on modeled data. Combined, these demonstration projects are helping Georgia Power in the evaluation and refinement of these types of models, while also aiding in the development of more accurate generation profiles for system planning and other activities.

10.3.4 1 MW Solar Self-Build Demonstration

In the 2010 IRP, the Commission approved the Company's request to develop a portfolio of solar demonstration projects totaling up to 1 MW to evaluate solar project siting, procurement, construction, and maintenance. The Company has evaluated several potential solar projects, including high profile sites at customer locations as well as installations at or on Company-owned facilities. The Company will continue to seek optimal locations to install this portfolio of projects totaling 1 MW and gain valuable experience in installing, owning and operating solar PV projects.

10.3.5 EPRI Distributed Photovoltaic (DPV) Project

Fifty solar PV units were installed on power poles located along selected Georgia Power distribution feeders in 2010. Another group of approximately 50 PV units was installed on selected distribution feeders in the Alabama Power service territory in 2011. The one-second data collected will be used to determine the impact of adding PV to the distribution system, to better understand the variability of PV performance, and to characterize other grid interface issues associated with this variable generation source. Among other benefits, these results could lead to a more effective and efficient interconnection process. Results from the ongoing evaluation of these PV units will be published in a report by EPRI in the first quarter of 2013.

10.3.6 Solar PV Tracking and Orientation Study

Due to the increasing prevalence of tracking technologies for solar PV applications and the potential for different orientations of fixed systems to have different impacts on capacity value (e.g., a west-facing system would have a peak output at a time that may better coincide with Georgia Power's summer load peak), Georgia Power and Southern Company are considering a research project and demonstration involving different tracking technologies and system orientations.

This project could test and demonstrate 250kW installations of each of the following technologies:

- Fixed-tilt, south facing PV panels (most standard technology, would serve as a control)
- Fixed-tilt, southwest facing PV (improved capacity value, decreased annual energy)
- Single-axis tracking (advanced technology, but becoming more common)
- Dual-axis tracking (most advanced technology)

This 1 MW solar PV tracking and orientation project would evaluate the performance and operating characteristics of each configuration, using the same panel and inverter technology for each. The Company estimates that the cost of this demonstration will not exceed \$5,000 per kW installed. Results would provide valuable operation data, as well as enable Georgia to gain

experience with these more advanced technologies. A real-time dashboard, similar to the current rooftop PV projects, may be provided for additional education purposes.

10.3.7 Concentrating Solar Thermal Applications Research

Southern Company participated in two supplemental solar projects with EPRI from 2008 to 2010. These studies involved assessing the economics and feasibility of adding steam generated by a solar thermal field to a conventional fossil fuel-powered steam cycle, either to offset some of the fossil fuel required to generate electric power or boost plant power output. These were computer simulation projects, and the parameters entered came from actual coal and natural gas plants. The final reports are available to participants in supplemental projects. These studies found that this application is not currently feasible, due to the economics of the technology and the lack of the specific type of solar resource required for concentrating solar technologies in the Southeast.

Southern Company began participating in a supplemental project with EPRI in 2012 that will evaluate the potential for a lower temperature application of concentrating solar thermal technology. This study will be based on the thermal requirements of the carbon capture process in the 25MW carbon capture demonstration at Alabama Power's Plant Barry near Mobile, Alabama. This application has potential to be better suited for integration of concentrating solar technology to offset the parasitic load on the plant induced by the chemical processes involved in carbon capture from flue gas.

10.3.8 Solar Water Heating Demonstration Projects

Eighty-gallon propylene glycol solar water heating systems were installed at four residences in Pensacola, Florida; Saraland, Alabama; Bainbridge, Georgia; and Long Beach, Mississippi. The objective of this project is to generate performance, reliability, and cost information sufficient to quantify the economics and technical viability of solar water heating applications across Southern Company's service territory. The last of the four systems was installed during the summer of 2009, and data review has begun for all four sites. An internal project update report was issued during the first quarter of 2012. Data collected to date suggest that the solar thermal collectors can provide 70% or more of the annual energy needs for water heating, but system

reliability and cost could still be issues. Completion of data collection is anticipated during the second quarter of 2013, with a final report expected to be completed by the end of 2013.

10.3.9 Additional Solar Related Resources Available to Customers

The Company has also taken steps to provide more information and education for customers interested in learning more about solar generation options. For instance, the Company selected and trained 18 employees to serve as Solar Energy Consultants. These Solar Energy Consultants are located throughout each of the Company's 11 regions across the state and are sources of information for customers who are interested in solar. In addition, information available on GeorgiaPower.com also aids customers in the evaluation of available solar generation options. The Company has received positive feedback regarding its Solar Energy Consultants and the additional solar-related information available at GeorgiaPower.com. These efforts support Georgia Power's goal to provide expertise to its customers as they make energy decisions.

10.4 90 MW RENEWABLE SELF-BUILD PROJECT

As part of the 2007 IRP, the Commission approved the Company's request to develop up to three 30 MW renewable energy projects that are at or below the Company's avoided cost.

The Company continues to seek cost-effective renewable projects and has either evaluated, or is currently evaluating, landfill methane gas, digester methane gas, wood biomass, and solar PV projects with developers and customers. To date, evaluations have been made on over 30 potential biomass, landfill methane gas, or digester methane gas projects and over 50 potential PV solar projects. However, no commitments have been made for specific self-build projects.

Contributing factors that have affected the development of renewable projects are:

1. Decreases in current projected avoided costs relative to prior projections, largely due to lower natural gas price forecasts, have made financial hurdles more difficult to clear.
2. Uncertainties created by pending EPA regulations and lower natural gas prices may adversely affect the economic viability of the biomass repowering projects.

10.5 BIOMASS OVERVIEW

The Company continues to evaluate a variety of biomass generation options. Decisions on individual projects will depend on costs, regulatory/legislative requirements, biomass fuel availability and other site-specific factors.

Southern Company is conducting research at multiple locations on co-firing coal with wood chips, wood pellets, sawdust, urban wood waste, peanut hulls, switchgrass, and other biomass to determine the costs and impacts of the process. Additionally, Southern Power began commercial operation of a 100 MW biomass plant in Sacul, Texas on June 23, 2012. The plant will serve the city of Austin for 20 years and is one of the largest 100 percent biomass plants in the nation.

10.5.1 Biomass Cofiring

The scope of Southern Company's biomass testing program has included investigation of co-firing various types of biomass at existing pulverized coal power plants. Several studies have been conducted by Southern Company and Georgia Power regarding the feasibility and cost-effectiveness of different co-firing technologies.

Southern Company has been working to develop a better understanding of the technical, environmental, and cost issues associated with co-firing up to 10 percent biomass by energy through direct injection in coal units. The studies defined the required additional equipment, equipment modifications, performance, environmental emissions, and costs associated with adding the biomass direct injection system to coal units. KEMA and Doosan were the Company's contractors for these studies. The contractors also assessed the impacts of co-firing up to 10 percent biomass by energy on downstream emission control equipment. These studies were performed at units in Alabama and Georgia.

In general, there are two forms of co-firing. Co-milling involves treating the biomass as if it were coal, mixing the material with the coal and passing it through the coal handling system and coal burners. The other technology is direct injection, in which the biomass is processed to a fine sawdust-like material and blown directly into the furnace through its own dedicated burners or with the coal through existing burners. Co-milling requires less capital but is limited to only low percentages of biomass. Its success depends on the individual power plant design, the form

of biomass as fuel, and the percentage co-fired. The maximum percentage of co-milling energy will typically be about one to five percent as measured by energy input. In testing at Southern Company plants, sawdust and sander dust worked fairly well, as did finely chipped tree trimming waste. Less success was achieved with large wood chips due to their fibrous nature. Smaller wood chips, 1/2 inch or less in fiber length, worked better than the larger chips, but not quite as well as sawdust.

Direct injection is generally capable of co-firing higher percentages of biomass. However, capital equipment is required, and the biomass (wood or grass) must be reduced to a small size, which can further add to costs. Encouraging results have been obtained in Southern Company power plant tests conducted on direct injection of switchgrass.

In addition to the biomass handling, feeding, and capital cost issues mentioned above, there are other key technical hurdles that must be overcome before biomass could be co-fired on a significant scale. Biomass materials have concentrations of certain minerals that are potentially adverse to the operation of the pollution control equipment located at many of the Company's power plants. Southern Company is currently pursuing R&D to better define the effects of these minerals. Furthermore, many plants sell, rather than store, their fly ash for use in the concrete industry. However, the American Society for Testing and Materials ("ASTM") International specifications for fly ash in cement does not recognize anything but fly ash from coal. As a result, there are concerns about the ability to sell fly ash that contains wood ash. Southern Company continues to partner with Georgia Tech to study the differences in coal only ash and biomass co-fired ash as discussed more fully below.

The current financial projections show that co-firing biomass can be economical with conventional coal-based power generation. Because a given volume of biomass contains much less energy than the same volume of coal, the transportation costs for biomass versus coal are much greater. This cost relationship adversely affects the economics of biomass power generation. The Company currently estimates that Georgia Power could realistically co-fire biomass to produce energy in the range of 30 to 80 MW at selected units.

Southern Company will continue to conduct a significant R&D program in biomass co-firing with the goal of solving the key technical issues and improving the economics. Southern

Company is actively engaged in addressing the technical issues and economic barriers that will permit increased use of this native resource for future power generation.

Southern Company has completed a series of small (1/2 inch and less) wood chip co-milling tests. The tests were conducted at units across the Southern Company fleet. The project explored the feasibility of using woody biomass as an energy source by blending it with coal and sending the fuel mix through the existing fuel handling system. The overall percentages of woody biomass that could be co-milled ranged from zero to three percent by energy. This number is lower than initially expected and is greatly influenced by excess pulverizer capacity, pulverizer type and fuel moisture. A test with wood pellets was also recently performed at an Alabama Power coal plant. During the test, a seven percent blend of wood by energy was achieved. Additional co-milling studies will be performed with torrefied wood as the fuel type at a Gulf Power coal unit in the near future. Torrefied wood is wood that has undergone extensive drying and heating and has the potential to be blended at very high percentages with coal, but the market is still in the pre-commercial stage, and it is very expensive when compared to coal or green wood pellets.

The Company, in conjunction with Southern Company, has evaluated several aspects of biomass co-firing at units across the fleet to determine feasibility and potential long term benefits. In addition, the prospect of complete conversion to biomass from coal is being evaluated at Plant Mitchell near Albany, GA.

10.5.2 Plant Mitchell Unit 3 Biomass Conversion

On March 26, 2009, the Commission certified the conversion of Plant Mitchell Unit 3 from a 155 MW coal-fired electric generating station to a 96 MW biomass fuel-fired electric generating station (the “Mitchell Project”).

At the time the certificate was issued, the Mitchell Project was expected to begin serving customers in the summer of 2012. However, subsequent to the Commission’s decision, the EPA delayed the release of the IB MACT regulation several times. The IB MACT regulation limits emissions from industrial boilers and applies to biomass-fired electric generating boilers. As a

result of the anticipated impact of EPA rulemakings on the Mitchell Project, the Company requested, and the Commission approved, a delay in construction of the Mitchell Project.

On October 26, 2011, at the Company's request, the Commission approved an additional two to four year delay due to uncertainties relating to pending EPA regulations.

On December 2, 2011, the EPA issued a proposed IB MACT rule as part of its reconsideration of the rule that was finalized on March 21, 2011. As with prior versions of the rule, the newly proposed reconsideration contains stringent emission limits for several hazardous air pollutants.

In a May 9, 2012 order, the Commission approved the Company's plan to study the feasibility of using Direct Injection ("DI") technology for the Mitchell Project. The Commission also ordered the Company to provide the Commission Staff the results of the DI study no later than the Company's 2013 IRP filing. The Company shared the results of the study with the staff in January 2013. The study defines the required equipment modification, performance, environmental emissions, and cost associated with using DI for the Mitchell Project.

On December 14, 2012 the EPA released a new National Ambient Air Quality Standard ("NAAQS") for PM_{2.5}. The Company is evaluating the new standard for any potential impacts on the Mitchell Project. The EPA originally planned to issue the new IB MACT rule in the spring of 2012. On December 21, 2012, the EPA issued the final reconsideration of the IB MACT rule. The Company is currently evaluating the rule and its impact on the Mitchell Project.

10.6 WIND ENERGY

Georgia Power and Southern Company are studying the feasibility of locating wind turbines on and offshore in the Georgia and Gulf of Mexico coastal regions. Past research results suggest that further evaluation is needed to determine exact resource potential for offshore wind. The Company proposes to continue evaluation of offshore wind in addition to exploring resource availability along coastal corridors and Appalachian ridge tops. Despite the uncertainty surrounding the future of production tax incentives, the Company is committed to continued evaluation of wind as a potential energy source both within and outside the service territory.

10.6.1 Proposed Small Wind Demonstration Pilot Project

Georgia Power and Southern Company are evaluating a potential project to compare and evaluate several different small to medium (20-100kW) wind turbine technologies. Between four and six small wind turbines, of both horizontal and vertical axis designs, would be installed in the Georgia Power service territory. Participation from Georgia universities would be sought, with the potential for the project to be managed by a university research program. The intent of the demonstration would be to understand the feasibility of small scale wind generation as well as evaluating wind resources in various geographic areas of the state. These efforts are in addition to the Company's continuing evaluation of utility scale off-shore wind installations. The Company expects the cost of the Small Wind Demonstration Pilot Project not to exceed \$9,000 per kW installed.

10.6.2 Georgia Coast Offshore Wind Feasibility Study

Southern Company and Georgia Tech's Strategic Energy Institute collaborated on a study of the feasibility of locating wind turbines off the coast of Savannah, Georgia. The goal of the project was to determine if offshore wind power is an efficient and cost-effective renewable energy option for power generation. Design and conceptual engineering for the project was completed using technical expertise from both Georgia Tech and Southern Company. The study evaluated various technology options for wind turbines, platforms/foundations, submarine cabling, and grid interconnection. Detailed analyses of a site location and environmental regulations and jurisdictions, including permitting requirements, were also performed. A final report, titled Southern Winds, was completed in early 2007.

One of the findings of Southern Winds was that wind resource data were needed from the actual sites of the potential wind farm. Since 2007, work has continued to obtain offshore leases from the Department of Interior's Bureau of Ocean Energy Management ("BOEM") under its interim policy. An application was submitted to BOEM on April 7, 2011. An interim lease, if granted, would be for five years and only allow for the placement of a data collection system such as a fixed offshore meteorological tower for wind data collection. An addendum to the application has been submitted that would allow for a floating buoy with Light Detection and Ranging

(“LIDAR”) wind measurement technology as a possible lower cost alternative to a fixed meteorological tower.

Following a BOEM Additional Information Request regarding the LIDAR alternative, a response was submitted in November 2012. Initial National Environmental Policy Act lease application process steps began as BOEM issued a December 2012 Federal Register Notice of Intent to prepare an Environmental Assessment, requesting public comment on the lease application. Coincidentally, following a previous Request for Information from the Department of Energy regarding any offshore energy resource evaluation efforts, a response was submitted in September 2012 updating them on the Company's efforts.

10.6.3 Gulf Coast Wind Measurement Project

A meteorological tower was installed at Navarre Beach, Florida, to examine the wind speeds along the Gulf Coast and their potential to match the utility load profile. The site on which the tower was installed is a strip of beach between the Gulf of Mexico and the Intracoastal Waterway. After the tower was installed in September 2009, data was collected at three different heights (40, 50, and 60 meters). The data have shown that the site is only a marginally acceptable resource for wind power generation, having an NREL Class 2 wind power density, while Class 4 is generally considered necessary for economically viable generation.

This meteorological tower was relocated in the second quarter of 2012 to the Navy Construction Battalion Center in Gulfport, Mississippi. Measurement readings began on June 1, 2012, and data is being shared with the Navy and the University of Southern Alabama meteorology department. The meteorological tower will remain in Gulfport for at least two years.

10.6.4 Off-System Wind Projects

On December 7, 2012, Alabama Power started receiving energy from the Oklahoma-based Chisholm View Wind Project as part of a 2011 PPA. This agreement is a 20-year contract through TradeWind Energy. Under this agreement, Alabama Power has the flexibility to use generated wind energy to serve customers and retire the associated RECs or sell the energy and RECs to others, either separately or bundled together. The Chisholm View Wind Project will produce up to 202 MW and is located in Grant and Garfield counties, Oklahoma.

Georgia Power is also evaluating the procurement of wind energy generated from wind farms across the Midwest and moving that power through existing transmission to the Southern Company service territory. Market conditions and transmission availability may allow for the procurement of wind resources that could be below current avoided cost projections. In addition to seeking opportunities to integrate various renewable energy resources to diversify the Company's energy portfolio, the opportunity exists to put downward pressure on rates through purchasing cost effective wind energy generated in the Midwest.

10.7 INCREMENTAL HYDRO OVERVIEW

Georgia Power and Southern Company continue to identify and evaluate opportunities for incremental hydro resources. Incremental hydro refers to the incremental energy, ancillary benefits associated with transmission and, in some cases, incremental capacity obtained by upgrading existing hydro facilities. Upgrades to existing facilities are usually site specific and could range from replacing worn equipment (such as turbine runners) to replacing the entire powerhouse or installing a new powerhouse in an underutilized impoundment. Engineering studies have been completed to assess the feasibility and cost of upgrading certain Georgia Power hydro resources to better understand the improvement of unit efficiency and licensing constraints. Future economic studies will be completed subsequently to determine the timing and/or conditions appropriate for implementing any of the upgrades. If appropriate, the Company anticipates it would likely bring such projects before the Commission for approval prior to starting construction.

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11 – HYDRO ELECTRIC OPERATION AND RE-LICENSING

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SECTION 11 - HYDRO ELECTRIC OPERATION AND RE-LICENSING

11.1 FOREWORD

Georgia Power operates 18 Hydro Electric Facilities and has an ownership interest in a 19th for a total of 71 generating units in Georgia. All but one of these facilities (Estatoah) is licensed under the Federal Power Act. These facilities provide 1,088 MW of capacity and have provided approximately 1,816,716 MWh of energy to the customers of Georgia over the 20-year period from 1993 to 2012. The following information details the re-licensing dates, schedules, requirements and estimated risk of environmental challenges to continued operation of these facilities.

11.2 GEORGIA POWER HYDRO PLANT RE-LICENSING SCHEDULE

The following description applies to re-licensing proceedings that will be ongoing over the next twenty years.

Bartletts Ferry

License Expires 12/14/2014

The Notice of Intent to File Re-License Application was submitted in May 2009. Consultation with stakeholders continued through December 2012, when Georgia Power filed its license application with the Federal Energy Regulatory Commission (“FERC”). The FERC is expected to issue a new license by December 2014 that will likely include environmental enhancements. The scope of these potential enhancements is likely to include enhancements for dissolved oxygen, reservoir fluctuation limits, and improvements to recreation facilities.

Georgia Power has spent and is expected to spend the following for re-licensing Bartletts Ferry:

2008:	\$207,000
2009:	\$525,000
2010:	\$866,000
2011:	\$871,000
2012:	\$1,000,000
2013:	\$400,000
2014:	\$400,000
2015:	\$260,000 (budgeted post-license enhancements)
2016:	\$1,000,000 (budgeted post-license enhancements)
	=====
Total:	\$5,529,000

Wallace Dam

License Expires 6/01/2020

The Re-license process is scheduled to start in 2013; a Notice of Intent to File Re-license Application must be filed prior to June 1, 2015.

Expected Costs of Re-licensing Wallace Dam:

2013:	\$200,000
2014:	\$300,000
2015:	\$1,000,000
2016:	\$1,000,000
2017:	\$1,000,000

The remaining years have not been budgeted but are expected to be of similar magnitude.

Langdale, Riverview, and Lloyd Shoals Projects

License Expires 1/01/2024

The Re-license process is scheduled to start in 2017; a Notice of Intent to File Re-license Application must be filed prior to January 1, 2019.

Rocky Mountain Pumped Storage Project (Co-owned and Jointly Licensed with Oglethorpe Power)

License Expires 1/01/2027

The Re-license process is scheduled to start in 2020; a Notice of Intent to File Re-license Application must be filed prior to January 1, 2022.

Sinclair Project

License Expires 5/01/2036

The Re-license process is scheduled to start in 2030; a Notice of Intent to File Re-license Application must be filed prior to May 1, 2031.

North Georgia Project (includes Burton, Nacoochee, Terrora, Tallulah, Tugalo, Yonah)

License Expires 9/01/2036

The Re-license process is scheduled to start in 2030; a Notice of Intent to File Re-license Application must be filed prior to September 1, 2031.

11.3 REQUIREMENTS AND RISK TO RE-LICENSING REQUIREMENTS

Georgia Power is not currently considering any changes to its operations for the re-licensing proceedings at Bartletts Ferry and Wallace Dam. However, during re-licensing, requirements may be imposed by the FERC (resulting from input from federal and state agencies, non-governmental organizations, and other stakeholders). Outside of the FERC re-licensing proceeding, requirements may be imposed during a license term by the U.S. Fish and Wildlife Service, U.S. Forest Service, or National Park Service through prescriptive authority under the Federal Power Act or by state agencies under Section 401 permits of the Clean Water Act.

Any of these potential requirements can lead to the following impacts or risk to the Company's continued operation of hydro projects.

Risk

Loss of generation and/or capacity from:

- Increased minimum flows;
- Seasonal limits on generation;
- Increased water withdrawals;
- Limits on reservoir fluctuations; or
- Dam removal (less likely for larger hydro projects).

Reduction in peaking capability, reliability, ancillary services (e.g., voltage control), and operational flexibility from:

- Imposed ramping rates; or
- Modifications to current operational regimes.

Increased capital investments arising from:

- Installation of fish passage facilities;
 - Installation of environmental enhancement facilities (e.g., dissolved oxygen);
 - Installation of additional recreation facilities;
 - Shoreline changes;
 - Habitat enhancement;
- 1) Monitoring and surveillance of environmental parameters; or
 - 2) Replacement of capacity/energy.

12 – WHOLESALE GENERATION

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SECTION 12 - WHOLESALE GENERATION

12.1 OVERVIEW

In recent years, the Company has offered certain wholesale capacity blocks to the retail jurisdiction pursuant to the Company's agreement with Commission Staff in Docket No. 26550. The recent decisions on returning wholesale capacity to retail are described below. The Company's requirements service contract with the city of Hampton ended on December 31, 2012. The Company is considering additional potential long-term requirements service agreements with certain wholesale customers as described below. The Company has also signed new long-term contracts to serve Flint EMC.

12.2 WHOLESALE CAPACITY TO RETAIL

On July 27, 2009, the Commission issued an order in Docket No. 26550 accepting into retail Blocks 5 and 6 offer of 178 MW of oil-fired peaking capacity. Portions of the Blocks 5 and 6 capacity will become available to retail at different times as the existing wholesale contracts expire, with the total capacity in retail rate base on January 1, 2016. With the retirement of the Mitchell 4C unit in March 2012, the capacity is reduced to 169 MW and will remain in retail rate base until the end of the assets' lives. The Commission certified Blocks 5 and 6 on March 5, 2010.

On September 15, 2009, the Commission issued an order accepting approximately 78 MW of Scherer Unit 3 coal-fired capacity. Approximately 54 MW will become available to retail on January 1, 2016, with the additional 24 MW on June 1, 2016. The approximately 78 MW Scherer Unit 3 resource will remain in retail rate base for 15 years (until 2031). The Commission certified the Scherer Unit 3 capacity on March 5, 2010.

On October 8, 2010, the Commission issued an order accepting Georgia Power's offer of 250 MW of Block 1 coal-fired capacity that will become available to retail on April 1, 2016 and 312 MW of Blocks 2-4 coal-fired capacity that will become available to retail on January 1, 2015. With the retirement of Branch Units 1 and 2 effective December 31, 2013 and October 1, 2013, respectively, the capacity of Block 1 and Blocks 2-4 will be reduced to 229 MW and 266 MW, respectively, and will remain in retail rate base until the end of the assets' lives. If the

Commission decertifies additional units included in the wholesale blocks described above, then the capacity of the blocks available to retail will be reduced. On March 26, 2012, the Commission issued an order certifying Block 1 and Blocks 2-4.

12.3 WHOLESALE REQUIREMENTS CONTRACTS

As of January 1, 2013, the Company no longer provides requirements service to the city of Hampton. As a result, Hampton's load (approximately 9 MW) and generation need is not integrated into the Company's resource planning process. Therefore, in the 2013 rate case, the Company will not allocate the cost to serve Hampton to the wholesale jurisdiction.

The Company is considering additional potential long-term requirements service agreements with other wholesale customers and may provide such requirements service under additional long term agreements (e.g., 20-30 years).

The requirements agreements would involve joint integrated long-term planning of wholesale and retail loads and generation resources. The wholesale customers' load and generation resources would be combined with Company load resources for planning as well as generation commitment and dispatch, thereby resulting in greater economies of scale. The Company would own (or purchase) new incremental generation required to serve its total load, including the wholesale requirements obligations. Any proposals would be subject to Commission approval of the IRP, which includes the subject requirements load.

The benefits of additional long-term requirements agreements include joint planning of generation and transmission capacity as well as economies of scale resulting in capacity and energy savings.

12.4 FLINT EMC CONTRACTS

The Company currently provides Flint EMC with 25 MW of Blocks 5 and 6 peaking capacity under an agreement that extends through December 31, 2014. The Company has also signed an agreement to provide 25 MW of Blocks 5 and 6 peaking capacity to Flint EMC from January 1, 2015 through December 31, 2024.

The Company currently provides Flint EMC with 56 MW of Scherer Unit 3 capacity under an agreement that extends through December 31, 2014 and another 24 MW of capacity under an agreement that extends through December 31, 2019. The Company has also signed an agreement to provide 56 MW of Scherer 3 capacity to Flint EMC from January 1, 2015 through December 31, 2029.

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13 – ACTION PLAN

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SECTION 13 - ACTION PLAN

The Company's action plan is as follows:

- Build, operate, and maintain the necessary generation, transmission, and distribution infrastructure to serve the growing needs of Georgia;
- Maintain long-term system planning reserve margin target of 15 percent;
- Continue to implement and develop all transmission and distribution projects necessary to ensure adequate reliability to the customers in the state of Georgia;
- Meet all environmental requirements;
- Request decertification of Plant Branch Units 3 and 4, Plant Yates Units 1-5, and Plant McManus Units 1 and 2 effective by the MATS compliance date of April 16, 2015, decertification of Plant Kraft Units 1-4 one year past the MATS compliance date (by April 16, 2016), decertification of Plant Boulevard Units 2 and 3 effective as of the date of the final order in this proceeding, and approval of expedited decertification of Plant Bowen Unit 6 by April 16, 2013 as specified in the 2013 Decertification Application;
- Request approval of a switch to natural gas as the primary fuel for Plant Yates Units 6 and 7 and Plant Gaston Units 1-4;
- Request an amendment of the decertification date specified in the Commission's final order in Docket No. 34218 for Plant Branch Unit 1 from December 31, 2013 to coincide with the decertification of Plant Branch Units 3 and 4 to enable its use as a startup boiler for Plant Branch Units 3 and 4;
- Request approval of the reclassification of the remaining net book values of Plant Branch Units 3 and 4 and Plant Boulevard Units 2 and 3 as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 31958;
- In the event the Commission does not approve the expedited decertification of Plant Bowen Unit 6, request approval of the reclassification of the remaining net book value of Plant Bowen Unit 6 as of its respective retirement date to regulatory asset account and the amortization of such regulatory asset accounts ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 31958;

- Request approval of the amortization of approximately \$38 million of Plant Branch Units 3 and 4 and approximately \$14 million of Plant Yates Units 6 and 7 environmental CWIP (which has been reclassified as a regulatory asset in accordance with the Commission's Order in Docket No. 31958) ratably over a three year period beginning January 2014;
- Request approval of the reclassification of any unusable M&S inventory balance remaining at the unit retirement dates to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 31958 for recovery over a period to be determined by the Commission in the Company's next base rate case following the unit retirements;
- Request approval of the capital and O&M costs (but not yet the recovery) of measures taken to comply with existing government-imposed environmental mandates, as set out in the Selected Supporting Information section of Technical Appendix Volume 2;
- Request approval of the capital costs the Company will incur for a portfolio of certain renewable demonstration projects (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 2;
- Request approval of a certificate of public convenience and necessity for one new DSM program, a certificate amendment for three previously certified programs, decertification of one DSM program, and approval of updated program economics for previously certified energy efficiency DSM programs as further specified in the 2013 DSM Application in Docket No. 36499;
- Continuation of the Power Credit program and the additional DSM programs detailed in Section 5.2.2, 5.2.3, 5.2.4 and 5.2.5;
- Continue to provide customer information on cost-effective energy saving options that are available in the market and provide customer specific information as required;
- Utilize Qualified Facility contracts and continue to encourage additional resources in compliance with PURPA and the Commission's Avoided Cost Order, Docket No. 4822;
- Continue to promote and expand the TOU-REO and TOU-PEV rates for residential customers;
- Continue to assess opportunities to integrate cost-effective renewable resources into the Company's supply mix;
- Take actions to enable the option for additional generating capacity in the future; and

- Implement GPASI.

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14 – ATTACHMENTS

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SECTION 14 - ATTACHMENTS

ATTACHMENT 14.1 – MAJOR MODELS USED IN IRP

Economic Model

Georgia Power's econometric forecasting models (see below) use forecasts of various key economic and demographic variables for the state of Georgia. These forecasts are developed by Moody's Analytics whose large-scale macroeconomic models produce economic and demographic forecasts for the U.S. and for the state of Georgia. Moody's Analytics models are proprietary.

Residential End-Use Energy Planning System

REEPS is an end-use model that is used to develop a long-term energy forecast of the residential sector. REEPS was developed under an EPRI contract in conjunction with Regional Economic Research, Inc.

Commercial End-Use Model

COMMEND is an end-use model that is used to develop a long-term energy forecast of the commercial sector. COMMEND was developed under an EPRI contract in conjunction with Regional Economic Research, Inc.

Industrial End-Use Forecasting Model

INFORM is an end-use model that is used to develop a long-term energy forecast of the industrial sector. INFORM was developed under an EPRI contract in conjunction with Regional Economic Research, Inc.

Econometric Forecasting Models

Various econometric forecasting models are used to estimate the relationships between economic and demographic variables and energy use and demand. These models use ordinary least squares regression techniques.

Hourly Electric Load Model (HELM)

HELM is a peak demand model that produces a forecast of peak demand using forecasted class energy, historical class load shapes and corresponding weather, and a description of typical (normal) weather.

SERVM

The Strategic Energy and Risk Valuation Model (SERVM) is a generation reliability model developed by the System in conjunction with an outside consulting firm to evaluate reliability.

SERVM is an hourly, chronological model using Monte Carlo techniques. Random numbers are used to model unplanned outages based on historical time to failure and time to repair data for the system units. The model executes beginning with hour 1 (Midnight - 1 A.M. on January 1), committing units, tracking available hydro energy, operating pumped storage units, and calling interruptible load as needed, recording the calls.

The annual processing is performed typically 100 times with the results averaged. This evaluation is performed for each weather-hydro year chosen for the study (typically the previous 50 years) and for each of six economic load forecast errors.

Useful information provided by SERVM includes:

- Expected unserved energy – the amount of energy that cannot be served due to generating capacity shortages;
- Reliability and Emergency Purchases - the amount of energy purchased from others at a cost in \$/MWh that is higher than the energy cost of a combustion turbine;
- Loss of load hours – the number of hours in which some load is not served, with statistics concerning distribution throughout the year; and
- Interruptible load – the number of times that interruptible load is called, with statistics concerning distribution throughout the year.

SERVM is a major tool providing input for numerous studies. It is used in: 1) developing the target reserve margin; 2) developing interruptible service riders; 3) developing loss of load hour tables in PRICEM; and 4) developing incremental capacity equivalent (“ICE”) factors.

PROSYM

PROSYM is used to estimate marginal energy cost for use in various models and analyses. It is also used to project marginal sulfur dioxide (“SO₂”) allowance costs. PROSYM is an hourly model that utilizes Monte Carlo techniques to randomly simulate the unit forced outages.

The useful information that can be gathered from PROSYM includes:

- Projections of marginal energy cost by hour for 20 years into the future;
- Projections of the SO₂ marginal cost of serving an additional block of load; and
- The cost effects of changing the characteristics of individual units, such as changing heat rates, station service requirements, or similar factors.

PROSYM supplies important data to many studies. It is or has been used in: (1) determining the worth of improving existing units; (2) developing the marginal energy cost for use in PRICEM and elsewhere; and (3) developing the SO₂ marginal cost for use in PRICEM.

REVREQ

REVREQ is a financial program used to convert capital expenditures into annual revenue requirements. It incorporates projections of the costs of capital, tax rates, and depreciation rates.

The useful information that can be gathered from REVREQ includes:

- Annual revenue requirements necessary to earn a return on and return of the investment;
- Net present value of revenue requirements; and
- Levelized fixed charge rates.

REVREQ provides a key calculation for numerous studies. It is or has been used in: (1) calculating revenue requirements streams for PRICEM; (2) calculating the economic carrying

cost rates and net present value of revenue requirements for many studies including, for example, for use in Strategist[®]/PROVIEW[™].

Strategist[®]/PROVIEW[™]

PROVIEW[™] is a generation planning optimization module of the Strategist[®] production cost model. It uses dynamic programming techniques to calculate the total capital and operating costs for hundreds of combinations of generating units. It calculates the minimum cost combination of units.

The useful information that can be gathered from Strategist[®]/PROVIEW[™] includes:

- Least cost combination of generating unit additions by year;
- Additional cost of generation expansion plans that are not the least-cost plan; and
- Estimates of fuel use by fuel type.

PROVIEW[™] is the basis of the benchmark plan. Sensitivity analyses performed through Strategist[®]/PROVIEW[™] provide information for developing a combination of generating units that will provide a good combination of flexibility, risk reduction, and other considerations. Strategist[®] is used to integrate the supply-side options and the demand-side programs to produce the IRP. Strategist[®]/PROVIEW[™] are also used to evaluate bids received in the competitive bidding process.

PRICEM

The Profitability Reliability Incremental Cost Evaluation Model (“PRICEM”) is a spreadsheet-based marginal cost model designed to estimate a change in revenue requirements and other effects attributable to changes in loads and/or revenues. PRICEM was developed by the System and takes data from other major models, combining them in a single spreadsheet to provide for quick, yet relatively detailed, evaluations of options. Data inputs are consistent with inputs to Strategist[®]/PROVIEW[™] and as such are taken from: (1) revenue requirements streams from REVREQ, (2) marginal energy cost from PROSYM, (3) ICE factors from SERVVM, and (4) Generation Technology Data Book assumptions.

PRICEM models the year with 864 load points and uses the peaker method, a technique allowing the total of generating capacity cost and energy cost to be estimated with peaking capacity and marginal energy cost. The peaker method allows for quick screening of many alternatives. Useful information that can be gathered from PRICEM includes:

- RIM - A net present value calculation of the total benefits and total costs over the life of the program; and
- Predictions of the amount of generating capacity needed to maintain System reliability after a change in interruptible or firm loads.

EnerSim

EnerSim is Southern Company's proprietary hourly building energy simulation model. It has been certified and approved by the U.S. Department of Energy ("DOE") and is listed on their website as "Qualified Software". EnerSim predicts hourly energy consumption in buildings based on construction characteristics, insulation, occupancy, orientation, local weather, and equipment. RateSim, the rate analysis tool within EnerSim, uses the hourly energy data to estimate monthly energy bills. Finally, the hourly energy data, or loadshape, is used in PRICEM along with the energy bills from RateSim.

EnerSim is used to calculate the building energy load profiles of weather-sensitive energy efficiency measures, such as heating and cooling equipment upgrades, and insulation and weatherization improvements.

GenVal

GenVal is a model that is used to project the economic dispatch of a generating unit within the Southern Company fleet of resources. It utilizes hourly marginal costs from PROSYM, as well as the operating characteristics of the generating unit to be analyzed. The useful information that can be gathered from GenVal includes the system production cost impacts due to the inclusion of the generating unit within the Southern Company generation fleet.

ATTACHMENT 14.2 – TECHNOLOGY SCREENING

Table 14.2.1 TECHNOLOGY SCREENING

Technology	Description	Status
1. Subcritical Pulverized Coal (Conventional Pulverized Coal)	This technology is mature with a large number of units on the system. New units would include the latest emission control systems to ensure compliance with all applicable environmental regulations and permit requirements.	RETAINED for further screening.
2. Supercritical Pulverized Coal	This technology is mature with several units on the system. Environmental performance would be similar to subcritical pulverized coal.	RETAINED for further screening.
3. Ultrasupercritical Pulverized Coal (USC)	This technology involves the evolution of coal-fueled generation to slightly higher steam pressures and temperatures than supercritical conditions to attain higher thermal efficiency. It also includes design for flexible operation, including the maintenance of higher efficiencies at partial loads. Many of these advanced features will gradually be incorporated into new base load coal-fueled capacity as they are made available through U.S. and international research efforts. The environmental performance would be similar to subcritical pulverized coal. Material capabilities limit the practical design of this unit, though currently there are operating designs that exceed supercritical limits (main steam conditions around 3600psia and 1100F).	RETAINED for further screening.
4. Advanced Ultrasupercritical Pulverized Coal (AUSC)	This technology represents the targeted design of current US and international USC research and embodies coal-fueled generation to steam conditions higher than that achieved by existing ultrasupercritical pulverized coal technology for even higher thermal efficiency (steam conditions approaching 5000psia and 1400F). The environmental performance would be similar to subcritical pulverized coal. This technology is nearing demonstration phases but requires more materials development to be completed.	Dropped from further screening due to current level of development.
5. Atmospheric Fluidized Bed Combustion (AFBC)	This technology includes both bubbling bed designs and circulating bed designs. AFBC technologies have the potential for sulfur removal without add-on flue gas scrubbers.	Dropped from further screening due to economic reasons.

Technology	Description	Status
	AFBC is currently better suited to industrial cogeneration and is probably the technology of choice for low grade, high ash coals and is typically limited to 300MW in size. When combined with future supercritical materials, AFBC economics may improve.	
6. Pressurized Fluidized Bed Combustion (PFBC)	These plants could be produced as modular factory assembled units, but there are reliability concerns with particulate removal at high temperature and pressure, possible corrosion and erosion in the bed, and uncertainties with the cost of large pressure vessels. Vendors have recently stopped marketing and development efforts of PFBC.	Dropped due to lack of commercial development.
7. Topping PFBC	In this concept, the coal feed is partially gasified to produce a low-Btu fuel gas, and the residual char is burned in a PFBC combustor. The flue gas is used as the oxidant to burn the fuel gas and raise the gas turbine inlet temperature to 2,750° F. Vendors have recently stopped marketing and development efforts of TPFBC.	Dropped due to lack of commercial development.
8. Oxygen-Blown IGCC	This concept has potential for modularity, staged construction, and improved efficiency and environmental performance over pulverized coal-firing. Capital cost is an important concern of the technology and the use of advanced turbines is necessary for further efficiency improvement. Southern Company has constructed a power system test facility in conjunction with DOE to refine IGCC. Based on most current studies of CO ₂ capture for a coal-fueled power plant, IGCC has a cost advantage over pulverized coal because the CO ₂ in the gas stream is much more concentrated and at a higher pressure.	RETAINED for further screening.
9. Air-Blown Integrated Coal Gasification Combined Cycle	This technology is based on an advanced concept using an air blown transport gasifier and associated combustor. Air blown IGCC offers lower capital costs and higher efficiency compared to oxygen blown IGCC. Commercial deployment is underway at Plant Ratcliffe in Mississippi and in China. Further improvements to the technology are being evaluated at the NCCC facility operated at	RETAINED for further screening.

Technology	Description	Status
	Southern Company in conjunction with the DOE that have the potential for lower capital cost and higher efficiency.	
10. Non-Integrated Coal Gasification Combined Cycle	This concept holds promise for modularity and staged construction. Capital cost is an important concern of the technology and the development of advanced turbines is necessary for further efficiency improvement.	Dropped from further screening because the integrated version would be more cost-effective and efficient.
11. Integrated Gasification Fuel Cell Combined Cycle	This is a future concept that depends on the development of advanced fuel cells that would be substituted for combustion turbines in the gasification combined cycle plant to provide high efficiency and extremely low environmental emissions. The commercialization of this concept is still uncertain given its dependence on the development of several advanced technology concepts.	Dropped from further screening due to its low level of development and high degree of uncertainty with cost projections.
12. Magnetohydrodynamics (MHD)	MHD appeal is high efficiency and inherent SO ₂ , nitrogen oxide (“NO _x ”), and particulate control. The key developmental component is the MHD generator, in which a conducting exhaust gas from the combustion of coal along with seed material is passed through a magnetic field to produce DC electricity. The bottoming cycle is a conventional boiler and steam turbine. However, progress with MHD remains slow to stagnant and conceptual estimates indicate very high cost.	Dropped from further screening due to the level of development and cost uncertainties.
13. CT (Conventional/Advanced)	Many conventional units exist on the system. The technology is mature, but advanced designs offer even higher turbine inlet temperatures for improved efficiencies. The increasing turbine temperatures will open new reliability questions. CTs can be applied as peaking capacity and in combined cycle plants using natural gas or oil. Advancements are being closely monitored. State-of-the-art combustion NO _x control systems will be incorporated in the designs.	RETAINED for further screening.
14. CC (Conventional/Advanced)	Units are in operation on the system and the technology is mature. Future designs using more state-of-the-art CTs will offer better	RETAINED for further screening.

Technology	Description	Status
	<p>economies (see CTs above). Vendors are now offering new CT designs with increased turbine inlet temperatures for improved CC efficiencies. Each of the major OEMs now offer packaged CC plants, based on advanced gas turbine technology, which offer greater thermal efficiencies and increased operational flexibility compared to conventional units. State-of-the-art NOx control systems will be incorporated for environmental compliance. A number of advanced CT-based cycles such as the CHAT, HAI, and Kalina cycles have the potential for higher thermal efficiencies, however they have not been commercially demonstrated.</p>	
<p>15. Phosphoric Acid Fuel Cells</p>	<p>Phosphoric acid electrolyte systems using natural gas are the most mature fuel cell technology and as such have the most extensive track record for operational experience. Recent industry activity from UTC Power suggests renewed commitment to PAFC technology. This system has shown improvements as well as a reduction in cost. Attractive features include modular construction, low environmental impact, siting flexibility, and high efficiencies at small sizes.</p>	<p>RETAINED for further screening.</p>
<p>16. Advanced High Temperature Fuel Cells - Molten Carbonate Fuel Cell (MCFC) and Solid Oxide Fuel Cell (SOFC)</p>	<p>Fuel cells using molten carbonate or solid oxide electrolyte may be more attractive than the phosphoric acid or PEM fuel cell. Since these fuel cells are operated at high temperatures (600-1000°C), the incentives include higher efficiencies; more flexible and simplified fuel processing and use of inexpensive catalyst. Also, by-producing heat at these high temperatures, there are more applications than phosphoric acid systems, such as cogeneration and incorporation of a bottoming cycle. These fuel cells also have potential for use with coal gasification in integrated gasification fuel cell power plants. About 40 units are in the field with capacities ranging from 250kW to 1 MW. Cost, material selection under high temperature operation, and cell durability remain important issues. Fuel Cell Energy is the only commercializer in the US for MCFC</p>	<p>RETAINED for further screening.</p>

Technology	Description	Status
	<p>technology. SOFC is also moving up on the technology maturity curve, but they are at least a couple years behind the MCFC. However, their long term cost projection is lower than that of MCFC. Environmental characteristics are expected to be excellent for all fuel cell technologies.</p>	
17. Fuel Cell CC (FCCC)	<p>See Advanced High Temperature Fuel Cells. By-product heat from MCFC or SOFC can be used in bottoming cycles to produce additional power. Siemens demonstrated a pressurized 220 KW SOFC/MT hybrid in Ca. and achieved 52 percent efficiency even though the system was not optimized. FuelCell Energy is also testing an atmospheric MCFC/MT hybrid system. DOE Vision 21 power plant highlights such system at efficiency of 60-70 percent (80-90 percent with thermal) with 0 air pollutants and CO2 (with sequestration) by 2015. The costs from such a system should be at par with market rate.</p>	<p>RETAINED for further screening.</p>
18. Reciprocating Engines / Microturbines	<p>Diesel or gas fired generators and microturbines could potentially have economics competitive with combustion turbines at very low capacity factors and for dispersed applications. Microturbines are emerging in niche markets around the world, mostly in co-generation applications. The current trend is towards larger systems with heat recovery and/or chillers. There are environmental concerns due to relatively high emission rates for certain pollutants when burning diesel fuel.</p>	<p>Dropped from further screening since the applications for dispersed generation are very site-and customer-specific.</p>
19. Pumped Storage Hydroelectric	<p>Pumped hydroelectric energy storage is a large, mature, and commercial utility-scale technology used at many locations in the United States and around the world. Southern Company currently applies this technology on its system. This application has the highest capacity of the energy storage technologies assessed, since its size is limited only by the size of the available upper reservoir. Facilities of this type must deal with environmental issues related to land use and the availability of the water source.</p>	<p>RETAINED for further screening.</p>
20. Underground Pumped	Underground pumped storage hydro could avert	Dropped from

Technology	Description	Status
Storage Hydroelectric (UPH)	the environmental and licensing problems of conventional above ground facilities. The high excavation costs and long lead times of UPH significantly reduce its attractiveness. A 1000 MW underground pumped storage generation facility is being developed in Wiscasset, Maine.	further screening due to high cost and stage of technology development.
21. Compressed Air Energy Storage (CAES)	CAES plant hardware is commercially available. The first CAES (290 MW) plant was constructed in Germany in 1978. A 100 MW plant was constructed by Alabama Electric Cooperative and began commercial operation in June 1991 and is an integral part of AEC dispatch. There are several design configurations for new advanced CAES plants including combustion turbine based and adiabatic cycles using thermal energy recovery and storage. Although subsystems have been proven, the advanced cycles have yet to be demonstrated as an integrated system. CAES cycles can utilize either above ground (low MW) or below ground (high MW) energy storage options. The potential for large scale energy storage depends on suitable geology for constructing the air storage reservoir. The preferred geology for Southern Company would be salt dome sites in Mississippi and Alabama. CAES has the potential for better local environmental characteristics than pumped hydro. Brine disposal may be an environmental concern during reservoir construction.	RETAINED for further screening.
22. Lead/Acid and Advanced Batteries (Load Leveling, UPS)	Lead/acid technology is mature, but life at elevated operating temperature with heavy duty cycles is of concern. Advanced batteries are being developed to achieve higher energy and/or power density, higher reliability, lower maintenance and longer life at a cost that can be competitive to conventional lead acid batteries. Potential applications include load management/peak shaving applications to defer the power plant construction for peaking capacity and backup power for T&D substations. Environmental impact on the local area is expected to be very low when the charging source is not considered.	RETAINED for further screening. (advanced battery)
23. Flywheel Energy	Flywheels store mechanical energy, with the	Dropped from

Technology	Description	Status
Storage	<p>amount dependent on the inertia and rotational speed of the flywheel. Southern Company has demonstrated flywheel feasibility in short term ride-through for power quality (PQ) applications with very good success, but systems for high energy storage applications for peak shaving and/or load leveling are still undeveloped. Acceptable total system costs have been achieved with the PQ units and the ability to integrate the mechanical and power electronic components has been demonstrated. Monitoring of activity in the MW class systems continue and further cost reductions for composite materials, magnetic bearings, and power electronics will improve the chances for future electrical energy storage applications.</p>	<p>further screening due to the early status of development and better suitability for dispersed generation applications.</p>
24. Nuclear Advanced Light Water Reactor – Evolutionary	<p>These plants are similar in design to Hatch, Farley and Vogtle but incorporate many evolutionary improvements in areas such as controls, systems, materials, construction techniques, and a streamlined regulatory approval process. Plants in this category include the Advanced Boiling Water Reactor (“ABWR”) by GE and Toshiba, Advanced Pressurized Water Reactor (“APWR”) by Mitsubishi and the European Pressurized Water Reactor (“EPR”) by Areva. ABWRs are in operation in Japan, and have been considered for several sites in the US. The APWR has been discussed for several US sites, but no license applications have been submitted to date. The EPR design is being built in Europe, and a modified version has been submitted for certification in the US. The evolutionary designs have the same environmental characteristics as the current fleet of light water reactors.</p>	<p>RETAINED for further screening.</p>
25. Nuclear Advanced Light Water Reactor – Passive	<p>Southern Company has made a commitment to this technology as evidenced by the ongoing construction of two AP1000 (1000 MW) nuclear units at the Vogtle site for commercial operation in 2017 and 2018. In addition to the Westinghouse AP1000 design, this category includes the ESBWR, a passive BWR design under development by GE. The ESBWR</p>	<p>RETAINED for further screening.</p>

Technology	Description	Status
	design is not yet certified by the NRC. Westinghouse is also considering development of a larger passive plant, possibly an AP1600 (1600 MW). The current passive designs have the same environmental characteristics as the current fleet of light water reactors.	
26. Nuclear Advanced Light Water Reactor – Modular	The economics of the smaller advanced modular reactor designs, such as the B&W mPower (approximately 125 MW) are unclear. Additionally, these designs are years behind the evolutionary and passive plants in terms of both design development and licensing. They are expected to have the same environmental characteristics as other nuclear options.	Dropped from further screening due to development status.
27. Solar Thermal Parabolic Trough	Solar technologies based on focusing the sun’s energy to heat a working fluid work most effectively in direct sunlight. Diffuse solar insolation due to clouds and haze in the Southeast reduces the value of most solar thermal applications, and the high capital cost and large land area requirements are significant concerns. The technology has good environmental characteristics. One potential application of this technology is to use the steam that can be generated from this technology to augment the steam generated from a conventional fossil power plant, or to augment thermal loads in processes such as post-combustion carbon capture, giving a lower-cost method of utilizing solar energy to power.	RETAINED for further screening.
28. Solar PV	Cost has dropped significantly in recent years, getting closer to being competitive on large scale with retail rates. Research continues to increase efficiency and reduce cost. Issues include the site specific solar insolation resource and large land area requirements. There are some limits to applicability in the southeastern U.S. Breakthroughs in PV technology could make this a very attractive alternative. The technology has excellent environmental aspects.	RETAINED for further screening.
29. Wind Power	Available wind resources in the southeastern U.S. are not adequate to currently support significant utility scale use of this technology.	RETAINED for further screening.

Technology	Description	Status
	Advancing wind turbine technologies could increase potential.	
30. Municipal Solid Waste (“MSW”)	MSW generation has been used in some locales where landfills are too expensive or environmentally unacceptable. Thus, it has some potential but is highly site-specific and limited in ultimate quantity.	Dropped from further screening due to limited interest and high level of environmental concern.
31. Dedicated Biomass (wood, etc.)	Biomass (wood, wood waste, agricultural residues) is widely available in the Southeast. A dedicated biomass-fired power plant of 50MW to 100MW in size is feasible. Major consideration is obtaining fuel under a long-term contract at a reasonable (and low) price. The plant may rely on gasification of biomass, followed by a CT to convert the gas to electricity. Raw biomass tends to have a high transportation cost, due to its low energy-density in raw form. This places an upper limit on the size of a dedicated biomass-consuming power plant.	RETAINED for further screening.
32. Co-fired Biomass or Wood Waste	Co-firing of switchgrass and wood waste has been demonstrated at several system power stations. Co-firing of these materials is now routine in AL and MS for green power pricing programs. Co-firing at up to 10 percent is probably the upper limit with traditional woody biomass. Co-firing at higher levels with advanced fuels such as pellets and torrefied wood is possible, but is potentially detrimental to SCR emission reduction system catalysts.	RETAINED for further screening. (refer to technology 1).
33. Landfill Gas	Capped landfills produce methane gas through anaerobic digestion of the landfill contents. The gas has about half the energy of natural gas per cubic foot and can be burned in engines or co-fired in natural gas boilers or turbines. Many environmental advantages with possible economic viability are present. A single large landfill may provide gas for 7MW max.	RETAINED for further screening.
34. Geothermal	Geothermal resources in the southeastern U.S. are not adequate to support utility scale of this technology. Technologies are being monitored on a research level for potential niche applications.	Dropped from further screening due to limited applicability in Georgia Power’s

Technology	Description	Status
		and Southern Company's territory.
35. Solar Stirling Dish	The Dish Stirling engine operates as an externally heated piston-driven prime mover. In a solar Stirling dish system, a dish is used to capture and focus sunlight to provide heat for the Stirling engine. As with the parabolic trough and other reflector systems, diffuse solar insolation due to clouds and haze in the Southeast greatly reduces the effectiveness and value of solar Stirling dish. This technology has good environmental characteristics, but applicability is very limited in the southeastern U.S.	Dropped due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.
36. Solar Central Receiver Technology	This technology is commonly referred to as a "power tower", where an array of mirrors is focused on a specific area on a tower that contains a receiver (boiler) where steam is made directly. It works most effectively in direct sunlight. Diffuse solar insolation due to clouds and haze in the Southeast reduces its value, and the high capital cost and large land area requirements are significant concerns. This technology has good environmental characteristics.	Dropped due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.
37. Compact Linear Fresnel Reflector	Rows of solar collectors reflect solar radiation onto a linear receiver above the solar field in which pressurized water is converted into steam. It works most effectively in direct sunlight. Diffuse solar insolation due to clouds and haze in the Southeast reduces its value, and the high capital cost and large land area requirements are significant concerns. This technology exhibits good environmental characteristics.	Dropped due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.
38. Ocean Energy & Hydrokinetic Generation	Ocean energy and hydrokinetic generation includes power generation from waves, ocean current, tides, and river current. Specific research has begun to be conducted in these areas defining the resources and developing technologies that can utilize these resources. They have the potential to negatively affect estuarine environments.	RETAINED for further screening (hydrokinetic only). Ocean energy dropped due to cost, level of development, lack of sites, and environmental

Technology	Description	Status
		considerations.
39. Ocean Thermal Generation	The temperature difference between surface and deep ocean waters can be used to drive an ammonia or other low-temperature power cycle to produce power. In most situations, tropical locations with deep ocean near shore are sought. There are environmental concerns with releasing cold bottom water at the ocean surface and with the potential for ammonia release.	Dropped due to cost uncertainties, level of development, lack of good sites in Georgia Power's and Southern Company's territory, as well as potential environmental considerations.

Table 14.2.2 Candidate Technologies

<p><u>COAL-FUELED</u></p> <p>Subcritical Pulverized Coal (2400 psi) Supercritical Pulverized Coal (3500 psi) Advanced Ultrasupercritical Pulverized Coal Ultrasupercritical Pulverized Coal Atmospheric Fluidized Bed Combustion Bubbling Bed Circulating Bed Pressurized Fluidized Bed Combustion Bubbling Bed Circulating Bed Advanced Topping Circulating FBC Integrated Gasification Combined Cycle Oxygen-Blown Advanced Air-Blown Non-Integrated Coal Gasification Combined Cycle Integrated Gasification Fuel Cell Combined Cycle Magnetohydrodynamics (MHD)</p> <p><u>LIQUID/GAS FUELED</u></p> <p>Combustion Turbine Conventional Combustion Turbine Advanced Aeroderivative – Simple Cycle</p> <p>Combined Cycle Conventional Heavy Oil-fired Combined Cycle Advanced G/H technologies Inlet Air Chilling Kalina Cycle Cascaded Humidified Adv. Turbine (CHAT) Humidified Air Injection (HAI)</p>	<p><u>LIQUID/GAS FUELED (CONTINUED)</u></p> <p>Phosphoric Acid Fuel Cell Advanced Fuel Cells Fuel Cell Combined Cycle Diesel Generator</p> <p><u>ENERGY STORAGE</u></p> <p>Pumped Hydro Underground Pumped Hydro Lead Acid Battery Advanced Battery Flywheel Compressed Air Energy Storage</p> <p><u>NUCLEAR</u></p> <p>Advanced LWR Evolutionary Advanced LWR Passive Advanced LWR Modular</p> <p><u>RENEWABLES</u></p> <p>Solar Thermal Parabolic Trough Photovoltaics Wind Power Municipal Solid Waste Biomass (Wood, etc.) (Dedicated/co-firing) Landfill gas Geothermal Solar Dish Stirling Solar Central Receiver Compact Linear Fresnel Reflector Ocean Wave and Hydrokinetics Ocean Thermal Generation</p>
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Table 14.2.3 Technologies Selected for Further Screening

COAL-FUELED:	ENERGY STORAGE:
Conv. Pulverized Coal (Subcritical)	Pumped Hydro
Conv. Pulverized Coal (Supercritical)	Compressed Air Energy Storage
Ultrasupercritical Pulverized Coal	Advanced Battery
Oxygen-Blown IGCC	
Air-Blown IGCC	NUCLEAR:
	Advanced LWR - Evolutionary
GAS-FUELED:	Advanced LWR - Passive
Combustion Turbine Conventional	
Combustion Turbine Advanced	RENEWABLES:
Combined Cycle Conventional	Solar Thermal Parabolic Trough
Combined Cycle Advanced	Photovoltaics
Phosphoric Acid Fuel Cell	Wind Power
Advanced Fuel Cell	Dedicated Biomass
FCCC	Co-fired Biomass/Wood Waste
	Landfill Gas
	Hydrokinetic

ATTACHMENT 14.3 – SUMMARY OF THE SYSTEM POOLING ARRANGEMENT

Introduction

Georgia Power Company is a member of the Southern Electric System, which consists of the Operating Companies. The Operating Companies function as a single, integrated public-utility system through adherence to the Southern Company System Intercompany Interchange Contract (“IIC”), an agreement on file with the FERC. SCS acts as agent for the Operating Companies in the administration of the IIC. The term of the IIC provides for the agreement to continue in effect from year-to-year after the effective date subject to termination at any time by mutual agreement of all the Operating Companies or subject to termination by an individual Operating Company by giving five years advance written notice.

The IIC provides a framework whereby the generating resources of the Operating Companies are operated in a coordinated and integrated fashion to economically serve their aggregate firm obligations, as well as to engage in shorter term transactions in the wholesale markets. Using traditional concepts of economic dispatch, the Pool deploys available generation to satisfy the aggregate obligations of the system at any given time in a reliable and economic fashion. The IIC also provides for coordinated planning between the Operating Companies and for the sharing of temporary surpluses and deficits of capacity. The IIC ensures that the after-the-fact accounting associated with joint system dispatch (energy) and reserve sharing (capacity) is handled in accordance with the principles set forth in that agreement. It should be noted that the coordinated planning process for the four traditional (retail) companies (Mississippi Power, Alabama Power, Georgia Power and Gulf Power) has been functionally separated from the planning process for Southern Power in the latest IIC. This functional separation does not change the manner in which the other four Operating Companies have traditionally conducted coordinated planning.

Relationship of the Operating Companies under the IIC

The Southern Company Pool is a coordinated Pool, not a centralized Pool. Although the generating facilities of each Operating Company are committed to a centralized economic dispatch, each individual Operating Company retains the right and the responsibility for

providing the generation and transmission facilities necessary to meet the requirements of its customers. Each Operating Company has its own management that reports to its own board of directors, with the management and the board of directors of each Operating Company being directly responsible for making the decisions that affect that Operating Company and its customers. They are also responsible for working with local regulators and adhering to the requirements of state law.

Accordingly, each Operating Company has its own distinct characteristics in regard to types of generation and load. For example, Alabama Power, Georgia Power and Southern Power bring hydroelectric and nuclear generating capacity to the Pool, while the other Operating Companies do not. Similarly, the load characteristics of the Operating Companies vary due to the types of customers each brings to the Pool. The differing economies within each Operating Company territory and/or customer base lead to different load growth rates and load shapes for each Operating Company.

The IIC provides for an Operating Committee that consists of one representative of each Operating Company and SCS, with the SCS representative acting as a non-voting Chairman. The functional separation of certain activities of Southern Power restricts the participation of its Operating Committee member in some matters (such as discussions and recommendations involving the coordinated planning of the four retail Operating Companies). A unanimous vote of the five Operating Company members is required in order to change the IIC.

Interconnections

The Operating Companies are interconnected with 12 non-associated utilities through 61 different transmission facilities. These transmission lines are operated at voltages of 46 kV, 69 kV, 115 kV, 161 kV, 230 kV and 500 kV, and include facilities that are operated normally open. The non-associated utilities with which the SES is interconnected are shown in Table 14.3.1 below.

Table 14.3.1 – Non-Associated Utilities

Florida Power & Light Company	Progress Energy - Florida (Duke Energy)
JEA	City of Tallahassee
Duke Energy Corporation (Carolinas)	South Carolina Electric & Gas Company
Tennessee Valley Authority	South Carolina Public Service Authority
Entergy Corporation	Crisp County Power Commission
PowerSouth Energy Cooperative	South Mississippi Electric Power Association.

Basic Principles of the IIC

The basic principles of the IIC can be summarized as follows.

1. Each Operating Company submits its load and generation to the Pool for joint commitment and economic dispatch.
2. Energy Principles
 - a. Each Operating Company retains its lowest cost resources to serve its customers.
 - b. An Operating Company’s excess energy is then made available to the other Operating Companies to serve their customers.
 - c. An Operating Company is entitled to buy energy from the Pool if the cost is lower than energy from its own resources.
 - d. Energy in excess of that necessary to serve the Operating Companies’ customers is marketed by the Pool to the wholesale markets.
3. The IIC provides for coordinated planning among the retail Operating Companies and for the sharing among all Operating Companies of temporary surpluses and deficits of capacity.
4. Under the IIC, each Operating Company shares in the benefits and pays its share of the costs resulting from their coordinated operations.

Participation in the Southern Company Pool provides benefits to the Operating Companies and to their customers. This not only enhances GPC's ability to provide reliable, low-cost electric service to its customers but also to achieve economies of scale in any required investments. Benefits of Pool participation include:

- (a) Staggering construction of new generating facilities so that each retail Operating Company can construct and install the optimum sized generating facilities while utilizing economies of scale;
- (b) Sharing temporary surpluses and deficits of generating capacity that can arise as a result of coordinated planning or other circumstances (e.g., staggered construction schedules, variations in load patterns, load forecast uncertainties, etc.);
- (c) Coordinating scheduled maintenance to provide greater flexibility, including major maintenance requiring relatively long unit outages, as well as mitigating the cost impact (to customers) of these required outages;
- (d) Carrying a lower generation planning reserve margin (due primarily to system load diversity), which enables each Operating Company to have a lower investment in generating resources;
- (e) Providing reliable service with shared operating reserve requirements (which puts downward pressure on fuel costs);
- (f) Access to lower cost energy from other Operating Companies;
- (g) Enhanced reliability of electric service through the use of transmission interconnections to provide backup service in case of emergencies as well as providing the ability to import lower cost energy when available; and,
- (h) Acting as a Pool (instead of individual Operating Companies) to identify shorter term purchase and sale opportunities in the wholesale markets that may be available from time to time.

Basic Operation of the IIC

The concept of economic dispatch, which seeks to minimize the total system production cost, is one of the major benefits of the Pool. The generating assets of all the Operating Companies in the Pool are committed and dispatched as a common system without regard to the ownership of each generating facility. Subject to operational constraints and reliability considerations, the lowest cost generation assets are dispatched during each hour to meet the total needs of the customers of all the Operating Companies. The goal of this process is to ensure that the lowest cost energy is produced every hour. It also should be noted that each Operating Company retains its lowest cost generation to serve that Operating Company's customers.

The Pool also interfaces with the wholesale markets on behalf of the Operating Companies for both sales and purchases. When the Pool has excess power available, it will pursue wholesale sales opportunities for which there is a reasonable expectation that the transaction will result in positive net margin for the Operating Companies. There are two primary reasons for the Pool to seek purchase opportunities: (1) economics; and (2) reliability. The Pool will pursue purchase opportunities from the wholesale markets if such purchases are expected to be more economical than system resources (again, subject to operational constraints and system reliability). In the event the Pool experiences reliability challenges, then the Pool may seek purchases in response to such operating conditions.

Reserve Sharing

As noted in the introduction, the IIC contains capacity provisions, commonly referred to as "reserve sharing", that provide for a sharing of temporary generating capacity surpluses and deficits that are a result of coordinated planning or other circumstances. As participants in the coordinated operation of the integrated electric system, each Operating Company enjoys the same level of service reliability. In any given month, however, one or more Operating Companies will have a temporary surplus or deficit of capacity relative to the overall level of actual system reserves. Consistent with the goal of sharing in the benefits and burdens of the coordinated and integrated electric system, the reserve sharing provisions of the IIC provide for the equitable allocation of such temporary surplus or deficit capacity. The resulting purchase and sale of capacity is transacted on a monthly basis.

Reserve sharing is determined by comparing each Operating Company's load responsibility with its respective capacity resources recognized through the coordinated planning process. The Operating Companies must own or purchase sufficient capacity (including capacity available for load service and that which is unavailable due to forced outage, partial outage, and maintenance outage) needed to reliably serve their respective load responsibilities. Capacity above that amount is considered reserve capacity, and each Operating Company is responsible for a portion of such reserve capacity based upon historical peak load ratios. If an Operating Company's reserve capacity is less than its reserve responsibility, that Operating Company will make reserve sharing payments under the IIC for the month.

Each Operating Company develops an annual charge (payments are based on monthly capacity worth) based upon the cost of its most recently installed or purchased peaking resource(s). The Operating Companies that are "selling" capacity to the Pool will receive a payment from the Pool based upon their respective capacity rates. The Operating Companies that are "buying" capacity from the Pool will make payments to the Pool based upon the weighted average of the capacity rates of the "selling" Operating Companies. In this way, all the buying Operating Companies pay the same composite cost in a given month for reserve sharing purposes. By definition, the amount by which one or more Operating Companies are "short" (make payments) will be equal to the amount by which one or more Operating Companies are "long" (receive payments).

Energy Transactions

Energy transactions within the Pool are accounted for on an hour-to-hour basis, with the accounting occurring after-the-fact utilizing the actual flows among the operating companies.

The actual real-time operation of the system is based upon the concept of economic energy dispatch, which through on-line computer control assures that available generation is dispatched so as to choose the most economical generation available to serve the total System obligation at any given time. An adequate set of lowest-cost generating resources is committed in advance to meet the total System obligation, with due regard for generation requirements associated with service area protection, voltage control, unit protection, and other operating limitations considerations.

For billing purposes under the IIC, each operating company is deemed to have retained its lowest-cost energy resources (most notably hydro and nuclear) to serve its own territorial customers, plus whichever of its resources that may have been operating outside of economic dispatch for purposes of service area protection or voltage control. To the extent an operating company's generation exceeds its own load obligations, that energy is sold to the pool under the IIC. If an operating company's generation is not equal to or greater than its own load obligations, the difference is purchased from the pool. The energy rate for energy sold to or purchased from the pool by each operating company is referred to as the Associated Interchange Energy Rate and represents the incremental System cost of serving the Operating Companies' aggregate firm obligations. Under the IIC, the determination of which operating companies are buying from and which are selling to the pool is made on an hourly basis, and an invoice that accounts for these energy transactions is rendered monthly.

Peak-Period Load Ratios

Peak-Period Load Ratios are utilized in the allocation of certain energy and capacity transactions by the Pool with non-associated systems, hydro regulation energy losses, increases in cost due to hydro regulation, and other allocations provided for in the IIC and the Manual to the IIC.

The Peak-Period Load Ratios for each contract year are based upon the prior year's actual peak-period energy in the months of June, July, and August for each Operating Company. The peak period is defined to be the 14 hours between 7:00 a.m. and 9:00 p.m. of each weekday, excluding holidays. The System peak-period energy is equal to the sum of all the Operating Companies' peak-period energy.

The Peak-Period Load Ratios are determined by dividing each Operating Company's summation of the June, July, and August actual weekday peak-period energy loads by the total System June, July and August actual weekday peak-period energy loads.

ATTACHMENT 14.4 – RESEARCH ACTIVITIES

Research & Environmental Affairs

Georgia Power as a member of the System is involved in a wide range of research activities and programs. These activities can be categorized into five major strategic areas: Environmental Issues, Energy Supply Technology, Energy End Use Research, Transmission and Distribution and Research & Environmental Management. Each of these areas is composed of a number of groups of programs.

Environmental Issues

Environmental Legislation and Regulation Program – Provide scientific and economic analyses of policy options, legislation, and international initiatives as well as recommendations for actions to achieve environmental goals.

Regulatory Implementation Program – Provide analyses necessary to minimize the cost of complying with environmental requirements.

Compliance Strategies and Permitting Program – Develop, maintain and coordinate the implementation of system-wide, cost effective environmental and compliance strategies and provide direct technical support and coordination of all environmental activities. This program seeks environmental permits that clearly meet the intent of regulations and carry out Southern Company's environmental commitment, while balancing operating flexibility, schedules, and cost.

Environmental Sciences Research Program – Develop information related to environmental effects of the Company's operations to support Company efforts to make sound science available for environmental regulatory policy decisions.

Environmental Stewardship Program – Develop, implement, and coordinate a comprehensive, integrated environmental stewardship program and facilitate transparent and productive engagement on environmental issues with internal and external stakeholders.

Energy Supply Technology

Emissions Control Program – Develop technologies and provide strategic research and development to facilitate both short and long term environmental compliance decisions.

National Carbon Capture Center - Support technology developers in accelerating development of technically and economically viable CO₂ capture technologies for enabling coal-based power generation to remain a key contributor to providing affordable, reliable, and clean power generation and continue optimization of advanced coal-based power generation technologies.

Advanced Energy Systems - Evaluate and develop new concepts in energy systems; support new technological advances in the areas of energy production, use, and supply; and promote a more robust relationship with key stakeholders to identify unconventional and future opportunities for more valuable integrated energy systems.

Carbon Capture, Utilization, and Storage - Support the development of economic CO₂ capture technology; demonstrate secure CO₂ storage within the Company territory, engage in stakeholder outreach to ensure support for technology deployment, and promote the development of new systems and tools, modeling capabilities, and business models to support commercial deployment.

Simple, Combined, and Advanced Cycle Power Research Program - Maximize gas turbine fleet availability and performance; analyze, develop, and demonstrate emerging advanced natural gas generation concepts for retrofit or greenfield applications, and provide generation technology assessment for system planning support.

Plant and Fuels Enhancements Program - Research, develop, and demonstrate advanced technologies that reduce existing plant operating costs or improve reliability; provide solutions to highly specialized plant problems that have been screened with regard to risk, probability of

success and rate of return and analyze, develop, and demonstrate emerging advanced generation concepts for greenfield or retrofit applications.

Renewable Energy Program - Evaluate current biomass, wind, solar, and other central station and distributed generation technologies for renewable energy production; provide technical, economic, and environmental research to evaluate, develop, and demonstrate promising future renewable technologies; and determine the lowest cost approaches to central station and distributed generation renewable technologies.

Energy End Use Research

Industrial Energy Efficiency Program – Bring proven new industrial electrotechnologies, or existing technologies with new applications to the market.

Building Energy Efficiency Program - Identify, assess, and demonstrate new energy efficient technologies and software products for application in building design, energy-related heating, ventilating, and air conditioning (HVAC), water heating, lighting, appliance, and building structure.

Electric Transportation Program – Use internal and external research and development resources to support technology evaluation, testing, and demonstration of non-road technologies and electric drive vehicles.

Power Quality (“PQ”) Program - Identify, assess, and demonstrate new PQ technologies that will increase customer productivity by providing for point-of-use enhanced PQ and assisting personnel with troubleshooting and analysis. This program will evaluate other end-use technologies and their PQ impacts to the power delivery system.

Transmission and Distribution

Transmission Lines Program - Deploy and develop tools, technology, and work practices in order to further improve the effectiveness of the Company’s transmission system.

Substations Program - Develop tools and technology to ensure the company’s substations are reliable, secure, and intelligent.

Distribution Program - Evaluate new technologies, techniques, and concepts to identify proper investments that increase safety, reliability, and efficiency.

Transmission Operations and Planning Program - Improve reliability and stability by providing technology options to optimize the planning, design, construction, and operation of the company's transmission system.

Research and Environmental Management

EPRI Management and Technology Innovation Program - Ensure that the EPRI research plan is in line with Southern Company's research needs, effectively manage the EPRI-Tailored Collaboration program, and maximize the benefits of EPRI membership through effective technology transfer.

Advanced Generation Deployment Program – To support commercialization, deployment and to maintain the option of positioning coal based power generation as a key contributor to providing affordable, reliable and clean power generation as warranted.

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**Application for Decertification of Plant Branch
Units 3 and 4, Plant McManus Units 1 and 2,
Plant Kraft Units 1-4, Plant Yates Units 1-5,
Plant Boulevard Units 2 and 3, and Plant Bowen
Unit 6**

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**Application for Decertification of Plant Branch Units 3 and 4,
Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5,
Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6**

1. INTRODUCTION

In accordance with and as supported by Georgia Power Company's ("Georgia Power" or the "Company") 2013 Integrated Resource Plan ("IRP"), the Company hereby files this Application for Decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6 ("2013 Decertification Application") pursuant to O.C.G.A. § 46-3A-3 and Commission Rules 515-3-4-.08. The units presented for decertification represent 2,093 megawatts ("MW") of generating capacity and have had a long and distinguished history of service to Georgia Power customers and a significant positive impact on the communities in which they operate. Only after extensive analysis and evaluation and after exploring a wide range of feasible compliance options did the Company determine that retirement and decertification of these units is in the best interest of all customers. The Company hereby incorporates by reference all other portions of the Company's 2013 IRP filing into this 2013 Decertification Application.

2. DECERTIFICATION REQUESTS

2.1 Need for Decertification

As detailed in Sections 1.1, 1.5, and Section 6 of the Main Document, the projected costs to comply with the United States Environmental Protection Agency's Mercury and Air Toxics Standards ("MATS") rule and other pending environmental regulations have placed significant pressure on the economic viability of several of the Company's fossil generating units, resulting in the determination that retirement and decertification is the most cost-effective approach for Plant Branch Units 3 and 4, Plant Kraft Units 1-4, Plant McManus Units 1 and 2, and Plant Yates Units 1-5. And though the MATS rule and other existing and pending environmental regulations are the key drivers, the current forecasts of natural gas prices and the recent economic downturn and resulting loss of load have also had a negative impact on the economics of these units. While these units have provided significant benefit to customers, the economic analysis now

shows that retirement is in the best interest of all customers.

Plant Branch Units 3 and 4 are two coal-fired units with a total capacity of 509 MW and 507 MW respectively and were placed in service in 1968 and 1969, respectively. Plant Kraft Units 1-4 are coal-fired units that were placed in service at various times between 1958 and 1971 and have a total generating capacity of 316 MW. Plant McManus Units 1 and 2 are oil-fired steam plants that went in service in 1952 and 1959, respectively, and have 43 MW and 79 MW of generating capacity, respectively. Plant Yates Units 1-5 are coal-fired generating units that were placed into service at various times between 1950 and 1958 and have 579 MW of total generating capacity. The economic analyses for Plant Branch Units 3 and 4, Plant Kraft Units 1-4, Plant McManus Units 1 and 2, and Plant Yates Units 1-5 are contained in Sections 1.6.2, 1.6.5, 1.6.7, and 1.6.10 of the Unit Retirement Study in Technical Appendix Volume 2. The analysis for each unit shows that it is not beneficial for customers for the Company to invest in these units to allow for continued operations.

As detailed in Sections 1.1, 1.5, and Section 6 of the Main Document, the Company is also seeking to decertify Plant Boulevard Units 2 and 3 and Plant Bowen Unit 6. Plant Boulevard Units 2 and 3 are two oil-fired combustion turbines (“CT”) rated at a capacity of 14 MW each, and were installed in 1970 along with Unit 1. Both units recently experienced a significant equipment failure and the Company’s economic analysis demonstrates that the repairs are not in customers’ best interest. The economic analysis supporting the retirement of Plant Boulevard Units 2 and 3 can be found in Section 1.6.12 of the Unit Retirement Study. Plant Boulevard Unit 1 is not damaged and remains a cost-effective unit for customers, and therefore, is recommended for continued operation. The Company has similarly determined that it will be economically beneficial for customers to retire Plant Bowen Unit 6. Plant Bowen Unit 6 is a 32 MW oil-fired CT that is only permitted to operate during non-summer months due to ozone nonattainment requirements in the area. The economic analysis supporting the retirement of Plant Bowen Unit 6 can be found in Section 1.6.13 of the Unit Retirement Study.

2.2. Request for Expedited Decertification of Plant Bowen Unit 6

As detailed in Section 1.1 and Section 6 of the Main Document, the Company requests expedited decertification of Plant Bowen Unit 6 by no later than April 16, 2013. The Company

seeks decertification for Unit 6 due to the unfavorable economics of continued operation. In addition, Plant Bowen Unit 6 is located in close proximity to the planned baghouse construction activity for Units 3 and 4. Therefore, the Company plans to remove the unit from its current location, pending Commission approval of the Company's decertification request.

In light of the unfavorable economics and the proximity of the unit to the construction activity, the Company proactively sought sale opportunities for the generator and was able to reach an agreement to sell the unit (which agreement is contingent on Commission approval of decertification). Due to the current construction schedule for the Plant Bowen Units 3 and 4 baghouses, Unit 6 needs to be removed no later than June 1, 2013, and the purchase agreement thus requires that the buyer remove the unit by May 31, 2013. However, in order to allow the buyer sufficient time to meet the May 31, 2013 removal date, the purchase agreement conditions the sale on Commission approval of the decertification of the unit by April 16, 2013. If decertification is not achieved by April 16, 2013, the purchase agreement will be terminated by Georgia Power, and the deposit will be returned to the potential purchaser. Therefore, the Company requests expedited decertification of Plant Bowen Unit 6 by no later than April 16, 2013. Expedited decertification is appropriate in this case because of the clarity of the economic analysis and because of the logistical benefits of the sale in connection with the construction schedule of the baghouses for Units 3 and 4. Furthermore, proceeds from the sale will eliminate the remaining net book value of Unit 6.

Additional financial details regarding Plant Bowen Unit 6 and a copy of the purchase agreement are provided in the Selected Supporting Information in Technical Appendix Volume 2. The buyer is unaffiliated with Georgia Power or any of its affiliates.

2.3 Analysis of Transmission Impacts

In accordance with the Commission’s order in Docket No. 31081, the Company performed an analysis of the results of the requested decertifications on transmission facilities. The transmission facilities added, modified or avoided as a result of this decertification request are as follows:

Plant	Project Name	Date	Impact
Plant McManus Units 1 and 2	McManus - West Brunswick 115kV Rebuild	2014	Project no longer needed if Plant McManus Units 1 and 2 are retired
Plant Kraft Units 1-4	McIntosh-Blandford-Meldrim 230kV BLK & WHT Reconductor	2014	Projects needed if Plant Kraft Units 1-4 are retired
	Boulevard 230/115kV Project	2015	
	Plant Kraft 115/46kV #2 Transformer Project	2015	
Plant Yates Units 1-5	Dyer Road 230/115kV	2015	Projects needed if Plant Yates 1-5 are retired
	Corn Crib 230/115kV Substation	2018	
Projects not associated with a single plant retirement	North Tifton Second 500/230kV Auto	2014	Projects needed due to plant retirements but not associated with a single plant retirement
	Jasper - Pine Grove Primary 115kV Rebuild	2014	
	First Avenue - Victory Drive	2015	
	Raccoon Creek - Thomasville 230kV Reconductor (GPC Portion)	2015	
	Douglas - Pine Grove 230kV Project	2015	

2.4 Cost Recovery

In connection with the requested decertifications, the Company requests that the Commission approve the following:

- 1) Reclassification of the remaining net book values of Plant Branch Units 3 and 4 and Plant Boulevard Units 2 and 3 as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 31958;
- 2) Amortization of approximately \$38 million of Plant Branch Units 3 and 4 and approximately \$14 million of Plant Yates Units 6 and 7 environmental construction work in progress ("CWIP") (which has been reclassified as a regulatory asset in accordance with the Commission's Order in Docket No. 31958) ratably over a three year period beginning January 2014;
- 3) Reclassification of any unusable material and supplies ("M&S") inventory balance expected to be remaining at the unit retirement dates to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 31958 for recovery over a period to be determined by the Commission in the Company's next base rate case following the unit retirements; and
- 4) In the event the Commission does not approve the expedited decertification of Plant Bowen Unit 6, the Company requests the reclassification of the remaining net book value of Plant Bowen Unit 6 as of its respective retirement date to a regulatory asset account and the amortization of such regulatory asset account ratably over a period equal to the unit's remaining useful life approved in Docket No. 31958.

3. CONCLUSION

As set forth in the Company's 2013 IRP, Georgia Power's current supply-side plan, which incorporates the requested decertifications contained herein, is sufficient to provide cost-effective and reliable sources of capacity and energy through 2015 and beyond. The known and reasonably expected effects of these retirements on the Company's 2013 IRP are described more fully in the Main Document and the Technical Appendices. The requests contained in this 2013 Decertification Application are in the public interest and substantially comply with the relevant Commission rules. Therefore, the Company requests that the Commission approve the following:

- 1) Decertification of Plant Branch Units 3 and 4, Plant Yates Units 1-5, and Plant McManus Units 1 and 2 effective by the MATS compliance date of April 16, 2015;

- 2) Decertification of Plant Kraft Units 1-4 one year past the MATS compliance date (by April 16, 2016);
- 3) Decertification of Plant Boulevard Units 2 and 3 effective as of the date of the final order in this proceeding;
- 4) Expedited decertification of Plant Bowen Unit 6 by April 16, 2013; and
- 5) The related cost recovery as detailed in Section 2.4.