PUBLIC DISCLOSURE

Environmental Compliance Strategy

Update for 2014

Georgia Power Company

August 2014

FORWARD-LOOKING STATEMENT CAUTIONARY NOTE

This report contains forward-looking statements. Forward-looking statements include, among other things, current and proposed environmental regulations and related compliance plans and estimated expenditures, completion dates of construction projects, economic growth; sources of fuel, and estimated construction and other capital expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include: the impact of recent and future federal and state regulatory changes, including environmental laws including regulation of water, coal combustion residuals, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in laws and regulations to which Georgia Power is subject, as well as changes in application of existing laws and regulations; current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending Environmental Protection Agency civil actions against Georgia Power, Federal Energy Regulatory Commission matters, and Internal Revenue Service and state tax audits; variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions; available sources and costs of fuels; ability to control costs and avoid cost overruns during the development and construction of facilities; ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any operational and environmental performance standards, including any Public Service Commission requirements and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction; the direct or indirect effect on Georgia Power’s business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion; catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences; and the direct or indirect effects on Georgia Power’s business resulting from incidents affecting the U.S. electric grid or operation of generating resources. Georgia Power expressly disclaims any obligation to update any forward-looking statements.

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1.0 Georgia Power Environmental Compliance Strategy and Overview

Overview

The Environmental Compliance Strategy serves as a roadmap for compliance for Georgia Power Company (”Georgia Power” or the “Company” or “GPC”) and the other retail affiliates of Southern Company. This roadmap establishes a general direction but allows for individual decisions to be made based upon specific information available at the time. This approach is an absolute necessity in maintaining the flexibility to match a dynamic regulatory compliance environment with a variety of available compliance options. This document addresses recent environmental rulings and requirements and reflects the most recent strategy and cost estimates for incorporating these requirements.

Georgia Power and Southern Company completed the initial Clean Air Act Amendments (CAAA) strategy in December 1990 and have produced updates or reviews in subsequent years. The information contained in this document includes the annual Environmental Compliance Strategy review for 2014 and updates for compliance with the Clean Air Act (CAA), Clean Water Act (CWA), Resource Conservation and Recovery Act (RCRA), and other environmental statutes and regulations.

Through 2013, Georgia Power has invested approximately $4.3 billion in capital projects to comply with applicable environmental statutes, including the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; and the Endangered Species Act. GPC’s annual totals have been $309 million, $152 million, and $113 million in 2013, 2012, and 2011, respectively. In Georgia Power’s Annual Report on Form 10-K for the year ended December 31, 2013, Georgia Power projected that base level capital expenditures to comply with existing statutes and regulations will be a total of approximately $1.1 billion from 2014 through 2016, with annual totals of approximately $543 million, $366 million, and $202 million for 2014, 2015, and 2016, respectively.

The Company’s compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of any new or revised environmental statutes and regulations that are enacted, including the proposed environmental legislation and regulations described in this document; the cost, availability, and existing inventory of emissions allowances; and the Company’s fuel mix.

A summary and overview of the Georgia Power environmental compliance program is provided below.

- Georgia Power has installed 10 selective catalytic reduction systems (SCRs). SCRs are currently installed and operating at the following Georgia Power units:

    - Plant Bowen Units 1, 2, 3, and 4
    - Plant Hammond Unit 4
    - Plant Wansley Units 1 and 2
    - Plant Scherer Units 1-3

- Georgia Power has installed flue gas desulfurization devices (scrubbers or FGDs) on 14 units. Scrubbers are currently installed and operating at the following Georgia Power units:

    - Plant Bowen Units 1, 2, 3 and 4
    - Plant Hammond Units 1, 2, 3 and 4 (single scrubber vessel)
    - Plant Wansley Units 1 and 2
    - Plant Yates Unit 1
    - Plant Scherer, Units 1-3

- Georgia Power has installed and is operating baghouses with activated carbon injection to reduce mercury emissions at Plant Scherer Unit 1, 2, and 3.

- Decisions have been made to install additional controls or switch to natural gas as the primary fuel for compliance with the Mercury and Air Toxics Standards (MATS) at the following Georgia Power units:

    - Plant Bowen, Units 3 and 4: baghouses with activated carbon injection (ACI) and lime injection (also referred to as alkali sorbent injection (ALK)), scrubber additive (also referred to as mercury re-emission control system (MRCS))
    - Plant Bowen, Units 1 and 2: ACI, ALK, MRCS
    - Plant Hammond, Units 1, 2, 3, and 4: ACI, ALK, MRCS
    - Plant Wansley Units 1 and 2: ACI, ALK, MRCS
    - Plant Scherer Units 1, 2, 3: calcium bromide
    - Plant McIntosh Unit 1: ACI and dry sorbent injection (DSI) used in conjunction with Powder River Basin coal
    - Plant Yates Units 6 and 7: natural gas
    - Plant Gaston Units 1, 2, 3, and 4, representing Georgia Power's share of SEGCO: natural gas

- These Georgia Power emission controls and the associated expenditures are based on compliance requirements with rules including Phase II of the 1990 Clean Air Act Acid Rain program; National Ambient Air Quality Standards, including the 1-hour and 8-hour ozone standards and the fine particulate matter standards; the regional NO_X trading program; the Clean Air Interstate Rule; the Clean Air Visibility Rule addressing both SO_2 and NO_X reductions to improve air quality in the national parks; the Georgia Multipollutant Rule and

SO_2 Emissions Rule; and the Mercury and Air Toxics Standards addressing mercury and other hazardous air pollutants.

- In addition, after thorough evaluation of the projected MATS compliance costs combined with the anticipated cost of other current and pending environmental regulations, Georgia Power has decided to retire rather than incur additional environmental control costs for the following units:

  - Plant Branch, Units 3 and 4
  - Plant Kraft Units 1, 2, 3, and 4
  - Plant McManus, Units 1 and 2
  - Plant Yates Units 1, 2, 3, 4, and 5
  - Plant Mitchell Unit 3 (Georgia Power to seek decertification in the 2016 IRP)

- Georgia Power has also previously decided to retire the following units based on environmental control expenditures required by the Georgia Multipollutant Rule:

  - Plant Branch, Units 1 and 2 (Unit 2 retired in 2013)

- Between 1990 and 2013, GPC investments have reduced NO_X and SO_2 emissions by approximately 88 and 91 percent, respectively (including Georgia Power's share of SEGCO).

- The combination of baghouses, SCRs, and scrubbers has reduced Georgia Power's 2013 mercury emissions by approximately 78 percent from 2005 levels (including Georgia Power's share of SEGCO).

The following graphic (Fig. 1-1) summarizes historical and projected emission reductions, generation increases and environmental capital costs (including Georgia Power's share of SEGCO).

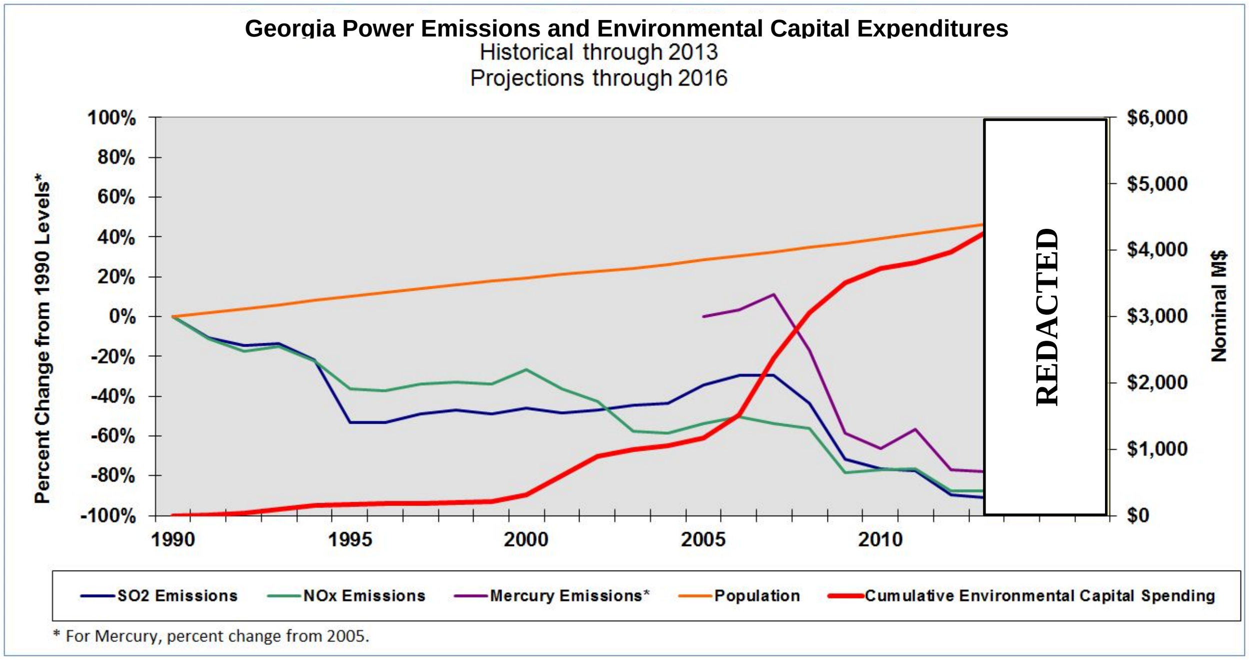


Figure 1-1 Georgia Power Emissions and Environmental Capital Expenditures (Emission Estimates are based on 2014 Energy Budget Projections)
*For mercury, the percent change is from 2005, when CAMR was finalized.

- Georgia Power and Southern Company have established a significant record of voluntary greenhouse gas (GHG) emissions reductions, beginning in the mid-1990s. Southern Company was a charter participant in the Department of Energy (DOE) Climate Challenge Program. Since the DOE program ended in 2005, Southern Company has continued with its voluntary emission reduction programs and has reduced or avoided approximately 415 million metric tons of CO_2 through 2013. In recent years, the company has significantly increased natural gas generation, achieved substantial improvements in nuclear availability and generation, and maintained an extensive demand-side management program.

- Georgia Power's development of two new nuclear units at Plant Vogtle as well as Southern Company's focus on developing advanced coal technology are important to preserving diverse fuel options in the long-term environmental compliance strategy.

- 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 Georgia Public Service Commission (PSC) and the renewable energy community, there are currently 95 MW of solar generation installed in Georgia (with another 204 MW under contract to be installed in the future), 198 MW of biomass generation including landfill methane gas, and 1,088 MW of hydro generation. Georgia Power's current solar programs are on track to foster the development of approximately 900 MW of solar generation by 2017. 250 MW of new wind PPAs were recently certified to begin serving Georgians by 2016 and contracts are executed for 217 MW of new biomass capacity to be developed in Georgia by 2017.

The following graphics show Georgia Power's historical and projected emissions for SO_2 (Fig. 1-2), NO_X (Fig. 1-3), mercury (Fig. 1-4), and carbon dioxide (Fig. 1-5), including Georgia Power's share of SEGCO. The historical emissions for SO_2, NO_x, and carbon dioxide are shown back to 1990, while mercury emissions are shown back to 1998.

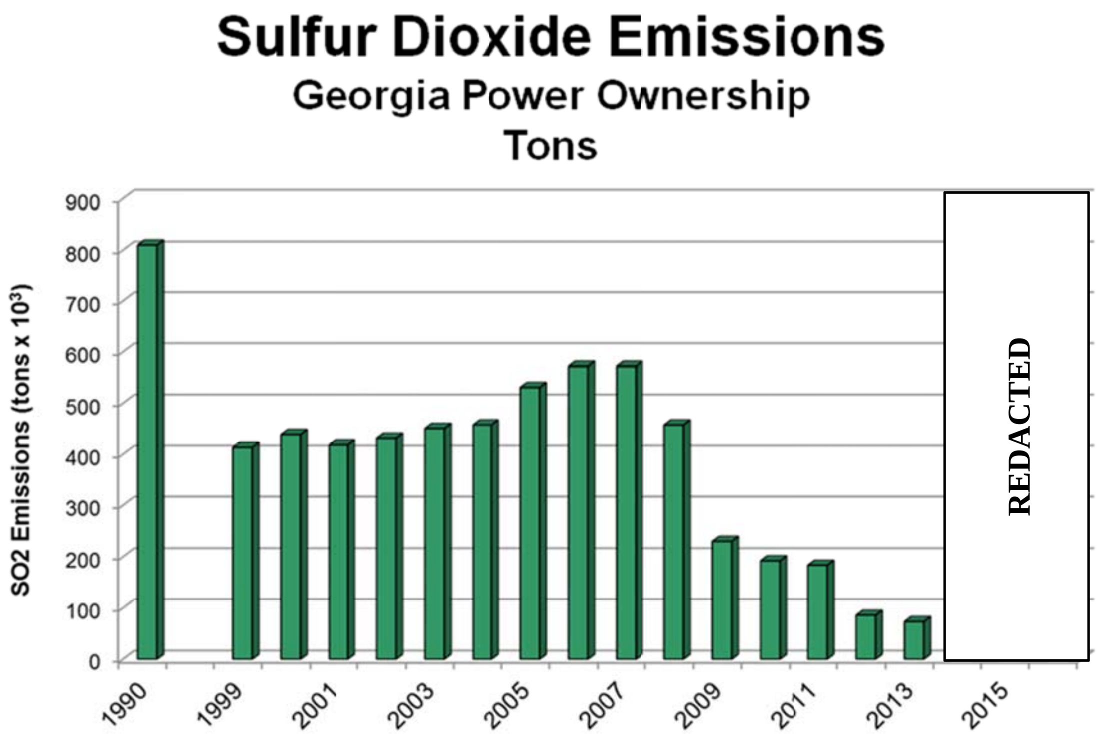


Figure 1-2 Historical and Projected SO_2 Emissions for Georgia Power

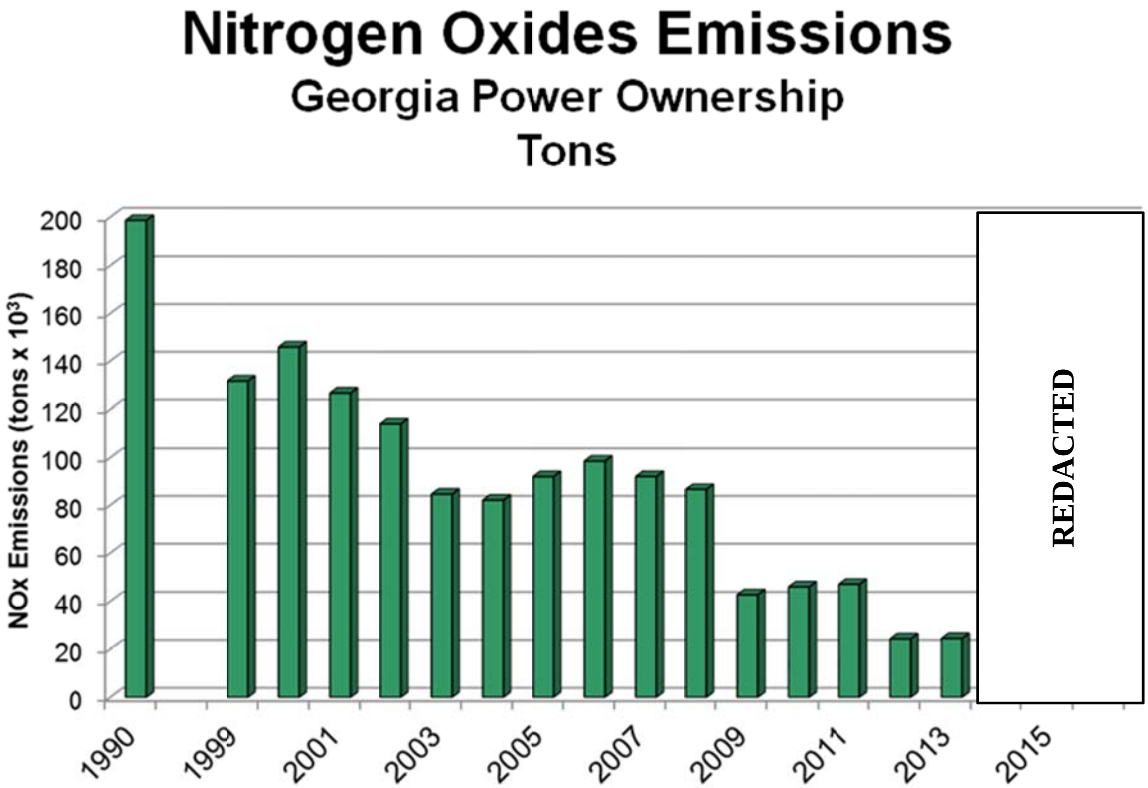


Figure 1-3 Historical and Projected NO_X Emissions for Georgia Power

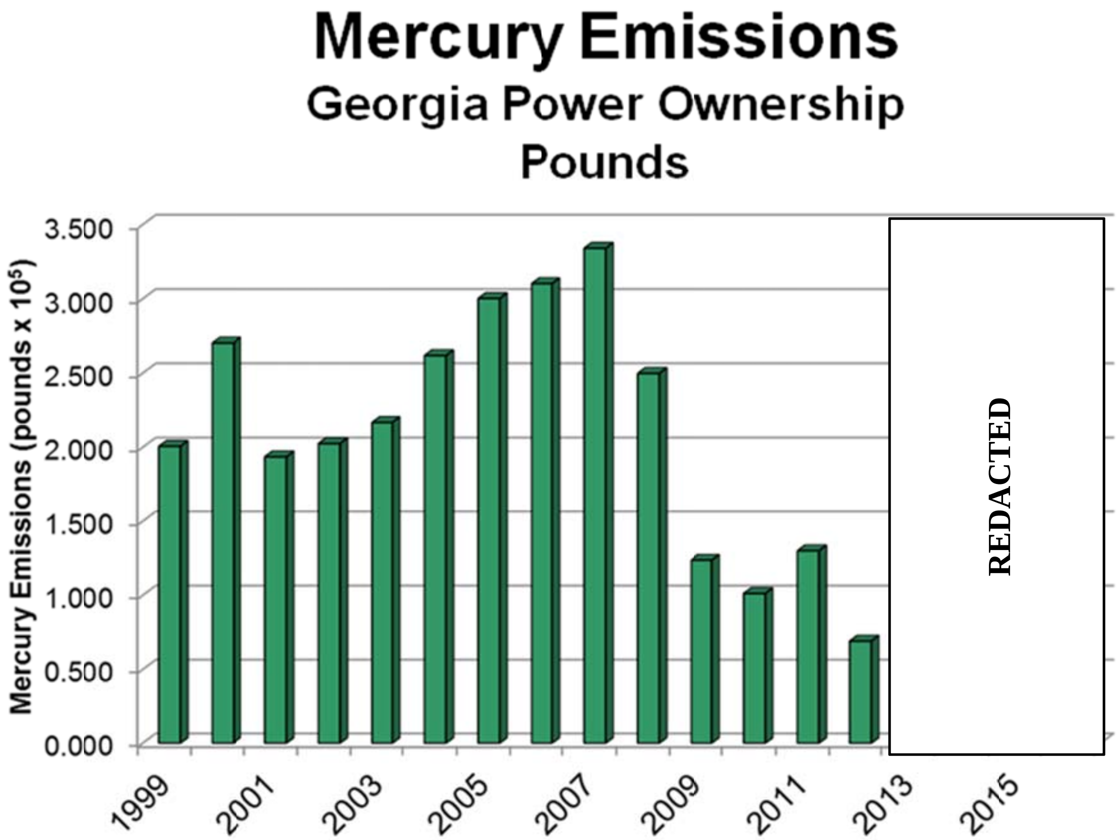


Figure 1-4 Historical and Projected Mercury Emissions for Georgia Power

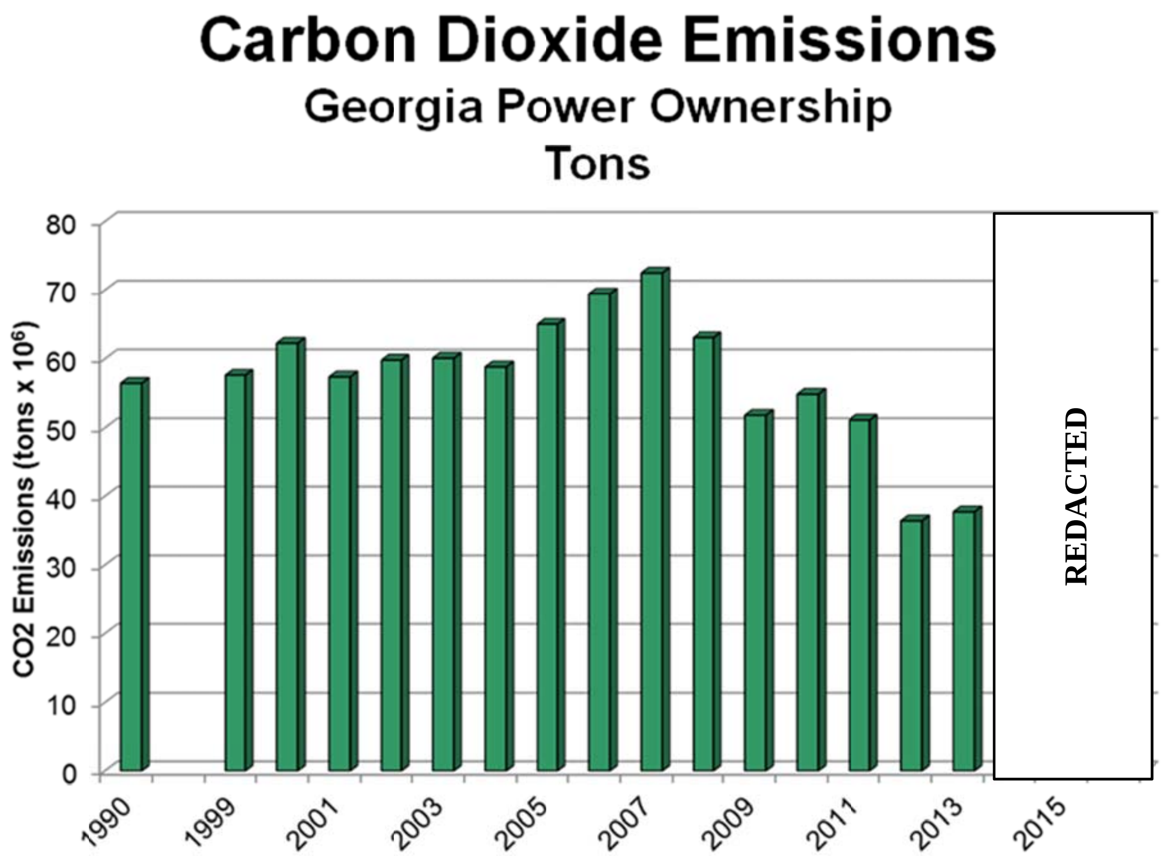


Figure 1-5 Historical and Projected CO_2 Emissions for Georgia Power

1.1 Notable Regulatory-Related Events

The following is a list of notable environmental regulatory events over the past seven years.

- **June 2007** – Georgia Environmental Protection Division (EPD) finalizes the Georgia Rule for Multipollutant Control for Electric Utility Steam Generating Units (Georgia Multipollutant Rule).
- **March 2008** – U.S. Environmental Protection Agency (EPA) finalizes new 8-hour ozone standard at 75 parts per billion (ppb).
- **July 2008** – D.C. Court of Appeals vacates Clean Air Interstate Rule (CAIR).
- **December 2008 –** D.C. Court of Appeals stays mandate vacating CAIR while EPA promulgates a new rule. CAIR remains in place.
- **January 2009 -** Georgia EPD finalizes the Georgia Rule for SO_2 Emissions from Electric Utility Steam Generating Units (Georgia SO_2 Emissions Rule).

- **October 2009** – EPA finalizes nonattainment designations for 2006 24-hour fine particulate matter standard.
- **December 2009** – EPA issues an "endangerment finding" for motor vehicles which formally determines that six greenhouse gases taken in combination endanger both the public health and public welfare.
- **January 2010 –** EPA promulgates new NO_2 1-hour 100 ppb standards.
- **May 2010** – EPA announces a proposed rule regulating Coal Combustion Byproducts under RCRA.
- **May 2010** – EPA releases Tailoring Rule that applies to stationary source air permitting for CO_2 and other GHGs.
- **June 2010 –** EPA finalizes new SO_2 1-hour 75 ppb standard.
- **February 2011** – EPA finalizes MACT rule for Industrial Boilers.
- **March 2011 –** EPA releases proposed 316(b) Rule.
- **July 2011** – EPA releases final Cross State Air Pollution Rule (CSAPR, formerly known as Transport Rule).
- **December 2011** – Upon challenge by industry and states, D.C. Circuit Court stays CSAPR and orders EPA to continue administering CAIR pending judicial review.
- **December 2011** – EPA releases the final MATS Rule (formerly known as the Utility MACT Rule).
- **March 2012 –** EPA releases the proposed Carbon Pollution Standard for New Power Plants, affecting new coal-fired and gas-fired Electric Generating Units.
- **June 2012** – EPA requests comment on additional compliance options for 316(b) rulemaking.
- **August 2012 -** D.C. Circuit Court vacates CSAPR and remands the proceeding back to EPA, requiring the Agency to continue administering CAIR pending a lawful replacement.
- **August 2012** – EPA announces delay in implementation of SO_2 NAAQS and attainment designations until 2013.
- **December 2012** – EPA finalizes a new PM2.5 NAAQS.
- **December 2012 –** EPA finalizes a revised Industrial Boiler MACT rule.

- **February 2013** – EPA proposed SIP Call that would require 36 states (including Georgia) to revise their SSM rules, claiming they are inconsistent with the Clean Air Act and EPA policy.
- **March 2013** – EPA signs final MATS reconsideration rule for new sources. EPA did not take final action on the reconsideration petition for startup/shutdown provisions for existing sources.
- **April 2013 –** Georgia EPD announces revisions to the Georgia Multipollutant Rule and SO_2 Emissions Rule.
- **April 2013** – EPA issues proposed steam electric effluent guidelines rule for wastewater discharges.
- **June 2013 -** President Obama released a memo for the EPA Administrator detailing a new regulatory timeline for GHG regulations.
- **July 2013** – EPA finalizes SO_2 NAAQS designations. No areas within Southern Company's service territory designated nonattainment.
- **September 2013 –** EPA releases re-proposed Greenhouse Gas New Source Performance Standards for New Power Plants.
- **March 2014** – EPA and the Corps proposed rule defining waters of the U.S. under the Clean Water Act.
- **April 2014** – SO_2 NAAQS "data requirements rule" proposal released.
- **April 2014 -** U.S. Supreme Court reversed the D.C. Circuit vacatur of CSAPR and remanded the case back to the D.C. Circuit court for further proceedings.
- **May 2014** – EPA signed the final 316(b) rule for cooling water intakes.
- **June 2014** – EPA proposes GHG standards/guidelines for modified, reconstructed, and existing sources.
- **June 2014** – U.S. Supreme Court vacates EPA's GHG Tailoring Rule.

1.2 Future Key Environmental Dates

The following is a summary of upcoming key environmental developments and potential estimated dates.

- **September 2014** – EPA scheduled to issue supplemental SSM SIP Call proposal pursuant to settlement with environmental petitioners.
- **Fall 2014 –** EPA expected to issue final reconsideration rule for startup/shutdown provisions of MATS for existing sources.
- **Late 2014** – EPA to finalize the Greenhouse Gas (GHG) Performance Standards for New Power Plants.
- **December 2014** – Final 2012 Annual PM2.5 NAAQS designations expected.
- **December 2014 –** Next proposed ozone NAAQS revision expected.
- **December 2014** – EPA to finalize Coal Combustion Residuals rule.
- **Early 2015** – EPA to finalize SO2 Data Requirements rule.
- **May 2015** – EPA scheduled to finalize SSM SIP Call rulemaking.
- **June 2015** – EPA to finalize greenhouse gas standards/guidelines for modified, reconstructed, and existing sources.
- **September 2015** – EPA scheduled to finalize the steam electric effluent guidelines rule for wastewater discharges.
- **October 2015 –** Anticipated date for final revised ozone NAAQS.
- **Late 2015** – Anticipated date for final Transport Rule to address the 2008 Ozone NAAQS.

These federal rules as well as applicable state rules are discussed in detail in Section 2.0. Section 3.0 of this document details the process of developing the Environmental Compliance Strategy, and Section 4.0 discusses the results of the strategy and impacts of these environmental regulations to Georgia Power's operations.

2.0 Regulatory, Legislative, and Judicial Review

Environmental compliance and regulation for Georgia Power Company (GPC) and all of Southern Company are principally governed by the U.S. Environmental Protection Agency (EPA), the State of Georgia Environmental Protection Division (EPD), and other state and local authorities. The major environmental laws and regulations impacting Georgia Power, including any recent legislative, regulatory, or judicial developments, are detailed in this section.

2.1 Major U.S. Environmental Laws

Clean Air Act (CAA)

The portions of the Clean Air Act and the 1990 Clean Air Act Amendments (CAAA) that impact the electric utility industry most directly are:

- Title I, National Ambient Air Quality Standards
- Title III, Air Toxics
- Title IV, Acid Rain
- Title V, Permits

The heart of the CAA is the National Ambient Air Quality Standards (NAAQS or "standards"). The Act requires that the U.S. EPA determine what level of six specific pollutants (ozone, particulate matter, sulfur dioxide, lead, carbon monoxide, and nitrogen dioxide) in the ambient (outside) air is protective of human health with a margin of safety. Areas of the country where levels of these pollutants exceed the NAAQS are known as "nonattainment" areas. States must develop State Implementation Plans (SIPs) with control strategies designed to bring these areas into attainment. EPA is required to review the NAAQS every five years, and update them if necessary. In addition, the CAA authorizes EPA to issue regulations necessary to prevent emissions in one or more states from contributing to nonattainment in other states. EPA has issued three sets of rules for managing interstate nonattainment that have been applicable to Southern Company units – the NO_x Budget Trading Rule (NO_x SIP Call), CAIR, and CSAPR (as a replacement to CAIR). Since CSAPR has been stayed by the DC Circuit Court pending further deliberations, CAIR remains in place.

Title III of the CAAA requires regulation of 187 Hazardous Air Pollutants (HAPs) and requires implementation of emission limits equivalent to the Maximum Achievable Control Technology (MACT) for specific source categories, as determined by EPA. Many different MACT rules affect the electric utility industry, including, notably, the final Mercury and Air Toxics Standards (MATS, formerly known as the Utility MACT Rule). MACT standards are set by EPA according to the emissions performance of the best performing sources in the country for a particular source category. Once in place, MACT standards are to be reviewed by EPA every eight years.

The 1990 Amendments also added the Acid Rain Program (Title IV). This program required reductions in the emissions of sulfur dioxide and nitrogen oxides to reduce acid rain. The Acid Rain Program had the most immediate impact on Southern Company and the electric utility industry following the 1990 amendments.

Title V of the CAAA added requirements for facilities to obtain legally-enforceable operating permits. The permits are meant to clearly lay out most of the applicable air quality-related regulations for affected facilities, mainly large sources, by compiling all applicable requirements into one document. The Title V permit includes both state and federal requirements and is issued by the Georgia EPD. Sources must obtain permit amendments when new requirements come into effect or when certain changes are made at the facility.

Clean Water Act (CWA)

The CWA prohibits the discharge of pollutants into waters of the United States except in compliance with the Act. Authority to discharge pollutants under the CWA may be granted through a National Pollutant Discharge Elimination System (NPDES) permit issued by EPA or a state under a delegation of authority from EPA. The NPDES program is used as a means of achieving and enforcing technology-based and water quality-based effluent limitations.

EPA has established “effluent limitations guidelines” for the steam electric industry and other industrial source categories based on treatment technologies. These guidelines were promulgated in 1974 and last amended in 1982. EPA is responsible for periodically reviewing and updating these effluent limitations guidelines, which serve as the basis of the technology-based permit limits that appear in individual NPDES permits.

Section 316(b) of the CWA, which regulates cooling water intake structures, is implemented through NPDES permits. The Section 316(b) regulations are intended to protect fish and other aquatic species in the vicinity of utility cooling water intake structures. The focus of Section 316(b) is to ensure that the location, design, construction, operation, and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being impinged or entrained.

Resource Conservation and Recovery Act (RCRA)

This law governs the generation, transportation, treatment, storage and disposal of solid and hazardous waste. A major focus for electric utilities has been regulatory treatment of coal ash and other coal combustion residuals (CCRs) under RCRA and potential regulations affecting their management and disposal. In response to a December 2008 spill at a TVA facility, EPA is currently working on rulemaking that would represent a significant departure from its historical interpretations and make CCRs and ash ponds subject to federal regulation under RCRA.

The relevant programs and regulations derived from these laws are discussed in more detail in the following sections.

2.2 Acid Rain Program

For almost twenty years, Southern Company has been planning and implementing measures to comply with the requirements of the Title IV Acid Rain provisions of the 1990 CAAA. Reductions in SO_2 and NO_X under the program were required in two phases – Phase I, beginning in 1995 and Phase II, beginning in 2000. Under the program, EPA issues emissions allowances for SO_2 and requires that regulated units demonstrate that they have sufficient allowances to cover their SO_2 emissions for each year. The regulations also set limitations on NO_X emissions. This program allows plants to comply with the NOx limits individually, but also provides the option to comply through an averaging plan across multiple units.

2.3 Ambient Air Quality Standards

The cornerstone of the CAA is attainment of the NAAQS for the following six pollutants: carbon monoxide (CO); sulfur dioxide (SO_2); nitrogen dioxide (NO_2); ozone; lead; and particulate matter (PM). While the CAA has not been significantly amended since 1990, EPA's implementation of the Act and related court determinations continue to evolve. The CAA specifically requires the EPA to review the primary and secondary NAAQS every 5 years and to revise them as necessary. These reviews have resulted in multiple, significant changes to the ozone and particulate matter NAAQS beginning in 1997. EPA has also recently revised the SO_2 and NO_2 NAAQS significantly. Implementing these standards is generally a state responsibility; however, the EPA has also issued rules, such as the NO_x SIP Call, CAIR, and the Cross-State Air Pollution Rule, that deal with the transport of pollutants on a regional or multi-state basis to facilitate attainment with the NAAQS.

Ozone

Ozone is formed by a chemical reaction in the atmosphere between NO_X emissions and volatile organic compounds (VOCs). This reaction is driven by sunlight, and thus ozone formation is typically much more significant during the summer months. In 1979, EPA put into place a limit on 1-hour ozone concentrations of 120 ppb. Subsequently, the agency established an 8-hour standard of 80 ppb in 1997 and revoked the 1-hour standard for most areas in 2005. Areas within Georgia Power's service area that were designated as nonattainment under the 8-hour ozone standard included Macon and a 20-county area that includes metropolitan Atlanta. Macon was redesignated to attainment with the standard on October 19, 2007. The Atlanta area was redesignated to attainment on December 2, 2013 (effective January 2, 2014).

On March 12, 2008, EPA issued a final rule to establish a more stringent 8-hour ozone standard, setting the standard at 75 ppb. However, on September 16, 2009 EPA announced its intent to reconsider the 2008 ozone standard and delayed implementing the standard while the agency conducted additional review. In January 2010, EPA announced it was considering a proposed revision to the 8-hour ozone standard, lowering the level from 75 ppb to a level in the range 60 to 70 ppb. Such a revision would have resulted in a large number of new nonattainment areas throughout the country, including many new areas within Georgia Power's service territory. In fact, at 70 ppb, 75% of monitored counties in the U.S. would have been nonattainment; at 60 ppb, 96% of monitored counties in the U.S. would have been nonattainment. President Obama asked EPA to withdraw its reconsideration of the 2008 ozone NAAQS in September 2011.

EPA then turned its attention to implementing the 2008 ozone NAAQS. In June 2012, EPA finalized attainment/nonattainment designations for the 2008 standard. Fifteen counties around Atlanta, including Bartow, Cherokee, Clayton, Cobb, Coweta, DeKalb, Douglas, Fayette, Forsyth, Fulton, Gwinnett, Henry, Newton, Paulding, and Rockdale, were designated as nonattainment (see Figure 2.3-1 below). Atlanta was classified as a “marginal” nonattainment area, which means that it must attain the 2008 standard by 2015. If the area does not achieve attaining air quality by 2015, then the area classification will be “bumped up” to “moderate”, and Georgia EPD may require additional emission reductions.

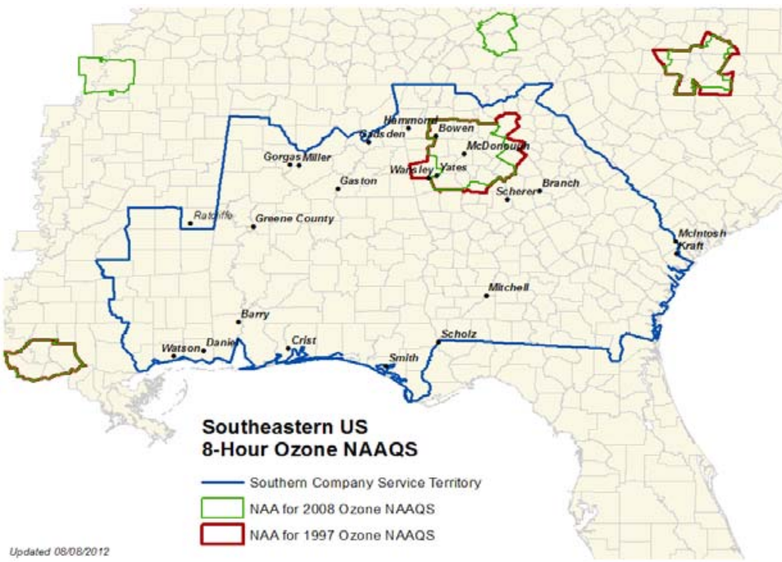


Figure 2.3-1 Southeastern U.S. Ozone Nonattainment Analysis

As required by the CAA, the EPA is currently reviewing the ozone NAAQS but has not met the statutory deadline for finalizing the review. EPA is currently expected to propose a revision to the standard by December 1, 2014 and to finalize a revision by October 1, 2015. EPA is anticipated to lower the 8-hr standard from its current level of 75 ppb to a value in the range of 60 to 70 ppb. The graphic (Fig. 2.3-2) below shows areas of the Southeast that are at risk of being designated nonattainment of a revised standard. Areas within the Georgia Power service territory could be designated nonattainment.

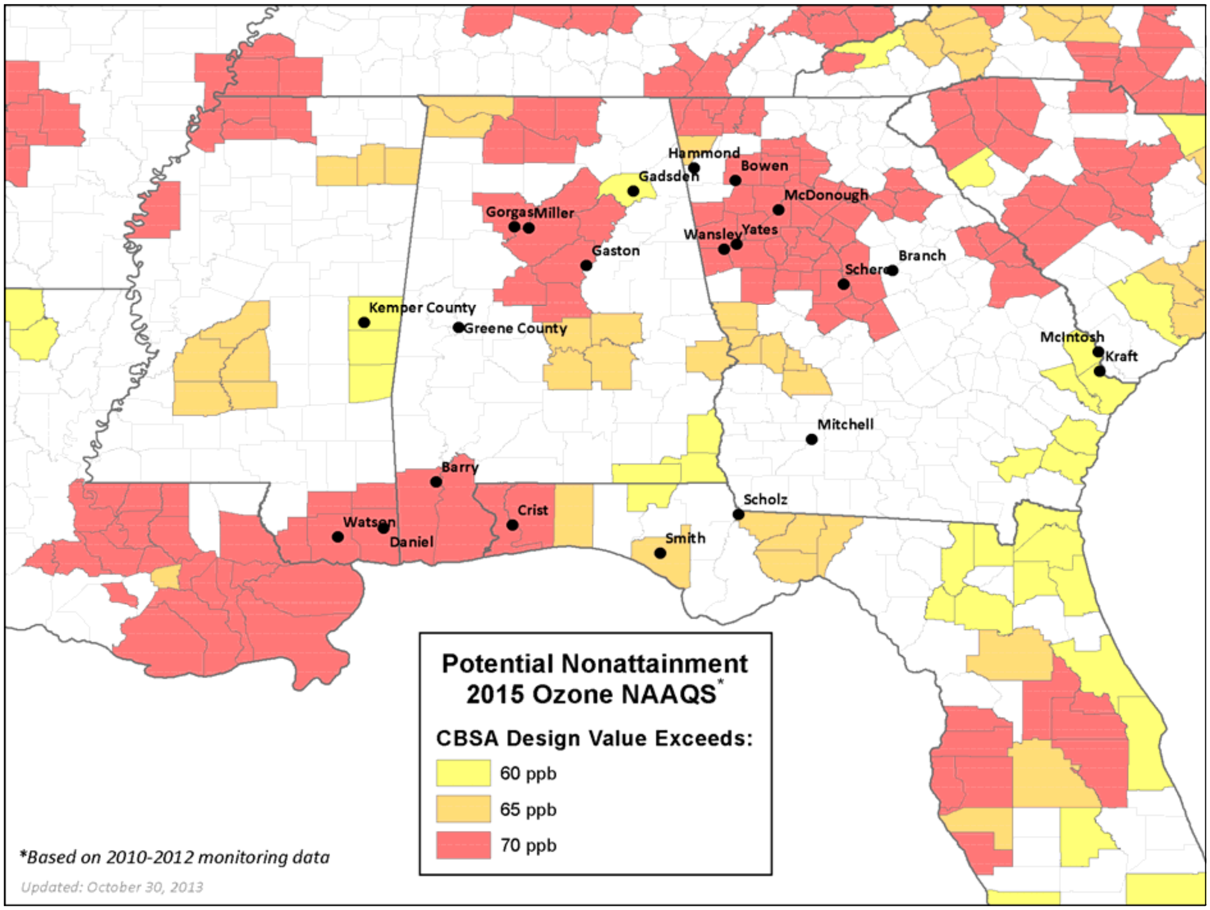


Figure 2.3-2: Potential Nonattainment Areas for a Revised (2015) Ozone Standard

Particulate Matter

There are several fine particulate matter (PM2.5) standards with potential implications to Georgia Power. In 1997, EPA finalized its first fine particulate (PM2.5) standard at a level of 15 micrograms per cubic meter (µg/m^3) on an annual average and 65 µg/m^3 on a 24-hour average. In 2005, several areas within Georgia were designated as nonattainment for the annual standard. One of the measures enacted by Georgia EPD to reduce emissions in Georgia's PM2.5 nonattainment areas was the Georgia SO_2 Emissions Rule, discussed in more detail in Section 2.10. The Georgia SO_2 Emissions Rule requires reductions of SO_2, which can form PM2.5 upon being emitted into the atmosphere, from various power plants by specified compliance deadlines.

By 2012, all areas within Georgia had air quality data showing attainment of the 1997 PM2.5 annual standard. Specifically, on May 5, 2011, July 5, 2011, June 30, 2011, and January 9, 2012, the EPA promulgated final determinations of clean data for the Floyd County, Macon, Chattanooga and Atlanta nonattainment areas, respectively, for achieving air quality that meets the 1997 annual PM2.5 standard. EPA has issued final redesignations for Floyd County (on May

14, 2014, effective June 13, 2014) and Macon (on May 13, 2014, effective June 12, 2014), and Georgia EPD's request for official redesignation of Chattanooga and Atlanta are still pending. In September 2006, the EPA published a final rule which retained the annual PM2.5 standard (15 $\mu g/m^3$), but increased the stringency of the 24-hour PM2.5 air quality standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$. All parts of Georgia were found to meet or be in compliance with the 2006 24-hour fine particulate matter standard. The Georgia EPD still has obligations under the 24-hour PM2.5 standard, however, to address interstate transport of emissions, *i.e.* emissions from Georgia that may contribute to nonattainment in other states. The Cross State Air Pollution Rule (CSAPR) discussed in Section 2.5 was intended to address interstate transport of emissions from Georgia and other states for the PM2.5 standards. With the pending CSAPR legal proceedings, whether additional requirements may apply to address interstate transport under the annual and 24-hour PM-2.5 standards remains to be determined.

In addition to the existing 1997 and 2006 standards, EPA recently completed its five-year review of the particulate NAAQS. As required by court order, on June 14, 2012, EPA issued a proposed rule that would increase the stringency of the primary NAAQS by lowering the annual PM2.5 standard in the range of 12 to 13 $\mu g/m^3$. EPA announced the final PM2.5 revised standard on December 14, 2012, as agreed to in a settlement filed with the court. The final rule lowers the annual standard to 12 $\mu g/m^3$ and could result in new areas being designated as nonattainment. In December 2013, the Georgia EPD recommended to the EPA that no areas within Georgia be designated nonattainment based on its expectation that the downward trend in air quality readings would continue and bring all monitors into attainment before EPA finalizes the designations. EPA is not expected to finalize nonattainment designations for the 2012 PM2.5 standard until early 2015. The states will then have the responsibility for development of the SIPs which will outline compliance requirements across all industry sectors. States SIPs are anticipated to be developed by mid-2016 with a deadline for attainment of December 2021.

NO_2 and SO_2

On April 12, 2010 and June 22, 2010, new short-term (1-hour) NAAQS for NO_2 and SO_2, respectively, became effective.

The NO_2 ambient air quality standard was set at 100 ppb, to be achieved at the 98th percentile level (i.e., the 3-year average of the 8th highest of the daily 1-hour maximum concentrations). EPA intends to initially focus on monitoring of short-term peak concentrations which occur near major roadways, and the rule imposes new roadside monitoring requirements in the urban areas with a population greater than 500,000. EPA's initial designations based on available monitoring data classify the entire country as unclassifiable/attainment. Although none of the areas within Georgia are designated as nonattainment for the standard based on current ambient air quality monitoring data, the NO_2 standard could still result in significant additional compliance and operational costs for new units and major modifications conducted at facilities that require permitting. EPA expects to make additional designations based on a new monitoring requirement focused on roadside monitors, which would be phased in between 2014-2017.

The SO_2 ambient air quality standard was set at a level of 75 ppb, to be achieved at the 99th percentile level (i.e. the 3-year average of the 4th highest of the daily 1-hour maximum concentrations). In the 2010 SO_2 NAAQS final rule, EPA outlined a plan to implement the standard through a combination of monitoring and modeling. Areas with either monitoring or modeling showing violations of the NAAQS would be classified nonattainment. All other areas would be considered unclassifiable. For unclassifiable areas, EPA issued guidance that required states to submit, as part of their 110(a)(2) infrastructure SIP due in June 2013, modeling analyses showing that all unclassifiable areas would achieve the NAAQS by establishing federally enforceable permit limits on SO_2 emissions. However, on April 12, 2012, EPA notified state environmental commissioners that they would no longer require modeling analyses in the Infrastructure SIP submittals. In early May 2012, EPA posted a draft white paper laying out options for and discussing implementation of the 2010 primary 1-hour SO_2 NAAQS. Between May 30 and June 1, 2012, EPA met independently with three stakeholder groups (environmental groups, state and tribal representatives, and industry) to interactively discuss the white paper. Designations for this NAAQS were expected in June 2012, but on July 27, 2012, EPA announced that designations would be delayed by up to 1 year. In February 2013, EPA notified States of which areas the Agency intended to initially designate nonattainment for the 1-hour SO_2 NAAQS, based on available monitoring data. No areas within Georgia Power's service territory were designated nonattainment. EPA also issued a white paper outlining its strategy for making additional designations for the rest of the areas of the country that were not addressed in the "initial" nonattainment designations. On May 21, 2013, EPA posted draft Technical Assistance Documents (TADs), which were updated on January 7, 2014, that outline the Agency's strategy on the use of modeling and monitoring for designation purposes. On August 5, 2013, EPA promulgated final "initial" nonattainment designations for 29 areas of the country in 16 states, but declined to designate the rest of the country. These nonattainment designations were based on monitoring data that showed violations of the standard. No areas in Georgia were designated.

EPA continued its implementation of the 2010 SO_2 NAAQS with a proposed Data Requirements Rule released in April 2014 detailing the regulatory requirements for determining nonattainment areas and related requirements through modeling and/or monitoring. The proposal outlines the EPA preferred option and alternative options for defining "large" SO2 emissions sources. Under the modeling track, modeling would be required for large SO2 emission sources by January 2017, with area designations and attainment demonstrations due December 2017 and August 2019, respectively. Under the monitoring track, states must install monitors as appropriate and collect three years of monitoring data from 2017 to 2019, with area designations and attainment demonstrations due December 2020 and August 2022, respectively. Southern Company submitted comments to the proposed Data Requirements Rule on July 14, 2014. On June 2, 2014, EPA published notice of a proposed consent decree with environmental groups settling claims that EPA failed to complete the area designation process by the statutory deadlines and agreeing to complete area designations in three stages. The proposed schedule would require EPA to designate some areas much more quickly than proposed in the Data

Requirements Rule and could potentially impact some areas in Georgia. Areas designated as nonattainment would have to follow more stringent air permitting and control rules. Southern Company and Georgia Power submitted comments on the proposed consent decree to EPA on July 2, 2014 objecting to the terms of the consent decree.

2.4 Regional NO_X SIP Call and Budget Trading Program

In September 1998, the EPA issued the final Regional NO_X SIP Call rule, which required 22 states and the District of Columbia (D.C.) to submit SIPs to address regional transport of the ozone precursor, NO_X. The rule requires NO_X emission reductions sufficient to meet specified emission budgets for each affected state.

The rule was challenged in the D.C. Circuit Court of Appeals but largely upheld by the Court. However, the Court vacated the rule for Georgia, Missouri, and Wisconsin. In April 2004, EPA reissued the NO_X SIP Call as applied to the northern two-thirds of Georgia and the eastern half of Missouri, in accordance with the Court's decision. Before issuance of the final rule, however, the two areas Georgia was determined to be impacting (Birmingham, Alabama and Memphis, Tennessee) came into attainment for the one-hour ozone standard. On this basis, the Georgia Coalition for Sound Environmental Policy petitioned EPA to reconsider the final rule. EPA granted that petition and stayed the 2004 NO_X SIP Call rule as applied to Georgia. Following reconsideration in April 2008, EPA issued a final rule rescinding the NO_X SIP Call as applied to Georgia. The State of North Carolina challenged this action in the D.C. Circuit, and a decision was reached by the Court on November 24, 2009. The Court found that North Carolina failed to demonstrate that including Georgia in the NO_X SIP Call would redress North Carolina's asserted injury and, therefore, North Carolina lacked standing. As a result, the Court dismissed North Carolina's petition, and the NO_x SIP call does not apply in Georgia.

2.5 CAIR/CSAPR

Clean Air Interstate Rule (CAIR)

The EPA issued the final CAIR in March 2005. CAIR was designed to reduce SO_2 and NO_x emissions that contribute to nonattainment of the ozone and PM2.5 NAAQS in twenty-eight Eastern states, including Georgia and Alabama. It is based on a cap-and-trade regulatory scheme for NO_x and SO_2 that requires sources to hold allowances equal to their emissions. Annual emission reductions were required in two phases, with the first phase of compliance beginning in 2009 for NO_X (regional cap: 1.5 million tons or a reduction of approximately 50 percent from then current emissions levels) and 2010 for SO_2 (regional cap: 3.6 million tons or a reduction of approximately 50 percent from Acid Rain Program allocations). The second phase is scheduled for 2015 (regional cap: 1.3 million tons or a reduction of approximately 65 percent from then current emissions levels for NO_x and 2.5 million tons or a reduction of approximately 70 percent from Acid Rain Program allocations for SO_2). Georgia and Alabama are affected for the PM2.5 requirements, and power plants in these states are required to hold allowances to meet annual emission caps for SO_2 and NO_x (precursors to PM2.5). Alabama, but not Georgia, is also affected for the ozone season requirements, and power plants there are required to have allowances to meet summer-season NO_x caps.

On July 11, 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the United States Court of Appeals for the District of Columbia Circuit issued a decision vacating CAIR in its entirety and remanding it to EPA for further action consistent with its opinion. In December 2008, however, the U.S. Circuit Court amended its July decision in response to the rehearing petitions and remanded CAIR to EPA without vacatur, thereby leaving CAIR compliance requirements in place while EPA developed a revised rule.

Cross State Air Pollution Rule (CSAPR)

On July 7, 2011 EPA released the final Cross State Air Pollution Rule (CSAPR) as a replacement to CAIR. The final rule applied to 27 states, including Georgia and Alabama. Like CAIR, CSAPR established an annual allowance trading program for SO_2 and NOx to reduce transport of fine particulate matter and a separate ozone season NO_x allowance trading program to reduce ground-level ozone. However, the final CSAPR differed from CAIR in many ways. In a significant departure from past federal allowance trading programs, CSAPR only allowed for limited interstate trading. For example, the rule divided states into two groups for purposes of SO_2 allowance trading – Group 1 and Group 2. While trading was allowed within a given group, the rule prohibited trading across the two groups. For example, both Georgia and Alabama were part of Group 2; therefore, sources in those states could buy and sell SO_2 allowances with each other. However, North Carolina, Virginia, West Virginia, Pennsylvania, Ohio, Indiana and Illinois were all Group 1 states; therefore sources in Alabama and Georgia could not trade with sources in those states. In addition, like CAIR, CSAPR established SO_2 and NO_x emissions budgets for each affected state but CSAPR prohibited states from exceeding their state-wide budgets by more than a set percentage, referred to as the "variability limit." In other words, CSAPR was not an unlimited cap-and-trade program like CAIR. The final rule was structured as a Federal Implementation Plan (FIP). States had the option of adopting a State Implementation Plan (SIP), but not for initial compliance. CSAPR required unreasonable emission reductions by 2012, just six months after issuance of the final rule, with another significant reduction required for many states, including Georgia, starting in 2014. Figure 2.5-1 illustrates the states included in CSAPR. Alabama and Georgia were included in the annual SO_2, annual NO_X, and seasonal NO_X programs.

In addition to unreasonable deadlines and requirements, the final CSAPR contained numerous and significant errors. These underlying flaws, combined with the immediate nature of the rule, caused numerous states, industry organizations, and utilities to challenge the rule. In total, 45 petitions for review and/or petitions for stay were filed in the D.C. Circuit Court by industry petitioners, states, cities, and labor unions and 33 petitions for administrative reconsideration were filed with EPA. Southern Company and its subsidiaries filed both a petition for administrative reconsideration and a petition for judicial review. On December 30, 2011 – less than 48 hours before compliance requirements were set to begin, the D.C. Circuit Court stayed the rule pending resolution of the litigation and ordered EPA to continue administering CAIR in the interim.

On August 21, 2012, the D.C. Circuit vacated and remanded CSAPR and directed EPA to continue administering CAIR pending completion of a remand rulemaking to replace CSAPR with a valid rule. The court found that CSAPR "exceeds [EPA's] statutory authority in two independent respects" by (1) requiring upwind states to reduce emissions by more than their own significant contributions to nonattainment in other states, and (2) failing to allow states the initial opportunity to implement, through state implementation plans (SIPs), the emission reductions required by EPA in CSAPR.

Petitions for rehearing were filed in October 2012 and were denied by the court in February 2013. In March 2013, EPA submitted a request for Supreme Court review, and on June 24, 2013, the Supreme Court agreed to take the appeal. On April 29, 2014 the U.S. Supreme Court reversed the D.C. Circuit decision vacating CSAPR and remanded the case back to the D.C. Circuit court for further proceedings. While the D.C. Circuit stay of CSAPR remains in effect, EPA and other environmental petitioners have asked the D.C. Circuit to lift the stay. EPA has asked the court to toll the CSAPR compliance deadlines by three years, so that Phase 1 emissions budgets would apply beginning in January 2015 and Phase 2 emissions budgets would apply beginning in January 2017 and beyond. State, industry and labor petitioners have opposed lifting the stay. The court has not yet ruled on the motion. The timing and impact on future proceedings is unclear at this time.

In the meantime, EPA has begun working on a new interstate transport rule to address nonattainment issues associated with the 2008 ozone NAAQS. EPA's regulatory agenda indicates that a proposed rule is expected in October 2014, which could result in a final rule by October 2015. It is unclear at this time what emission reductions may be required by this transport rule. In the interim, EPA will continue to administer CAIR. CAIR Phase II is scheduled to begin in January 2015, and it is unclear at this time whether sources will be required to comply with CAIR Phase II or with CSAPR Phase I in January 2015.

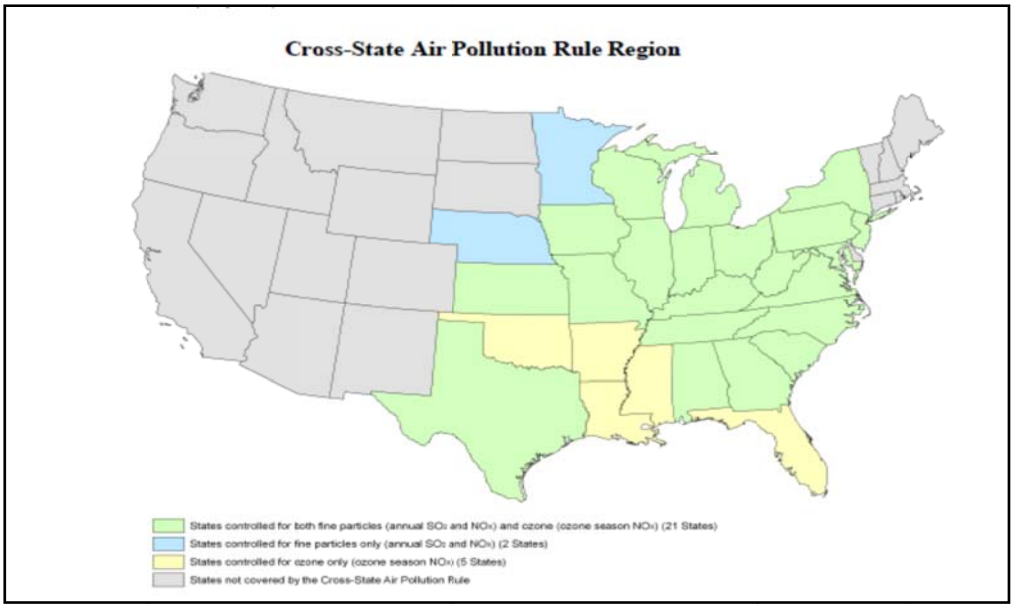


Figure 2.5-1 States Covered by the Final Cross-State Air Pollution Rule

2.6 Mercury and Air Toxics Standards (MATS)

EPA's Mercury and Air Toxics Standards (MATS), issued in final form in December 2011, is designed to reduce mercury, acid gases and certain metal emissions from coal- and oil-fired utility boilers. To do so, it establishes stringent emission limits based on Maximum Achievable Control Technologies (MACT) for hazardous air pollutants (HAPs). While the rule contains limited emissions averaging provisions, in general the limits must be met on a unit-by-unit basis and is thus known as a command -and -control type regulation.

Prior to developing the MATS rule, EPA had planned to take a market-based approach to achieve mercury reductions from coal-fired power plants. On March 15, 2005, EPA announced the final Clean Air Mercury Rule (CAMR), a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants as an alternative to MACT emission limits under Section 112 of the CAA. EPA concurrently delisted coal-fired power plants from CAA Section 112 in order to regulate them under Section 111 for CAMR. However, in February 2008, in response to a legal challenge to CAMR brought by a number of states and environmental groups, the D.C. Circuit Court of Appeals vacated CAMR and vacated EPA's concurrent rule to "delist" power plants from the CAA provisions that require application of MACT. The vacatur became effective on March 14, 2008, nullifying CAMR mercury emission control obligations and monitoring requirements. Petitions for rehearing filed by EPA and the Utility Air Regulatory Group (UARG) were denied on May 20, 2008, and both parties filed an appeal to the Supreme Court. EPA later withdrew its petition, and the Supreme Court denied UARG's petition on February 23, 2009.

In response to the vacatur of CAMR, EPA has issued MACT standards for coal- and oil-fired electric generating units (EGUs) under Section 112 of the CAA through the promulgation of the MATS rule. Unlike CAMR's cap and trade program, MATS is a technology-based command-and-control rule that addresses a number of hazardous air pollutants (HAPs), not just mercury.

On March 16, 2011, EPA signed the proposed MATS rule. The proposed rule covered both new and existing coal- and oil-fired electric utility steam generating units and required each unit to meet stringent emission limits for mercury, particulate matter (as a surrogate for certain metals), and acid gases. While all three categories of limits were very stringent, the particulate matter limit, in particular, included especially onerous compliance requirements. The proposed rule required units to not only comply with a standard numerical total particulate limit (filterable + condensable), but also required units to comply with unit-specific limits on filterable particulate matter. The unit-specific limits would be based on the actual emission test results during periodic steady-state testing, while the unit would then be required to maintain emissions below those achieved during steady-state testing at all times and during all modes of operation. These proposed requirements essentially removed all compliance margin built into existing controls without accounting for the natural variation in operation of a generating unit.

Numerous and significant concerns were raised over the stringency of the proposed emission limits and the ability to install the necessary control technologies by the compliance deadlines. Many industry, reliability organizations, and states filed comments on the rule suggesting that the results of this regulation could have a substantial impact on the reliability and affordability of electricity in the United States. In total, more than 150 industry comments were submitted on the proposed rule, and more than 27 states and 1 territory sought major changes or withdrawal of the rule.

On December 16, 2011, EPA signed the final MATS rule. The rule was published in the Federal Register on February 16, 2012, and became effective on April 16, 2012. The Clean Air Act specifies that MACT compliance for existing sources begins within 3 years after the effective date of the final rule with limited options for compliance extensions. Despite numerous requests for additional compliance time, EPA finalized the rule with a compliance deadline for existing sources of April 16, 2015. In a change from the proposed rule, however, EPA stated in the final rule supporting documents that the one-year case-by-case extension from the state permitting authority should be "broadly available" for units installing controls as well as for units that are in the process of being replaced or retired but that are necessary for maintaining system reliability. Also, the final MATS rule included a very limited option to seek an administrative order from EPA allowing up to an additional year for "reliability-critical" units beyond the 1-year extension available from state permitting authorities. However, EPA has set a high bar for this additional extension and has stated that it will not issue such orders until after the compliance deadline. While many provisions, such as the mercury and acid gas limits were largely unchanged from the proposed rule, EPA did make key changes in the particulate matter requirements that ultimately led to changes in the compliance strategy for Georgia Power. In the final rule, EPA changed the form of the particulate matter limit from the more uncertain total particulate matter to the more commonly and reliably measured filterable particulate matter and eliminated the requirement to have unit-specific operating limits.

For oil-fired units only, the final rule also contained a new option for “limited use” boilers that was not in the proposal. As a result, units that take an 8 percent capacity factor limit are not subject to the numerical emission limits but must fulfill various work practice requirements, including a periodic boiler inspection and tune-up. Many in industry had advocated for a limited use category for both oil and coal units, but none suggested a capacity factor limit nearly as low as finalized by EPA. Southern Company, on behalf of Georgia Power and other operating companies, had suggested a limited use category for oil and coal units with less than 30 percent capacity factor to preserve the flexibility and value of peaking units.

On April 16, 2012, Southern Company as well as UARG filed a petition for reconsideration of certain aspects of the final rule. UARG also filed a petition for judicial review with the D.C. Circuit Court. On June 28, 2012 the court severed the new source issues and ordered an expedited briefing schedule for those issues, which began on October 23, 2012. On November 30, 2012 EPA proposed a reconsideration of certain new source provisions and for startup and shutdown issues for existing sources. EPA completed its reconsideration rulemaking for new sources in April 2013, but has not acted on the existing source reconsideration. On April 15, 2014, the D.C. Circuit issued its opinion, denying all petitioners’ challenges to the MATS rule that were before the court. Industry groups and a coalition of twenty-three states have asked for Supreme Court review of this decision.

2.7 New Source Performance Standards for Criteria Pollutants

Recent EPA actions include revisions to two of the New Source Performance Standards (NSPS) affecting NOx and SO_2 emissions from various types of power plants. The impact of these rules is usually limited to new power plants, but can also impact existing plants under certain circumstances.

First, in conjunction with the MATS rulemaking, EPA released final revisions to the NSPS for Electric Utility Steam Generating Units in December 2011. The revisions included more stringent limits for NOx and SO_2 for new coal-fired power plants, as well as some minor revisions affecting compliance options for both existing and new plants subject to the rule.

Second, EPA proposed revisions to the NSPS for Stationary Combustion Turbines in August 2012. While the proposed revisions make few changes to the numerical NOx and SO_2 emission limits, EPA’s proposal would make some key changes to certain compliance demonstrations. For example, while the rule typically only applies to new power plants, EPA proposes to drastically change the way that projects at an existing unit must be evaluated to determine whether the unit has been “reconstructed,” thus triggering applicability of the rule. EPA’s proposed changes, if finalized, would greatly increase the risk that existing combined-cycle and combustion turbine power plants that are not currently subject to the NSPS for Stationary

Combustion Turbines could trigger the reconstruction test and become subject to more stringent requirements.

2.8 Industrial Boiler (IB) MACT

In February 2004, EPA finalized the Industrial Boiler (IB) MACT rule to impose limits on hazardous air pollutants from industrial boilers, including biomass-fired boilers used for electricity generation and start-up boilers. Compliance with the final rule was scheduled to begin in September 2007; however, in response to challenges to the final rule, the D.C. Circuit vacated the rule in its entirety in July 2007.

In response to the court's ruling, EPA began development of a new IB MACT. On April 29, 2010, EPA issued a proposed IB MACT rule and finalized the rule on February 21, 2011. The rule establishes different emissions limits for different subcategories of boilers, including natural gas-fired boilers, oil-fired boilers, biomass stoker boilers, and biomass fluidized bed boilers among others. The limits in the new IB MACT are much more stringent than the IB MACT that was vacated in 2007. Soon after issuance of the final rule, EPA announced plans to reconsider the final rule. The proposed reconsideration rule was published in the Federal Register on December 23, 2011, with many significant changes to the emission limits in the rule. EPA released the final reconsideration rule on December 21, 2012, which included some further changes from the proposed emission limits and requirements. As with previous revisions, some of the limits became less stringent but others became more stringent. In general, however, most limits affecting existing sources were improved or stayed the same. EPA also finalized changes to other compliance requirements, however, that must be analyzed for affected units on a case-by-case basis to determine the impacts. On January 31, 2013, the final reconsideration of the IB MACT rule was published in the federal register. Compliance for existing sources will begin 3 years after the final rule is published in the Federal Register, or January 31, 2016. Compliance for new sources will begin January 31, 2016, or upon startup, whichever is later. While the final rule published in January 2013 is less stringent than some previous versions released by EPA, there are still concerns over the stringency of the emission limits for many sources. On April 1, 2013, several petitions for reconsideration and petitions for judicial review were filed. A joint briefing schedule was proposed on November 25, 2013, with all briefs to be filed by June 27, 2014. Oral argument could occur in fall 2014.

2.9 Clean Air Visibility Rule (CAVR)

CAVR (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in specified "Class 1" areas (primarily national parks and wilderness areas) by 2064. The rule involves: (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977, and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, CAVR allowed states to determine that CAIR satisfied BART requirements for SO_2 and NOx.

Extensive studies were performed for each Georgia Power affected unit to demonstrate that additional PM controls are not necessary under BART. In 2010, the Georgia EPD submitted to EPA a regional haze SIP which includes the conclusion that CAIR was sufficient to address both SO_2 and NOx BART as well as Reasonable Progress for Georgia Power units, and that no additional PM controls are warranted under BART. In mid-2012, EPA took several actions relative to the Georgia Haze SIP. While EPA approved of many aspects of the Georgia SIP, it disapproved of the section that concluded CAIR was sufficient to meet SO_2 and NOx BART. EPA issued a federal implementation plan essentially replacing that portion of the SIP with CSAPR. However, subsequently the D.C. Circuit Court vacated CSAPR, creating some uncertainty on SO_2 and NOx BART requirements for the 21 affected Georgia Power units. The decision was appealed to the Supreme Court which accepted the case and overturned the vacatur on April 29, 2014 and remanded the case to the lower court for further proceedings.

In September and October of 2012, the National Parks Conservation Association (NPCA) and Sierra Club filed 10 petitions for review in seven circuits (including the D.C. Circuit) related to EPA actions around CSAPR and Regional Haze (CSAPR=BART) requirements. Most of the petitions were filed based on grounds arising from the CSAPR vacatur decision. NPCA and Sierra Club believe that all of the cases should be consolidated and heard in the D.C. Circuit, but have filed the petitions as a protective measure. There are existing petitions pending at the D.C. Circuit, including a UARG challenge to certain aspects of the EPA CSAPR=BART rule.

Among the 10 petitions is one filed in the 11th Circuit challenging the EPA rule that allows CSAPR to fulfill some regional haze requirements for the State of Georgia. The Georgia petition is the lone case in the 11th Circuit. On December 12, 2012 NPCA, et. al., moved to transfer the case to the D.C. Circuit Court of Appeals which was granted and subsequently consolidated with the UARG case mentioned above. The UARG case was then held in abeyance until the Supreme Court resolution of the CSAPR case. The cases continue to be held in abeyance, and motions to govern further proceedings are due October 15, 2014. 21 Georgia Power units were originally included in the Georgia Haze SIP for BART requirements and the analysis for those units could be affected by the outcome of this case.

2.10 Georgia Multipollutant Rule and Georgia SO_2 Emissions Rule

In response to both federal rules as well as state-specific objectives, the State of Georgia has implemented a set of state rules governing emissions from coal-fired power plants. The Georgia Multipollutant Rule was finalized in June 2007, while the Georgia SO_2 Emissions Rule was finalized in January 2009. Both rules require the installation and operation of certain emission controls on all of the larger coal-fired electric generating units in the state by specific dates.

The Georgia Multipollutant Rule was designed to reduce emissions of mercury, sulfur dioxide, and nitrogen oxides state-wide by requiring installation of specified control technologies at each affected unit by specific dates originally set between December 31, 2008, and June 1, 2015. This rule required the installation of SCRs for NO_X reduction and scrubbers for SO_2 reduction on the majority of Georgia Power's coal-fired units. The rule also required installation and operation of baghouses with sorbent injection at Plant Scherer for mercury control. If the emission control equipment is not installed and operating by the required date, the generating unit may not be allowed to continue operating.

The Georgia SO_2 Emissions Rule was designed to be a companion rule to the Georgia Multipollutant rule. The rule required reduction of SO_2 emissions by 95% from all units required to install scrubbers under the Georgia Multipollutant Rule, except Yates Unit 1 where a 90% reduction is required. The rule required compliance beginning in January 2010 for units with scrubbers in operation, and requires reductions from the remaining units at dates that align with or are close to the Multipollutant Rule compliance dates.

In June 2011, revisions to both the Georgia Multipollutant Rule and Georgia SO_2 Emissions Rule were approved by the Georgia Department of Natural Resources. These revisions moved up the scrubber and SCR compliance dates for Branch Units 1 and 2 and Scherer Unit 3. The revised rules also allowed for additional time to install the prescribed controls on Plant Branch Units 3 & 4 in an attempt to streamline the compliance deadlines in the state rules with the new MATS rule, which was not yet final at the time. This change would allow Plant Branch Units 3 and 4 to consider the MATS requirements in the design and construction process, as well as in the decision regarding whether to proceed with controls, at these units.

In April 2013, additional revisions to both the Georgia Multipollutant Rule and the Georgia SO_2 Emissions Rule were approved by the Georgia Department of Natural Resources. These revisions revised some of the compliance dates in the state rules to align with the MATS rule compliance dates. The revisions changed the compliance dates for Plant Branch by moving Unit 1 from October 1, 2013 to April 16, 2015 and Units 3 and 4 from October 1, 2015 and December 31, 2015, respectively, to April 16, 2015. The revisions also required Plant Yates Units 1 through 5 to convert to natural gas and allowed Yates Units 6 and 7 to either install SCRs and scrubbers or convert to natural gas, all by April 16, 2015. The Multipollutant Rule requirements, including these revisions, are shown in Table 2.10-1.

Table 2.10-1 Georgia Multipollutant Rule Requirements

Unit	Control Equipment	Installation & Operation Deadline
Bowen 3	SCR and FGD	December 31, 2008
Bowen 4	SCR and FGD	December 31, 2008
Hammond 1	FGD	December 31, 2008
Hammond 2	FGD	December 31, 2008
Hammond 3	FGD	December 31, 2008
Hammond 4	SCR and FGD	December 31, 2008
Wansley 1	SCR and FGD	December 31, 2008
Yates 1*	FGD	December 31, 2008
Bowen 2	SCR and FGD	June 1, 2009
Scherer 2	Sorbent injection in baghouse	June 1, 2009
Scherer 3	Sorbent injection in baghouse	June 1, 2009
Scherer 1	Sorbent injection in baghouse	December 31, 2009
Wansley 2	SCR and FGD	December 31, 2009
Bowen 1	SCR and FGD	June 1, 2010
Scherer 3	SCR and FGD	July 1, 2011
McDonough 2**	SCR and FGD	December 31, 2011
McDonough 1**	SCR and FGD	April 30, 2012
Branch 2**	SCR and FGD	October 1, 2013
Scherer 2	SCR and FGD	December 31, 2013
Scherer 1	SCR and FGD	December 31, 2014
Yates 1-5*	Natural Gas Conversion	April 16, 2015
Yates 6	SCR and FGD or Natural Gas Conversion	April 16, 2015
Yates 7	SCR and FGD or Natural Gas Conversion	April 16, 2015
Branch 1, 3, 4*	SCR and FGD	April 16, 2015

* Unit(s) are planned for retirement.
** Unit has been retired.

2.11 Startup, Shutdown and Malfunction (SSM) SIP Call

On February 12, 2013, EPA signed a proposed SIP Call that would require 36 states (including all of Region 4) to revise their SSM rules because they purportedly are inconsistent with the Clean Air Act and EPA policy. The Sierra Club petitioned EPA to take this action, primarily based on the arguments that such provisions allow emissions that could cause or contribute to violations of ambient air quality standards, and that they interfere with or preclude enforcement by agencies and citizens.

Comments on the proposed rule, due by May 13, 2013, were submitted by numerous industry groups, state agencies and state attorneys general opposing the proposal. Southern Company submitted substantial comments on the proposal, articulating concerns over the lack of consideration by EPA that the rule would impose a significant burden on states and regulated sources with no appreciable environmental benefit.

On June 16, 2014, the EPA entered into an agreement with environmental petitioners that requires the EPA to issue a supplemental proposed action on Sierra Club's petition by September 5, 2014, and to take final action by May 22, 2015.

2.12 GHG Policies, GHG Emissions, and Renewable/Clean Energy Standards

GHG and Renewable/Clean Energy Legislation

Over the past several years the U.S. Congress has considered many proposals to reduce GHG emissions and mandate renewable or clean energy. These proposals have taken many forms, for example: a cap-and-trade program, carbon tax, and renewable/clean energy standards. In the past few years, there have been many bills brought to the legislative floor which include the cap-and-trade bill "Waxman-Markey", the "Sanders-Boxer" carbon tax bill, and Senator Bingaman's "Clean Energy Standard Act" that attempted to set a clean energy standard. The introduction of the "Sanders-Boxer" carbon tax (also known as the Climate Protection Act of 2013) in February 2013 was the only significant GHG-related legislative activity occurring in 2013. "Sanders-Boxer" proposes an upstream tax on carbon emitting substances equal to $20 per metric ton of CO_2 and methane equivalent. The tax, starting in 2014, would escalate annually at about 4% above inflation. Sixty percent of the revenues generated would be redistributed to provide monthly residential rebates to legal U.S. residents. The remaining revenues would be placed in a fund to be used for: mitigating the economic impacts on energy-intensive and trade-exposed industries; low-income weatherization assistance; clean energy job training and education; Advanced Research Projects Agency-Energy (ARPA-E), and Federal budget debt reduction. To date, Congress has declined to pass legislation to address climate change.

Global Climate Change – International

International climate change negotiations under the United Nations Framework Convention on Climate Change (UNFCCC or Convention) continue. Since 2005, the Convention has established various "working groups" to address key issues and negotiate future climate-related international agreements. The Working Groups meet periodically throughout the year and, along with the formal subsidiary bodies to the Convention, again at the annual Conference of Parties (COP) and a Meeting of the Parties to the Kyoto Protocol (CMP). The COP is the supreme decision-making body of the Convention, which reviews the implementation of the Convention and other legal instruments. The CMP reviews the implementation of the Kyoto Protocol. To date, there have been 19 COPs and 9 CMPs.

COP 15 / CMP 5 in Copenhagen, Denmark in 2009 yielded an informal nonbinding political agreement known as the Copenhagen Accord. The Copenhagen Accord included, among other things, a process for countries to enter their nonbinding mitigation pledges. More than 130 countries associated themselves with the Copenhagen Accord and more than 80 countries, including the United States, made nonbinding greenhouse gas mitigation pledges. The U.S agreed to reduce greenhouse gas emissions by 17% from 2005 levels by 2020.

During COP 16 / CMP 6 in 2010 in Cancun, Mexico, the Parties sought to develop a series of decisions that expanded upon the basic framework set forth in the Copenhagen Accord. The Cancun Agreements took the initial steps to implement the operational elements of the Copenhagen Accord.

The COP 17 / CMP 7 meetings took place in Durban, South Africa in 2011. These meetings resulted in the Durban Platform for Enhanced Action, a negotiating process seeking to yield a legally binding emission reduction program applying to all countries by 2016, to enter into force in 2020.

COP 18 / CMP 8 took place in Doha, Qatar in 2012. These negotiations resulted in a plan of action to develop the legally binding emission reduction program by the end of the 2015 negotiations as required by the Durban Platform. Also, a second commitment period under the Kyoto protocol was established that will run from January 1, 2013, to 2020. The United States is not part of the second commitment period since it is not a party to the Kyoto Protocol.

COP 19 / CMP 9 took place in Warsaw, Poland in 2013. Parties decided to initiate preparation for their intended emission reduction contributions towards the Durban Platform, which will come into force in 2020. Parties will submit reduction plans in advance of COP 21 and by the first quarter 2015.

COP 20 / CMP 10 are scheduled for December 2014 in Lima, Peru. COP 21 / CMP 11 are scheduled for November – December 2015 in Paris, France.

Greenhouse Gas Regulation - Background

In April 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles and that EPA must decide whether these emissions endanger public health and welfare. In December 2009, EPA published a final determination, which became effective on January 14, 2010, that certain greenhouse gas emissions from new motor vehicles endanger public health and welfare. On April 1, 2010, the EPA issued a final rule regulating greenhouse gas emissions from new motor vehicles under the Clean Air Act. EPA took the position that once this rule went into effect on January 2, 2011, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants. As a result, the construction of new facilities or the major modification of existing facilities could trigger the requirement for a PSD permit and the installation of the best available control technology for carbon dioxide and other greenhouse gases.

On May 13, 2010, the EPA issued a final rule, referred to as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. In accordance with the Tailoring Rule, as of January 2, 2011, new and modified sources that have GHG emissions over the thresholds (100,000 tons per year (tpy) for new sources and increases over 75,000 tpy for existing sources) must go through the prevention of significant deterioration (PSD) permitting process including installation of the best available control technology (BACT) for CO_2 and other GHGs.

These greenhouse gas regulations have been litigated. On December 10, 2010, the D.C. Circuit denied the motions for a stay of EPA's GHG rules, which had been filed by Texas and a number of industry petitioners. The challenges to the reconsideration of the Johnson Memo and the Tailoring Rule were consolidated so there were three cases involving EPA's GHG rules before the U.S. Circuit Court of Appeals for the District of Columbia. On June 26, 2012, the Court upheld these EPA rules. All petitions to review were dismissed or denied.

On Oct. 15, 2013 the Supreme Court agreed to review one narrow but important issue: "whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit greenhouse gases." On June 23, 2014 the Supreme Court ruled that:

- The EPA cannot require prevention of significant deterioration (PSD) or Title V permitting solely on the basis of GHG emissions.
- The EPA cannot "tailor" the CAA's unambiguous permitting thresholds.
- For large facilities that are already required to apply for PSD permits because of conventional air emissions ("anyway sources"), EPA can require those applicants to undertake a "best system of control technology" (or BACT) analysis if they emit GHGs above a de minimis amount.
- Even for those facilities that must obtain PSD permits anyway and become subject to GHG BACT, the Court reminded EPA of the limits on its authority. For example , the BACT analysis must take into account energy, economic, and environmental considerations, and may not require redesign of a facility or even require reductions in demand for electricity from the grid.

On July 20, 2011 EPA published a final rule that defers for a period of three years GHG permitting requirements for CO2 emissions from biomass-fired and other biogenic sources under the PSD and Title V programs. Groups challenged EPA's three-year deferral, and on July 12, 2013 the D.C. Circuit Court vacated the three-year deferral. While the Court withheld the issuance of its "mandate," and the decision did not become final, the three-year deferral rule expired by its own terms in July 2014.

CO_2 Regulation – Performance Standards

On April 13, 2012, EPA published its proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units rule (also known as the GHG New Source Performance Standard or NSPS) in the Federal Register. Given the date of the proposal, a final rule for the GHG NSPS was required by April 13, 2013, but EPA missed this deadline. On Sept. 20, 2013, EPA issued a new proposed rule and, in a separate action, proposed to withdraw the original proposal. The re-proposal applies only to new fossil fuel-fired electric generating units and does not apply to modified, reconstructed, or existing units. According to this re-proposal, new natural gas combined cycles and potentially simple cycle combustion turbines (depending on a three-year rolling capacity factor) must not exceed 1,000 pounds of CO_2 per gross megawatt hour for combustion turbines greater than 250 MW and 1,100 pounds of CO_2 per gross megawatt hour for combustion turbines of greater than 73 MW but less than or equal to 250 MW. New coal and oil-fired utility boilers and integrated gasification combined cycle units must not exceed 1,100 pounds of CO_2 per gross megawatt hour. In the re-proposal, EPA determined that the best system of emission reduction (BSER) that has been adequately demonstrated for natural gas combined cycle units is modern, efficient combined-cycle design. BSER for boilers and IGCCs is implementation of partial CCS. This rule potentially impacts the operational flexibility of new natural gas combined-cycle units and effectively eliminates new coal-fired electric generation without carbon capture and storage. This proposal was published in the Federal Register on January 8, 2014. Southern Company submitted comments on the proposal to EPA on May 9, 2014. The Clean Air Act requires the proposed GHG NSPS to be finalized by January 8, 2015.

On June 25, 2013, President Obama announced his Climate Action Plan designed to reduce emissions of GHGs and take additional steps to mitigate and adapt to climate change. At the same time, he released a White House memorandum on "Power Sector Carbon Pollution Standards" that directed EPA to propose standards, regulations, or guidelines for modified, reconstructed, and existing fossil-fired electric generating units by June 1, 2014. The memorandum required those regulations to be finalized by June 1, 2015 and directed EPA to require states to develop and submit plans to implement EPA's existing source guidelines by June 30, 2016.

Consistent with the President's directive, on June 2, 2014, EPA issued its Clean Power Plan – specifically, guidelines for state reduction of CO_2 emissions from existing fossil fuel fired electric generating units. The proposed existing source guidelines set aggressive state-specific CO_2 emission targets that must be achieved by 2030 with interim goals starting in 2020. EPA's proposal relies on plant and demand side efficiency measures, redispatch of generation sources, and employment of renewables at unprecedented levels and also steps outside of the Clean Air Act through its reliance on measures that would be employed outside of the power plant unit. EPA has also proposed CO_2 performance standards for modified and reconstructed sources in a separate rule issued on the same day. EPA has provided 120 days from publication for public review of both rules, and comments are due by October 16, 2014. Both rules are scheduled to be finalized by June 1, 2015, and states must submit plans to implement the existing source guidelines by June 30, 2016 consistent with the President's memorandum. States may however, request a one or two year extension under certain circumstances.

GHG Reporting Rule

EPA's mandatory GHG Reporting Rule (40 CFR Part 98) was developed as the result of legislation passed by Congress in 2008, authorizing the EPA to "collect accurate and timely greenhouse gas data to inform public policy decisions." The Rule was finalized in October 2009 and requires annual reporting of GHG emissions beginning with calendar year 2010 for CO_2, methane, nitrous oxide, and most fluorinated gases. The Rule applies to facilities that emit 25,000 metric tons a year or more of CO_2 equivalent, which includes all of Georgia Power's fossil fuel-fired generating plants. In addition, the rule requires sulfur hexafluoride (SF_6) emissions, which may be emitted from transmission and distribution equipment, to be reported beginning with calendar year 2011.

2.13 Water Issues

316(b) Regulations

Section 316(b) of the CWA requires that the location, design, construction, and capacity of any cooling water intake structure (CWIS) reflect best technology available for minimizing adverse environmental impact. Historically NPDES permit writers have applied Section 316(b) on a case-by-case basis. In 2004, EPA published final technology-based regulations under Section 316(b) of the CWA for the purpose of reducing impingement and entrainment of fish, shellfish and other forms of aquatic life at existing power plant CWISs. In January 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule, including the use of cost-benefit analysis, to the EPA for revision. As a result, EPA withdrew the new rule and began developing a new proposal. In April 2009, the U.S. Supreme Court reversed the Second Circuit's decision with respect to the rule's use of cost-benefit analysis, and held that the EPA could consider costs in arriving at its standards and in providing variances from those standards for existing power plant CWISs.

On March 28, 2011, pursuant to a settlement agreement with environmental groups, EPA signed and released a new 316(b) proposal. EPA published two Notices of Data Availability (NODAs) in the *Federal Register* in June 2012. In the first NODA, EPA requested comment on possible alternative approaches to the impingement mortality control requirements that EPA was considering for the final rule. In the second NODA, EPA asked for comment on the Stated Preference Survey (willingness-to-pay survey) which EPA was conducting to help quantify the "benefits" of the rule. Southern Company submitted comments on both of the NODAs in July 2012.

On May 19, 2014 EPA signed the final 316(b) rule. Existing facilities that withdraw at least 25 percent of their water from an adjacent water body exclusively for cooling purposes and have a design intake flow of greater than 2 million gallons per day are required to reduce fish impingement. Seven options for meeting best technology available requirements for reducing impingement are available. Facilities that withdraw at least 125 million gallons per day are required to conduct studies to aid the permitting authority to determine which site-specific entrainment mortality controls, if any, will be required. New units at an existing facility that are built to increase the generating capacity of the facility will be required to reduce the intake flow to a level similar to a closed cycle, recirculating system. This can be done by incorporating a closed-cycle system into the design of the new unit, or by making other design changes equivalent to the reductions associated with closed-cycle cooling. Furthermore, the EPA has concluded its Endangered Species Act consultation with the Fish and Wildlife Service and the National Marine Fisheries Service. The final rule establishes a process whereby the Services will be provided an opportunity to review permit applications of each facility seeking compliance with 316(b) of the CWA, either during a section 7 consultation with EPA or during review of every permit application submitted to a State or Tribe, and to analyze impacts to federally-listed species and designated critical habitat that may result from operation of the facility's CWIS. During this review, the Services will have an opportunity to recommend control measures, monitoring, and reporting recommendations on a site-specific and species-specific basis that will minimize adverse effects of CWIS operations. Compliance with the rule is to be determined by the permitting authority based on an "as soon as practicable" criterion. The final rule was published in the Federal Register on August 15, 2014 and will be effective October 14, 2014.

Effluent Limitations Guidelines Revision

On September 15, 2009, EPA announced its plans to commence a rulemaking to revise the current effluent guidelines for steam electric plants (ELG). The current rule, which was promulgated in 1982, establishes technology-based effluent limitations for new and existing discharges. EPA completed a multi-year study of power plant wastewater discharges and concluded that pollutant discharges from coal-fired power plants will increase significantly in the next few years as new air pollution controls are installed. EPA's study concludes that technologies are available to significantly reduce pollutant loadings from ash transport water and flue gas desulfurization (FGD also commonly referred to as "scrubber") wastewater.

During the data collection phase of this rulemaking, EPA sent a lengthy and comprehensive Information Collection Request (ICR) to 733 facilities seeking technical and economic data about FGD wastewater, ash handling, metal cleaning wastes, surface impoundments, wastewater treatment, and landfill operations. In addition, EPA has completed a separate wastewater sampling program covering several facilities around the country. This sampling effort focused on the evaluation of several FGD wastewater treatment systems (e.g., physical, chemical, and biological processes) in the removal of nutrients, mercury, and metals. EPA also sampled wastewater from two IGCC facilities and from a pilot-scale carbon capture study.

The proposed ELG was published on June 6, 2013 with comments due by September 20, 2013. Pursuant to a consent decree, EPA has agreed to finalize the rule by September 30, 2015. It will set internal limits requiring implementation of new technologies to treat certain wastewater streams. EPA's primary focus is on wastewater from coal-fired plants – FGD wastewater, ash transport water (both fly ash and bottom ash), ash pond and landfill leachate, and flue gas mercury control wastes; however, the Agency proposed to revise the limits on nonchemical metal cleaning wastes which will impact all steam electric facilities and proposed new limits on gasification wastewater.

Thermal Variances

In recent years, federal and state environmental protection agencies have voiced concerns about whether Section 316(a) variances can be justified in light of alleged impacts to fish and wildlife. With the retirement of Plant Branch in 2015, Georgia Power no longer will have any plants with a thermal variance.

Water Quality and TMDLs

Water quality standards are set by state law on toxics and other potential pollutants based on the protection of aquatic life and human health. The standards are in-stream standards, which are used to set water quality-based permit limits. To meet these and other limits, additional wastewater treatment, such as physical/chemical and/or biological systems, may be needed due to FGD wastewater impacts.

In addition, states are under increasing pressure to identify impaired waters (waters that do not meet applicable water quality standards), develop total maximum daily loads (TMDLs) for those waters, and impose point and non-point source controls designed to bring the waters into compliance. A TMDL is a calculation of the maximum amount of a pollutant that a water body can receive and still safely meet water quality standards. In developing TMDLs, the states have the responsibility to establish reasonable, scientifically sound allocations and divide the estimated pollutant loads equitably among non-point and point sources, such as utilities. These technical documents are driven by water quality standards and often impose strict effluent limitations.

Waters of the United States

On March 25, 2014 EPA and the Corps of Engineers released their proposed rule defining “waters of the United States” (WOUS) under the Clean Water Act. The proposed WOUS rule was published in the Federal Register on April 21, 2014 with a 90-day comment period, ending on July 21, 2014; however, EPA granted an extension of the comment period to October 20, 2014, in response to several requests. The proposed rule replaces the definition of “waters of the United States” as used in all Clean Water Act regulatory programs. The proposed rule would, among other things, expand the definition of a “tributary” and the definition of “adjacent waters” –both of these categories would be jurisdictional by rule. The proposed rule would also define “other waters” and subject these waters to a case-by-case “significant nexus” analysis to determine whether they are jurisdictional and subject to CWA regulations. If finalized as proposed, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges.

2.14 Land Issues

Coal Combustion Byproducts (CCR)

In May 2000, EPA concluded, after nearly 20 years of study, that coal ash does not warrant hazardous waste regulation under Resource Conservation and Recovery Act (RCRA) Subtitle C and that states should continue to be the primary environmental regulators for coal ash management.

A December 2008 release of ash from TVA's Kingston coal-fired generating facility resulted in increased scrutiny and focus on CCR management industry-wide. EPA issued Information Collection Requests (ICR) on the Structural Integrity of Coal Combustion Residuals in Surface Impoundments to electric utilities having surface impoundments that contain CCRs in March of 2009. Georgia Power responded to the EPA with information regarding ash ponds for all of its facilities. In addition, in 2009 and 2010, EPA inspected the ash pond dams for structural integrity at most of Georgia Power's facilities with ash ponds.

In June 2010, EPA issued a proposal for regulating the management and disposal of CCRs. EPA presented two separate regulatory options under RCRA for regulating CCRs when generated from coal-fired electric generating facilities: first, regulation as if the materials were a hazardous waste and second, regulation as a solid waste. Adoption of either option could require closure of, or significant change to, existing wet storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under the hazardous waste option, the EPA proposes to exempt certain beneficial reuses of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could still limit or eliminate beneficial reuse options. Georgia Power currently operates 11 electric generating plants with on-site coal combustion byproduct storage facilities (some with both "wet" (ash ponds) and "dry" (landfill) storage facilities). In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. In 2013, Georgia Power recycled over half of all coal combustion byproducts generated for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and Georgia Power has a routine and robust inspection program in place to ensure the integrity of its coal combustion byproducts surface impoundments and compliance with applicable regulations.

EPA continues preparation of a final rule for the management of CCR surface impoundments and landfills. Recently, multiple lawsuits were brought against EPA by environmental groups and end-use marketers to force EPA to review and revise, as necessary, regulations under RCRA, specifically those associated with CCRs. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of CCRs. On September 30, 2013, the U.S. District Circuit for the District of Colombia issued an order granting partial summary judgment to the environmental groups and other parties, ruling that the EPA has a statutory obligation to review and revise, as necessary, the federal solid waste regulations applicable to CCRs. On January 29, 2014, the EPA filed a consent decree requiring the agency to take final action regarding the proposed regulation of CCRs as solid waste by December 19, 2014. In addition to the EPAs rulemaking for CCRs, Congress has made multiple attempts to pass coal ash legislation, but these attempts have been unsuccessful to date.

GPC's coal combustion byproduct management practices are in compliance with the State of Georgia's regulatory requirements. GPC will continue to comply with all existing and future state and federal regulatory requirements and is continually seeking to increase appropriate beneficial use of coal combustion byproducts that it generates.

2.15 Major Litigation Matters

New Source Review

NSR is a pre-construction permitting program under the CAA that applies to changes to an emissions source (*e.g.*, electric generating unit) that result a "significant" increase of a regulated NSR pollutant.   Any new changes to NSR regulations or new interpretations of existing regulations could impact the methods utilized by the Company to ensure compliance and could have significant impact on unit operations. The Company has been actively participating in various legislative, regulatory, and judicial proceedings addressing NSR issues.

In 1999, EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by Mississippi Power, and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by Gulf Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The court quickly dismissed the claims against Alabama Power and declined to add claims against Mississippi Power and Gulf Power because the claims were improperly brought in Georgia. The case against Georgia Power (including claims related to the unit co-owned by Gulf Power) was administratively closed in 2001 and has not been reopened. To date, EPA has not re-filed its NSR claims against Mississippi Power or Gulf Power; however it has sought additional information from both companies on their NSR compliance status.

<u>United States v. Alabama Power</u>

After Alabama Power was dismissed from the original action, the EPA filed a separate action in January 2001 against Alabama Power (including claims related to the unit co-owned by Mississippi Power) in the U.S. District Court for the Northern District of Alabama. In the separate action against Alabama Power in the U.S. District Court for the Northern District of Alabama, Alabama Power settled certain claims in June 2006 to resolve the portion of the lawsuit related to Plant Miller. With respect to all other claims, Alabama Power prevailed on the merits – on March 14, 2011, the district court granted Alabama Power's motion for summary judgment on all remaining claims and dismissed the case with prejudice. The court ruled that the EPA could not prove Alabama Power should have predicted an emission increase following the projects at issue because the emissions methodology EPA had presented to the court was flawed. The EPA and the Alabama Environmental Council then appealed the court's decision to the U.S. Court of Appeals for the Eleventh Circuit.

On September 19, 2013, the Eleventh Circuit affirmed in part and reversed in part the district court's dismissal of EPA's complaint. In a 2-1 decision (District Court Judge William T. Hodges dissenting), the Eleventh Circuit affirmed the district court's decision striking the additional statements and calculations contained in an expert's supplemental declaration, but reversed the district court's exclusion of expert testimony related to the emissions increase calculations. The Eleventh Circuit denied Alabama Power's petition for rehearing and rehearing en banc on December 16, 2013 and remanded the case back to the N. D. of Alabama for further proceedings.

Carbon Dioxide Litigation

Connecticut v. AEP

In 2004, eight states and three environmental groups filed a nuisance suit against Southern Company and four other electric power companies seeking reductions in the companies' emissions of greenhouse gases. In September 2005, the U.S. District Court for the Southern District of New York dismissed the case on the grounds that the global warming issues of the case "present non-judiciable political questions that are consigned to the political branches, not the Judiciary." The plaintiffs appealed that decision to the U.S. Circuit Court of Appeals for the Second Circuit and, on September 21, 2009, the Second Circuit reversed the district court's ruling, vacating the dismissal of the plaintiffs' claim, and remanding the case to the district court.

After unsuccessfully requesting a rehearing en banc before the Second Circuit, defendants appealed the case to the United States Supreme Court. On June 20, 2011, in a unanimous decision, the Supreme Court overturned the Second Circuit's decision, holding that the plaintiffs' federal common law nuisance claims against the utilities were displaced by the Clean Air Act and EPA regulations addressing greenhouse gas emissions, and the Court remanded the case for consideration of whether federal law may also preempt the remaining state law claims. On September 2, 2011, the plaintiffs filed a motion to dismiss the appeal and the underlying case. On October 6, 2011, the U.S. Court of Appeals for the Second Circuit granted the plaintiffs' motion to remand the case to the district court for voluntary dismissal. The district court dismissed the case in December 2011. The case is now concluded.

Native Village of Kivalina v. Exxon Mobil Corp

In February 2008, the Native Village of Kivalina and the City of Kivalina (Alaska) filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that their village is being destroyed by erosion related to global warming caused by the defendants' emissions of greenhouse gases. The plaintiffs assert claims for public and private nuisance, under both state and federal law, and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. On September 30, 2009, the district court granted the defendants' motions to dismiss the case based on lack of jurisdiction and ruled that the claims were barred by the political question doctrine and by the plaintiffs' failure to establish the standard for determining that the defendants' conduct caused the injury alleged. The plaintiffs appealed the decision to the U.S. Court of Appeals for the Ninth Circuit, but the case was stayed by the Ninth Circuit in February 2011, pending the decision of the Supreme Court in Connecticut v. AEP. As noted above, the Supreme Court decision was issued on June 20, 2011 in favor of the defendant companies, and the plaintiffs in Kivalina have moved to lift the stay on their Ninth Circuit appeal and have requested the opportunity to submit supplemental briefing regarding the effect of the Supreme Court's decision. On August 31, 2011, the court granted the plaintiffs' motion to lift the stay. On September 21, 2012, the 9th U.S. Circuit Court of Appeals in San Francisco upheld the trial court's dismissal of Kivalina v. Exxon. The plaintiffs filed a petition for the 9^{th} Circuit Court to rehear the case on October 4, 2012. The petition was denied on November 27, 2012. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. The Supreme Court denied the petition for writ of certiorari on May 20, 2013. The petitioners' deadline to seek rehearing with the Supreme Court expired on June 14, 2013. The case is now concluded.

Comer v. Murphy Oil

On April 18, 2006, several plaintiffs sued Southern Company and a number of oil, gas, coal, and utility companies in the U.S. District Court for the Southern District of Mississippi seeking damages resulting from Hurricane Katrina. Because the plaintiffs named Southern Company instead of its individual operating companies, Southern Company was dismissed from the case, and the plaintiffs' motion to add the operating companies was not acted upon before the entire case was dismissed by the district court in 2007 based on the plaintiffs' lack of standing and the political question doctrine. Plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit, and a three-judge panel of the Fifth Circuit reversed the district court decision on October 16, 2009, holding that the plaintiffs did have standing to assert their nuisance, trespass, and negligence claims and that none of the claims were barred by the political question doctrine. On May 28, 2010, however, the Fifth Circuit dismissed the plaintiffs' appeal of the case on procedural grounds, reinstating the district court decision in favor of the defendants. On January 10, 2011, the United States Supreme Court denied the plaintiffs' petition to reinstate the appeal, ending the case.

However, on May 27, 2011, the same plaintiffs filed a new class action complaint in the same district court involving substantially similar allegations. The current litigation names operating companies Alabama Power, Georgia Power, Gulf Power and Southern Power, and includes many of the other same defendants that were involved in the earlier case. On March 20, 2012, the lawsuit was dismissed, with the U.S. District Court for the Southern District of Mississippi concluding that all of the claims made were barred because they had already been adjudicated in the earlier case, that the plaintiffs did not have standing because their alleged injuries were not fairly traceable to the defendants' conduct, and that all of the plaintiffs' claims were preempted by the Clean Air Act. On April 16, 2012, the plaintiffs appealed the dismissal of the case to the U.S. Court of Appeals for the Fifth Circuit. On May 14, 2013, the U.S. Court of Appeals for the Fifth Circuit upheld the U.S. District Court for the Southern District of Mississippi's dismissal of the case. This case is now concluded.

2.16 Other Considerations

Currently, there are no proposed regulations relating to lead that may have an effect on the installation of equipment or changes in the operation of electric generating plants. In addition, ECS-Appendix C provides an overview of existing and proposed regulations in regards to low-level and high-level nuclear waste. Southern Company will continue to monitor these issues and evaluate its strategy as changes occur.

3.0 Environmental Strategy

Based on the extensive regulatory and legislative issues described above, Georgia Power has developed a comprehensive compliance strategy designed to provide reasonable, cost-effective plans to comply with environmental requirements. Where appropriate, Georgia Power's strategy considers efficiencies that may be gained through strategy planning with other Southern Company affiliates. Georgia Power and Southern Company completed an initial environmental strategy following the passage of the 1990 Clean Air Act Amendments and established an annual, essentially on-going, process to develop, review, and update environmental compliance strategies using sophisticated, state-of-the-art analytical tools. The process has evolved and been refined over the years and has adapted to the changing regulations, but the goal is to produce least-cost compliance strategies that will minimize the impact on customers while achieving environmental objectives and assuring compliance with all requirements. This environmental planning or strategy process is illustrated in the figure below (Fig. 3-1). The strategy is essential for internal decision making and communication.

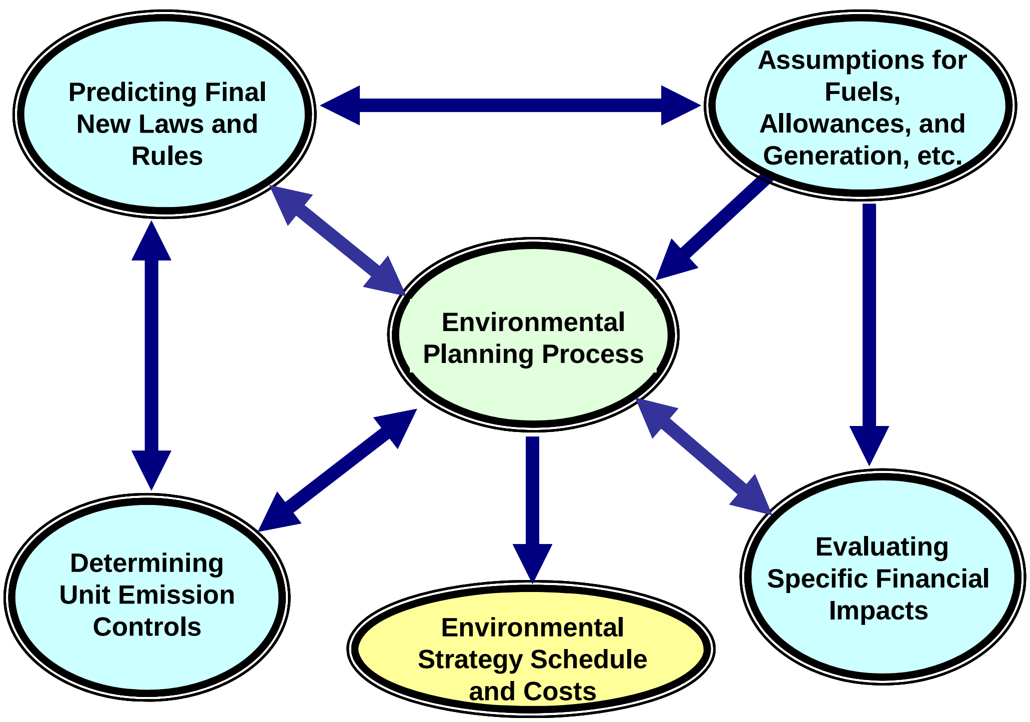


Figure 3-1 Annual Environmental Strategy Development Process for Existing Generation Retrofits

3.1 Strategy Process

The process for developing the environmental compliance plan includes the comprehensive involvement of a number of organizations within the company, including environmental, governmental affairs, planning, fuels, engineering, finance, operations, communications, generating plants, and research groups. This integrated process includes four steps as discussed below.

1. **Predicting and integrating the outcome of new environmental requirements**. The first step involves gathering all available knowledge about current and possible future local, state, regional, and national environmental requirements. The future requirements may be in the form of legislation that will need future rulemakings or in the form of draft or proposed new rules that must go through the rulemaking process to become final. Some rules may be part of an allowance-based cap and trade program over a regional or national scale and others may be local or state requirements that mandate specific requirements on specific plants. For many rules, the possibility that litigation will result in changes to the rule creates additional uncertainty.

2. **Developing assumptions on national, Southern Company, and Georgia Power Company levels.** In order to predict the impacts of the requirements on the generating plants, the company must make assumptions to predict generating unit, Georgia Power, Southern Company, and national electric system responses to existing and future environmental requirements (in addition to growing demands for electricity). These assumptions include:

    - Unit operating characteristics such as heat rates, capacity, and emission rates.
    - Fuel characteristics and costs, including natural gas, coal, and oil.
    - Allowance prices for cap and trade programs.
    - Control technology options and costs.
    - Future generation demand.

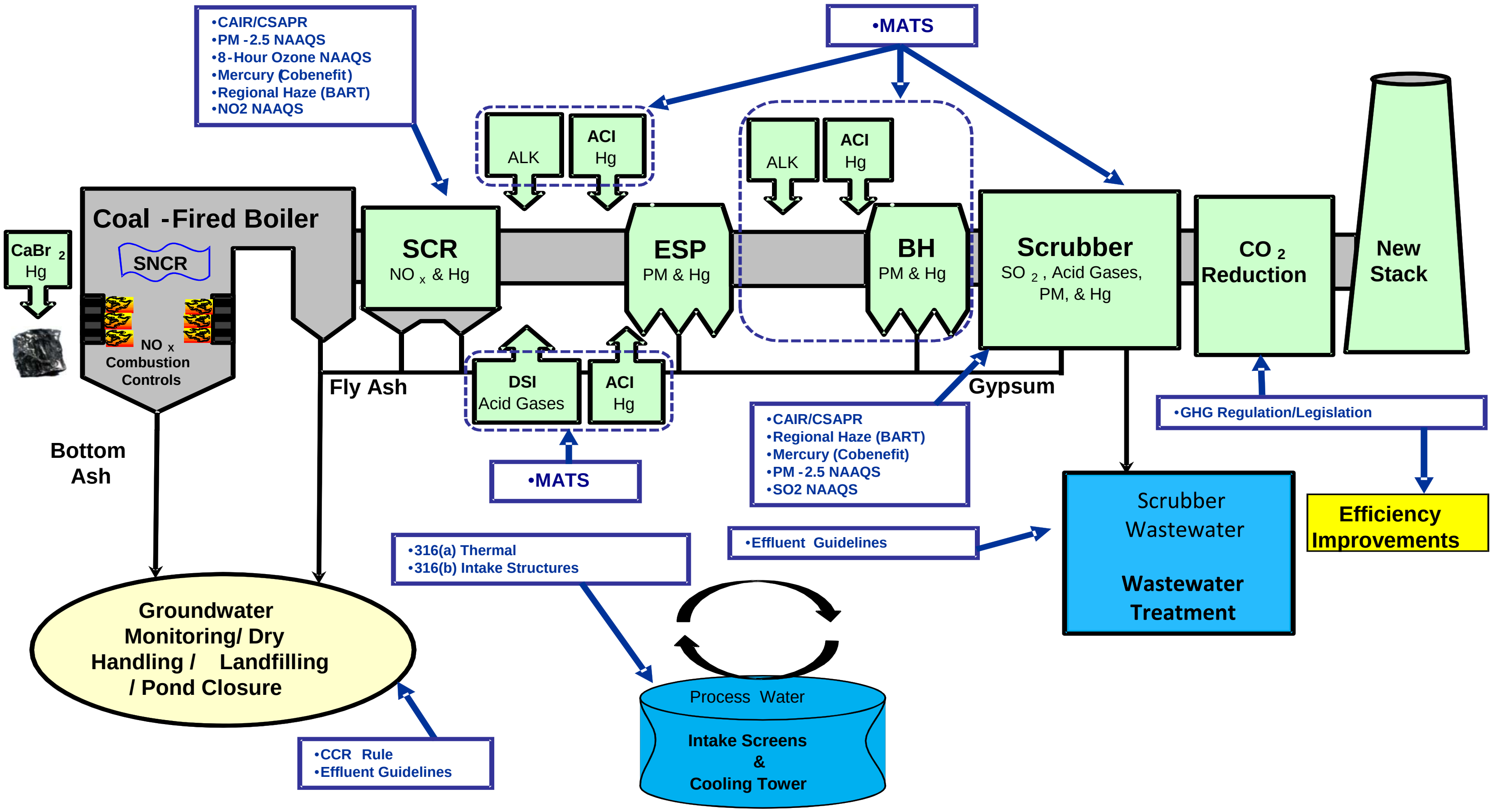
    To appropriately consider future legislative and market uncertainty, a scenario planning process was employed for long-term resource planning. A range of planning scenarios were developed and modeled as a part of the company's Integrated Resource Plan (IRP) Process. This range was established through the work of a coordinated planning team consisting of internal and external subject matter experts and company planning managers. The planning scenarios identify two fundamental dimensions that affect the range of potential futures for the electric utility industry – 1) fuel market demand and supply fundamentals and 2) GHG policy.

3. **Application of generating unit-specific cost-effective control technology options.** The application of control technology is dictated initially by the anticipated environmental requirements for each specific generating plant and/or unit. In some cases, the plant or

unit's emission control requirements are mandated, such as a plant-specific limit to meet local air quality requirements. In some cases, such as the cap and trade program for SO_2 established to address acid rain, utilities can choose the most cost-effective option: fuel switching, applying control technology, or purchasing emission allowances. The decision process reviews the cost-effectiveness of each of these options for each unit. Several of the most important emission control technologies for Southern Company compliance are described in the technology review discussion below.

The availability of control technology options varies by pollutant, as well. For example, when complying with SO_2 reduction requirements, the choices are basically fuel switching to lower sulfur coal, installing scrubbers, or buying allowances. Scrubbers are also effective for the reduction of fine particulates and mercury. For NO_X control, there are more control technology options available, such as low-NO_X burners, selective catalytic reduction, and selective noncatalytic reduction. Mercury emissions can be reduced through co-benefits from the combined operation of an SCR and a scrubber, injection of activated carbon with or without alkali sorbents, and injection of chemical additives to the coal upstream of the boiler. A fabric filter technology such as COHPAC or a baghouse may be necessary for fine particulate and/or mercury reduction at some units. The cost, control effectiveness, and operational issues of each technology for each generating unit must be considered. The figure below (Fig. 3.1-1) illustrates various control technologies and applications.

Figure 3.1-1 Possible Emission Control Technologies for Coal-Fired Boilers



All of these considerations are taken into account in developing a unit-specific decision on the application of emissions control technologies. The figure below (Fig. 3.1-2) illustrates this decision process.

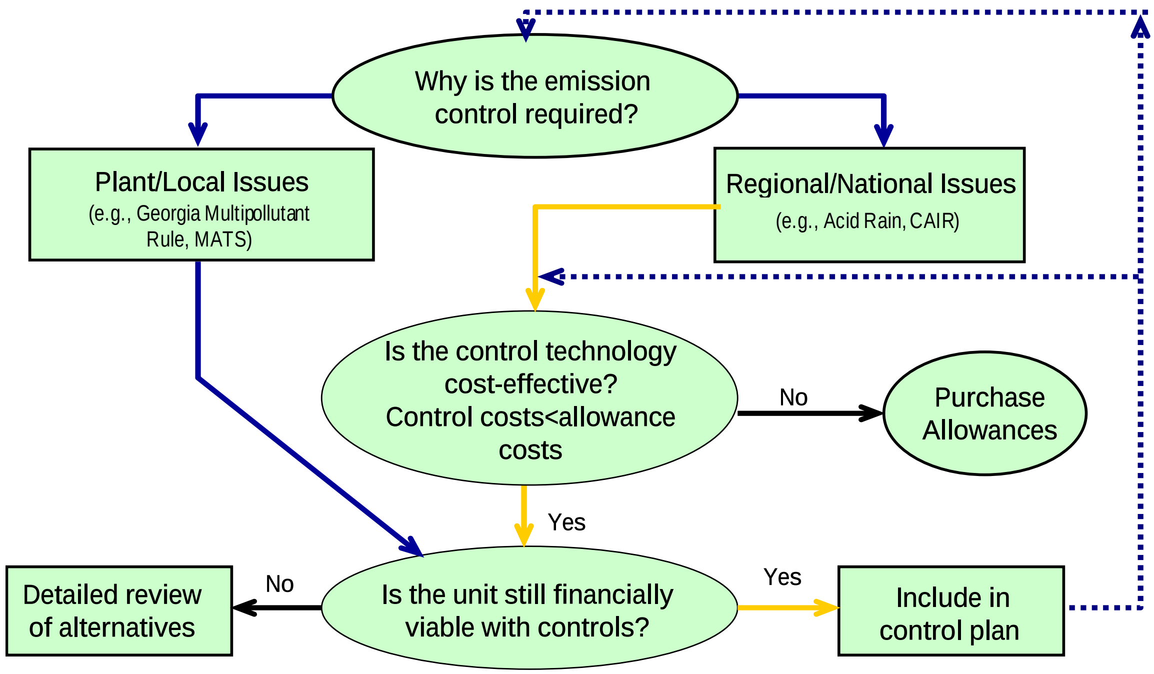


Figure 3.1-2 Visual Representation of the Decision to Control Process

4. **Determining and evaluating the financial impacts of the strategy.** The final step is to make sure that the right economic decision is being made on a plant, GPC, and Southern Company basis for Georgia Power Company and its customers. Some units and plants may not be able to achieve the required emission reductions in a cost-effective manner and would need to acquire additional allowances, switch fuels, or retire to comply. If emission controls are mandated for a specific unit, then the economic value of the generating asset including future operating costs must be considered before application of the technology.

After the process is completed and analyzed across the various planning scenarios, a strategy is compiled on a unit level and reviewed annually based on the most current information. One major goal of the environmental strategy process is to maintain flexibility across the generating fleet. If allowed by the regulations, controls are applied to the most cost-effective units, generally the larger units, first.

A key advantage of this process is that it allows decision making on an incremental basis. While the strategy includes emission control plans for the next 10 years, final decisions on specific pollution control projects are not made until commitments are required so that construction can commence. That is, while controls may be "planned" on a particular unit in 2016, no firm commitment to that plan will be made until necessary to assure that the emission control equipment is in place and operational when needed. This flexibility allows the company to adapt to changing requirements (such as the delay or change in scope of a final rule) and thus reduce costs to the customer.

Future regulatory and legislative requirements that could significantly impact both the scope and the cost of compliance over the next decade are being incorporated into the strategy. Southern Company will continue its involvement in emerging regulations, and these requirements will be incorporated into future strategy updates, as appropriate.

The uncertainty surrounding the legislative and regulatory environment reinforces the need for a flexible, robust compliance plan. Accordingly, the plan balances the need to make decisions on certain timelines (such as fuel and equipment purchases) with the need for more information relative to regulatory and economic drivers. The analysis will be updated to determine the most cost-effective compliance decisions while maintaining future flexibility in the strategy. Additional expenses associated with these regulations are anticipated to be incurred each year to maintain current and future compliance. Because the Company's compliance strategy is impacted by factors such as new regulations, new legislation, changes to existing environmental laws and regulations, the cost of emissions allowances, technology advances, and changes in fuel use, future environmental compliance costs will continue to be incurred.

3.2 Strategy Assumptions

Based on this extensive strategy process and the regulatory and legislative requirements discussed in Section 2.0, the Georgia Power environmental strategy is reviewed and updated each year.

The current and expected requirements underlying the current system strategy include:

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As new and future clean air requirements are implemented, more stringent clean water and solid waste requirements are expected to replace and/or supplement the current rules surrounding water intake, thermal discharge, wastewater, and coal combustion byproduct management. While there is uncertainty surrounding the stringency and timing of these requirements, they must also be considered in the development of the environmental strategy.

The strategy combines the assumptions surrounding the regulatory requirements with the least-cost environmental control technology that is commercially available and results in specific emission control applications across Georgia Power.

3.3 Emission Control Technologies

Research and development are an integral part of the overall Southern Company environmental strategy and compliance plan. Through research, technologies are considered, evaluated, developed, and selected for possible implementation to meet compliance with federal and state regulatory requirements. Technology-related decisions are made based on compliance alternatives, technical review (often following actual testing), schedules, equipment-vendor price quotes, total costs over the useful life, specific unit issues, and performance guarantees. Operational, maintenance, and economic feasibility are an important part of the decision-making process.

Since the Clean Air Act Amendments of 1990 were implemented, research and development have been crucial for Southern Company in assuring that the best possible strategies are selected for implementation. ECS-Appendix B provides a list of technologies considered in an ongoing effort to lower emissions, meet mandated requirements in a timely manner, maintain system reliability, and assure low-cost energy for customers.

Research programs are conducted at GPC plants, at other Southern Company plants across the Southeast, and through industry affiliations at plants across the U.S. and around the world. To minimize cost and risk, only proven technologies should be implemented commercially. Past programs to test low-NO_X burners, precipitators, catalyst materials for Selective Catalytic Reduction (SCR) systems, flue gas desulfurization systems, mercury reduction systems, carbon capture and sequestration (CCS), and other equipment have contributed to Southern Company's ability to meet stringent requirements while enabling GPC to remain a low-cost energy provider for Georgia.

4.0 Strategy Results and Financial Summary

This section summarizes Georgia Power's compliance strategy for environmental requirements. Since the Clean Air Act Amendments were passed in 1990, Southern Company and its operating companies have been challenged by a host of new environmental regulations and requirements as described in Section 2.0. The company has consistently responded with a timely, cost-effective strategy that has either met or exceeded the new clean air requirements, as well as other existing and new environmental regulations.

To date, the applicable regulations and the Georgia Power compliance plan have focused largely on reduction of SO_2 and NO_x emissions, with a more recent focus on mercury and other hazardous air pollutant emissions. Since 1990, Georgia Power has reduced NO_X emissions by approximately 88 percent and SO_2 emissions by approximately 91 percent (including Georgia Power's share of SEGCO). These reductions were achieved by fuel switching to lower sulfur coals and the installation of low-NO_X burners, selective catalytic reduction (SCR) systems, and flue gas desulfurization (FGD or scrubbers) at plants across the system. In addition, state regulations have required the reduction of mercury emissions in Georgia. The combination of baghouses, SCRs, and scrubbers installed at select units has reduced Georgia Power's 2013 mercury emissions by approximately 78% from 2005 levels (including Georgia Power's share of SEGCO).

Numerous additional federal and state regulations are requiring further reductions in power plant air emissions. At the same time, EPA is developing significant new regulations governing water resources and waste management at power plants. The new rules will require reductions in pollutants not regulated to date and will present new challenges. This section reviews the company's compliance strategy for air, solid waste management, and water requirements.

4.1 Air Compliance Strategy Review

The emission reductions that Georgia Power has achieved to date have been driven by the need to comply with many CAA regulations focused on SO_2 and NO_X emissions from power plants, including the Acid Rain Program, Clean Air Interstate Rule, Clean Air Visibility Rule, and state regulations designed to achieve attainment with the ozone and PM NAAQS. More recently, state regulations have also brought focus to mercury reductions from coal-fired power plants and the new MATS rule sets requirements for a range of hazardous air pollutants, including mercury.

Table 4.1-1(below) summarizes the emissions control equipment installed at Georgia Power's coal-fired units since the 1990 Clean Air Act Amendments. ECS-Appendix A provides a reference list of the acronyms/abbreviations used in the table for both controls and vendor names. See ECS-Appendix B for additional technical summaries on emission control technologies.

Table 4.1-1 Current Equipment Installation Status

Unit	Unit Type	NO_X Control	SO_2 Control	Other
Bowen 1	T	LNCFS II (ICL) / SCR	FGD	
Bowen 2	T	LNCFS II (ICL) / SCR	FGD	
Bowen 3	T	LNCFS II (ICL) / SCR	FGD	
Bowen 4	T	LNCFS II (ICL) / SCR	FGD	
Branch 1	C	LNB (B&W)	-	
Branch 3	C	LNB (B&W)	-	
Branch 4	C	LNB (B&W)	-	
Hammond 1	W	LNB	FGD	
Hammond 2	W	LNB	FGD	
Hammond 3	W	LNB	FGD	
Hammond 4	W	LNB / OFA (FW) / SCR (MHI)	FGD	
Kraft 1	T	-	-	
Kraft 2	T	-	-	
Kraft 3	T	-	-	
McIntosh 1	W	OFA	-	
Mitchell 3	T	-	-	
Gaston 1	W	LNB (B&W)	-	
Gaston 2	W	LNB (B&W)	-	
Gaston 3	W	LNB (B&W)	-	
Gaston 4	W	LNB (B&W)	-	
Scherer 1	T	OFA / SCR	FGD	Baghouse / ACI
Scherer 2	T	OFA / SCR	FGD	Baghouse / ACI
Scherer 3	T	OFA / SCR	FGD	Baghouse / ACI
Wansley 1	T	LNCFS II (ABB-CE) / SCR	FGD	
Wansley 2	T	LNCFS II / SCR	FGD	
Yates 1	T	LNB / Gas Injection Capability	FGD	
Yates 2	T	NR / Gas Injection Capability	-	
Yates 3	T	NR / Gas Injection Capability	-	
Yates 4	T	FAN / CCOFA (ICL) / Gas Injection Capability	-	
Yates 5	T	FAN / CCOFA (ICL) / Gas Injection Capability	-	
Yates 6	T	LNCFS II (ICL) / Gas Injection Capability	-	
Yates 7	T	FAN / SOFA (ICL) / Gas Injection Capability	-	

Legend: T – tangentially fired, W – wall fired, C – cell burner.

The discussion below details Georgia Power’s compliance strategy as it relates to each regulatory requirement.

4.1.1 SO_2 Compliance

Since 2007, the SO_2 controls strategy and schedule for Georgia Power have been largely mapped out by the requirements in the Georgia Multipollutant Rule and the companion SO_2 Emissions Rule. The Georgia Multipollutant Rule requires the installation and operation of scrubber systems at certain units by specified dates between 2008 and 2015 and requires switching from coal to natural gas for units at Plant Yates by April 16, 2015. In addition to the reductions that have been driven by the Multipollutant Rule, the sections below review the historical, ongoing, and expected potential impacts of other rules on the SO_2 compliance strategy.

Acid Rain SO_2 Compliance Review
With respect to the Acid Rain Program, Georgia Power's SO_2 compliance strategy involved the creation of a bank of allowances during Phase I (1995-1999) to be carried over into Phase II, which began in 2000. The strategy has historically relied heavily upon use of low-sulfur coals at affected units but is increasingly incorporating FGD (scrubber) systems for SO_2 control at the larger affected units. Both the overall strategy and consistent environmental compliance have been achieved in a cost effective manner. **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

CAIR SO_2 Compliance Review
In 2010, Phase I of the CAIR SO_2 program began. This CAIR SO_2 program augments the Acid Rain Program by requiring affected sources in CAIR states to retire two Acid Rain Program SO_2 allowances for every one ton of SO_2 emitted during the period covered by CAIR Phase I, as opposed to a one-for-one retirement required under the Acid Rain Program. Phase II of the CAIR SO_2 program begins in 2015, at which point 2.86 Acid Rain Program SO_2 allowances must be retired for every one ton of SO2 emitted under CAIR. The SO_2 strategy for compliance with CAIR continues to incorporate the use of low-sulfur coal, installation of scrubbers, and the use of banked and purchased allowances. However, increasingly tight fuel markets have introduced more moderate sulfur coals, while at the same time SO_2 allowance prices are currently at historic lows. These factors combined with the Georgia Multipollutant Rule requirement to install scrubbers on certain units by specified dates have increased GPC's reliance on scrubber installations and reduced reliance on low sulfur coal.

From the time CAIR was finalized in 2005 through the litigation process, the SO_2 allowance market was marked by volatility. As shown in the next figure (Fig. 4.1.1-1), the price for SO_2 allowances has decreased substantially from historically high prices in 2005 and 2006. The market also responded to the July 2008 vacatur of CAIR with a decrease in price and trading. Prices continued to fall in 2012 due to recession-driven electricity demand reductions and continued uncertainty over a CAIR replacement.

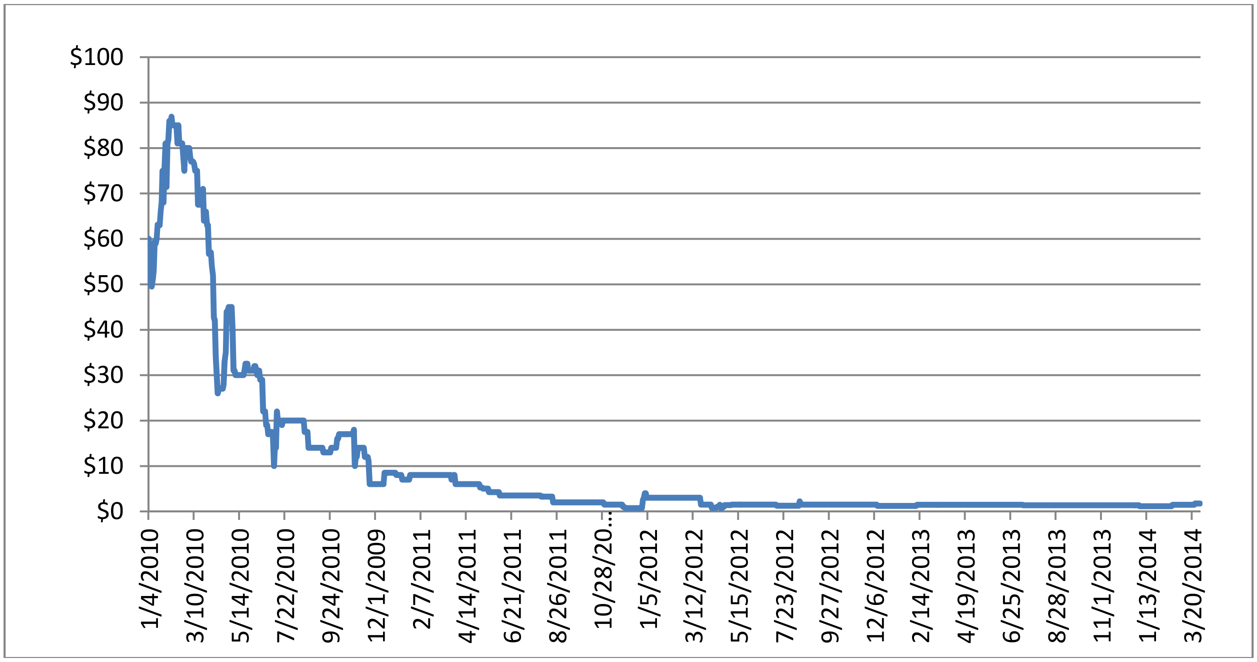

Figure 4.1.1-1 Historical SO_2 Price Summary

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Emission allowance quantities are affected by many factors including regulations, fuel, plant operation and efficiency, outages, control technology, etc., which affect the rate at which the allowances are used. **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

MATS SO_2 or Acid Gases Compliance Review

The MATS rule requires units that have scrubbers installed to comply with either a limit on HCl emissions or a limit on SO_2 emissions. Since scrubbers are effective at removing both HCl and SO_2, the Company's coal-fired units that have or will have scrubbers installed can, in general, meet the MATS limit. However, due to the stringency of the MATS standard and restrictions on the ability to bypass controls, the Company will perform plant-specific optimization projects on the existing scrubbers at Plants Bowen, Hammond, and Wansley to minimize potential impacts to reliability in the future. Coal-fired units without scrubbers will either need to install scrubbers or likely need to use a low chlorine/low SO_2 fuel (e.g. PRB coal) and employ dry sorbent injection (DSI) with hydrated lime to meet the MATS limit. Additional detail regarding the MATS strategy for SO_2/acid gases and the other MATS limits is provided in Section 4.1.3.

Future Rules SO_2 Compliance Review

Expected regulations related to the NAAQS for SO_2 and PM2.5, the Clean Air Visibility Rule, and/or a future replacement for CAIR/CSAPR may drive the need for additional SO_2 reductions strategies in the future.

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4.1.2 NO_X Compliance

Since 2007, the NOx controls strategy and schedule for Georgia Power have also been largely mapped out by the requirements in the Georgia Multipollutant Rule. The Multipollutant Rule requires the installation and operation of SCR systems at certain units by specified dates between 2008 and 2015 and requires switching from coal to natural gas for units at Plant Yates by April 16, 2015. The sections below review the historical, ongoing, and expected potential impacts of other rules on the NOx compliance strategy.

Acid Rain NOx Compliance Review

The Georgia Power NO_X compliance strategy for Acid Rain compliance historically consisted of installing low-NO_X burners, over-fired air (OFA) systems, burner tips, and associated controls. Georgia Power complies with the NOx requirements under the Acid Rain Program through a Southern Company system-wide NOx Averaging Plan. Under the plan, affected units from all of Southern Company's operating companies covered by the regulation must help the system achieve an annual-average NOx emission rate below the specified limit.

The NO_X averaging plan for Southern Company is filed with each State agency and the EPA. System averaging of NO_X emissions lowers system cost and further ensures compliance with Acid Rain regulations. Subsequent regulations, including ozone nonattainment area requirements, CAIR, and the Georgia Multipollutant Rule, have required further NOx reductions which provide significant additional margin for Acid Rain Program NO_X compliance. Controls installed under these regulations, as discussed below, reduce the system average NO_X emissions well below Acid Rain Program requirements.

Ozone Nonattainment Compliance Review

To meet the NO_X reduction requirements for the 1-hour and 1997 8-hour ozone standards, additional controls beyond those necessary for the Acid Rain Program were required.

Various alternatives were considered and evaluated on a technological, operational, and economical basis, including SCR, overfire air, low NOx burners, use of natural gas, PRB coal, and various other low NOx technologies. Analysis of the best solution for NO_X reduction at affected units considered the capital and operating cost of the controls, as well as their performance and resulting production cost savings. Actual compliance implementation decisions were made based on a technical review of the compliance alternatives, equipment-vendor price quotes, specific unit issues, and performance guarantees. In the case of meeting the 1-hour and 1997 8-hour ozone SIPs for the Atlanta area, Plants McDonough Units 1 and 2 (previous to their retirement), Yates Units 1 through 7, Bowen Units 1 through 4, Wansley Units 1 and 2, and Hammond Units 1 through 4 meet specific source NO_X targets or an average 0.13-lb/mmBTU rate during the ozone season. Plants Scherer Units 1 through 3 and Branch Units 1 through 4 are also affected (including Branch Unit 2 previous to its retirement) and meet either specific source NO_X targets or comply as part of the seven-plant average 0.18-lb/mmBTU rate during the ozone season. In addition, Plant Scherer is required to comply with specific source NOx targets or a site-average emission rate of 0.17-lb/mmBTU rate during the ozone season. The seven plant rate and the Scherer site-average rate were revised by the Georgia EPD effective May 1, 2007 to help address 8-hour ozone attainment in Macon, Georgia.

In addition to controls required to comply with ozone nonattainment area requirements, the Georgia Multipollutant Rule requires the installation and operation of SCR systems at certain additional units by specified dates between 2008 and 2015.

In anticipation of possible requirements due to the Atlanta area's nonattainment status under the 2008 8-hour ozone standard or due to EPA's planned revision to the ozone standard in 2014, additional NOx reductions may be required in the future. **REDACTED REDACTED REDACTED REDREDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

CAIR Annual NO_X Compliance Review

The Georgia Power CAIR Annual NO_X compliance strategy has involved purchasing allowances for CAIR Phase I (2009-2014) to supplement reductions from NO_X controls. The Annual NO_X strategy can include fuel switching, low NO_X burners, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), the use of banked and purchased Annual NO_X allowances, and unit retirement.

Like the SO_2 market, the Annual NO_X allowance market was marked by volatility prior to and following the CAIR litigation. The market for NO_X allowances dropped in price and trading volume in July 2008 and rose in December 2008 following the remand. Prices started to fall in 2009 and continued to fall in 2012 due to recession-driven electricity demand reductions and continued uncertainty over a CAIR replacement. Figure 4.1.2-1 shows historic Annual NO_X prices since 2008.

While annual NO_X allowance purchases played a significant role in achieving CAIR Annual NOx compliance in the early years of the program, Georgia Power now complies primarily through the use of SCR NO_X controls at Georgia Power units. **REDACTED REDACTED**

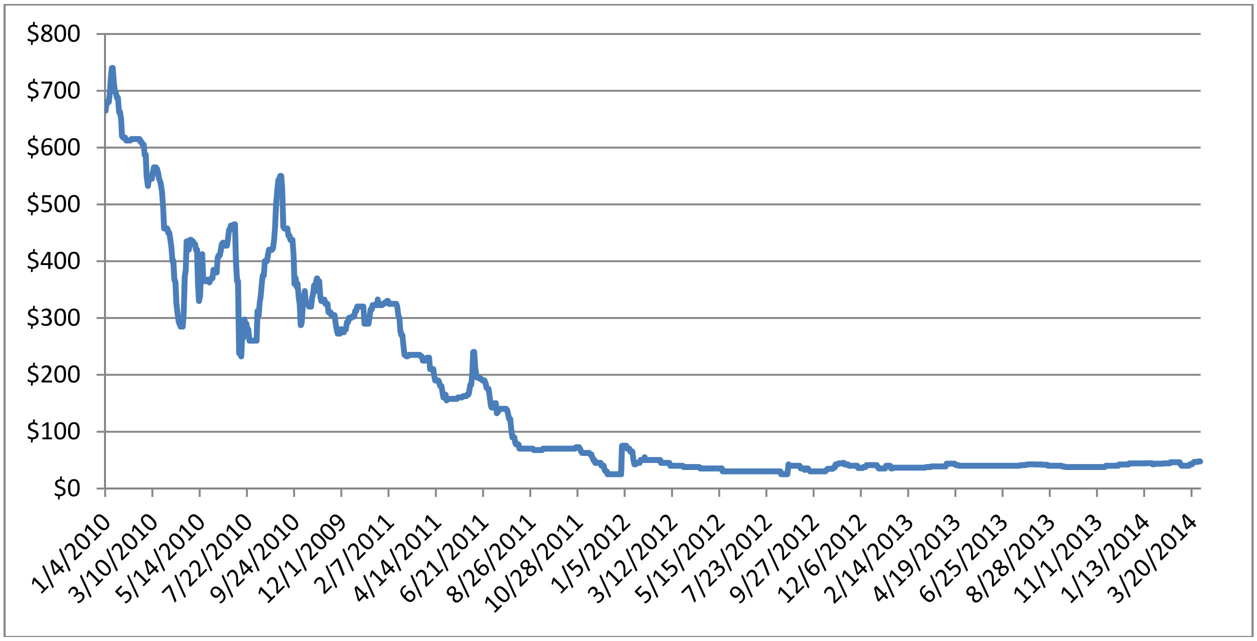

Figure 4.1.2-1 Historical Annual NO_X Price Summary

CAIR Seasonal NO_X Compliance

The Georgia Power CAIR Seasonal NO_X compliance strategy is functionally identical to the Annual NO_X compliance strategy. Compliance is assured through a mix of Seasonal NO_X allowance purchases and NO_X emission controls. Emissions control decisions are driven by Annual NO_X compliance.

Georgia Power's only units subject to a Seasonal NO_X program have been the SEGCO units in the State of Alabama (Plant Gaston Units 1 – 4), which were subject to the NOx Budget Trading Program and are currently subject to the CAIR Seasonal NOx program. If CSAPR is reinstated, all of Georgia Power's fossil fuel fired units would become subject to the CSAPR Seasonal NOx program.

The needs and the costs for purchasing Seasonal NO_x allowances vary on a year-by-year basis. The current Seasonal NO_X market is depressed along with the Annual NO_X market for the same reasons. Figure 4.1.2-2 shows historical Seasonal NO_X prices. **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

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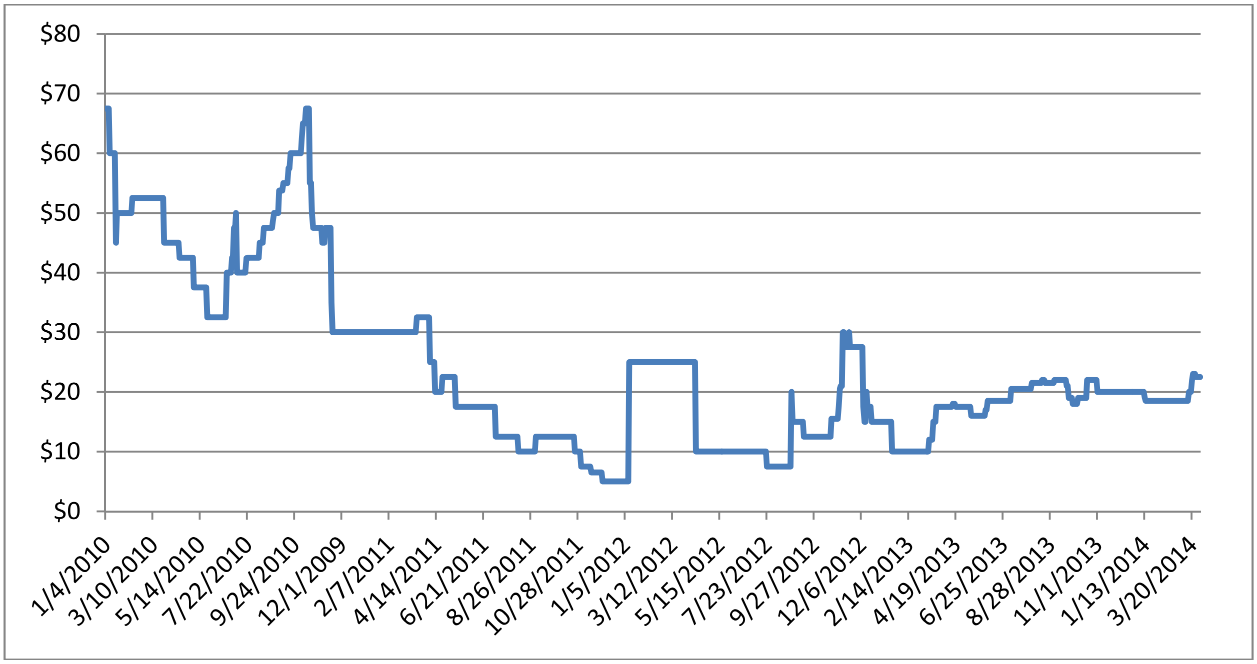

Figure 4.1.2-2 Historical Seasonal NO_X Price Summary

Future Rules NOx Compliance Review

Expected regulations related to the NAAQS for ozone, the Clean Air Visibility Rule, and/or a future replacement for CAIR/CSAPR may drive the need for additional NOx reductions strategies in the future.

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4.1.3 Mercury and Air Toxics Standards

In addition to the SO_2 drivers for environmental compliance strategy planning discussed in the MATS section of 4.1.1, MATS also includes requirements that will lead to further controls for mercury and particulate matter. Georgia Power has conducted an extensive review of the new MATS Rule and has developed plans or compliance options for all affected units, as discussed further below. Compliance with the MATS Rule is required by April 16, 2015. Georgia Power has secured one-year extensions of the compliance deadline for certain units as discussed in more detail below.

MATS Compliance Strategy

Georgia Power and Southern Company are uniquely positioned to understand and implement mercury control technology appropriately across the operating fleet in large part due to the wealth of research and demonstration experience. Southern Company has collaborated with the U.S. Department of Energy (DOE), the Electric Power Research Institute (EPRI), equipment suppliers, and other utilities on mercury research. Building off of its previous experience, the Company's research and testing program has enabled it to make individualized, targeted decisions for each unit that optimizes the available technology while minimizing costs to the customer.

Scrubbed Units

Units that have scrubbers existing or under construction are generally able to meet the SO_2/acid gases limit under MATS, but compliance with the mercury and particulate limit and the need for baghouses and other controls had to be further evaluated. Units that fall into this category include the coal-fired units at Plants Bowen, Hammond, Wansley, Scherer, and Yates Unit 1. In addition to existing scrubbers, the units at Plant Scherer also already operate existing baghouses with activated carbon injection for mercury control.

For mercury, significant reductions are achieved on bituminous coal-fired units through the mercury reduction and capture co-benefits of the SCR and scrubber. However, additional incremental reductions must be achieved on all units at Bowen, Hammond, and Wansley to comply with the MATS mercury limit on a continuous basis. These reductions can be achieved with the installation of activated carbon injection (ACI) and alkali sorbent injection (ALK) systems upstream of either an existing electrostatic precipitator or a baghouse. The activated carbon is injected into the flue gas to capture the mercury resulting from combustion of coal in the boiler. ALK is defined as hydrated lime that is injected into the flue gas upstream of the activated carbon to enhance the effectiveness of the activated carbon. The hydrated lime and activated carbon will then be collected in the electrostatic precipitators or baghouses.

Whether a unit requires a baghouse or can use its existing electrostatic precipitator with the activated carbon and hydrated lime depends on unit-specific characteristics. Baghouse retrofits are necessary for units, such as Bowen Units 3 and 4, that tend to have higher mercury emissions and that require additional particulate matter control to ensure compliance. For units that will not install baghouses, upgrades to the existing electrostatic precipitator are recommended to maintain emissions performance with the additional loading of the injected carbon and hydrated lime. In addition, scrubber additives are recommended to help control mercury re-emission, which can occur under certain conditions in the scrubber and can counteract the reductions provided upstream of or by the scrubber. The use of scrubber additives in a mercury re-emission control system can also help prevent over-injection of activated carbon and lime into the baghouse or precipitator, thus minimizing the ongoing operational cost of the controls.

GPC is installing baghouses at Plant Bowen Units 3 & 4, but is not installing baghouses at Plant Bowen Units 1 & 2, Plant Wansley Units 1 & 2, and Plant Hammond Units 1-4. All coal-fired units at these sites will install activated carbon injection (ACI) and alkali sorbent injection (ALK) systems upstream of either the baghouse or the electrostatic precipitator. All units plan to install mercury re-emission control systems and non-baghouse units will perform electrostatic precipitator upgrades.

For its PRB coal-fired units at Plant Scherer, the Company expects to achieve the necessary mercury reduction most cost effectively by employing a combination of already planned SCR, scrubber, carbon injection, and baghouse systems as well as application of calcium bromide to the fuel. The application of calcium bromide to the fuel is intended to reduce the amount of carbon injection that is necessary to achieve continuous mercury compliance by enhancing the mercury removal by the scrubbers. Because the cost of carbon is relatively higher, use of calcium bromide will reduce overall O&M expenses related to operating the environmental controls and help ensure compliance.

Given the stringency of the final MATS requirements and the reduced operational flexibility expected as a result, additional MATS compliance measures will be implemented at Bowen, Hammond, and Wansley to optimize the balance of plant performance and ensure reliability of mercury, acid gas, and particulate controls.

Yates Unit 1 is a unique case in the Georgia Power fleet because it operates an existing, older standalone scrubber at a relatively small coal-fired unit. However, even with an existing scrubber, costs to either comply with MATS on coal or switch to natural gas are very significant. Because neither compliance with MATS nor switching from coal to natural gas is cost effective, Plant Yates Unit 1 will be retired by April 16, 2015.

Non-scrubbed Units

For units that do not already have scrubbers, the chosen compliance strategy is based on site-specific factors and evaluations. The strategies for these units are discussed below:

Units at two plants, Plant Yates Units 6 and 7 and Plant Gaston Units 1-4 (SEGCO), will switch to natural gas as the primary fuel. By switching to natural gas, these units will no longer be subject to MATS, because MATS applies only to coal- and oil-fired units. The Company has determined that use of natural gas at these plants is the most economic choice for customers and is feasible both from a boiler technology as well as a natural gas fuel supply perspective.

The Company plans to switch Plant McIntosh Unit 1 from bituminous coal to sub-bituminous coal (PRB). By switching to PRB fuel, Plant McIntosh Unit 1 is able to comply with MATS using alternatives to scrubber and baghouse technology. Because PRB is a low-chlorine and low-sulfur coal, compliance is expected to be achieved through the use of dry sorbent injection (DSI) into the existing precipitator. In addition to DSI for acid gas control, McIntosh Unit 1 would also use ACI into the existing precipitator for mercury control. More detailed evaluations of optimization of the existing McIntosh Unit 1 precipitator are ongoing.

The Plant Mitchell Unit 3 conversion to biomass was certified in 2009, but in January 2014 the Company filed plans with the PSC to cancel the biomass project.

For Plant Mitchell Unit 3 and other unscrubbed coal- or oil-fired steam generating units, including Branch Units 3 and 4, Yates Units 2 through 5, Kraft Units 1 through 4, and McManus Units 1 and 2, options for MATS compliance are very limited and/or costly. Thus, these units will be retired.

MATS Schedule

As a critical part of the MATS compliance strategy, Georgia Power will need to utilize all tools necessary to strive to meet the compliance deadline including seeking available extensions. This additional time for compliance may be necessary for the installation of controls and the multitude of other compliance and operational planning, such as: startup/shutdown, monitoring and testing, balance of plant impacts, operational management, boiler tuning, and personnel training, among other compliance considerations. The schedule for implementing controls will also reflect the necessity of coordinating multiple outages across the Southern Company's integrated generating systems and within the region. At this time, the Company has determined that extensions are required for the Plant Gaston Units 1 through 4 natural gas projects, the Plant Bowen baghouse projects at Units 3 and 4, and for Plant Kraft as a result of the transmission upgrades that are needed in the area to maintain reliability after the plant is decertified. The Alabama Department of Environmental Management granted a one-year extension for Plant Gaston Units 1 through 4 on March 7, 2013. The Georgia Environmental Protection Division granted one-year extensions for Bowen Units 3 and 4 and Plant Kraft on September 10, 2013. **REDACTED REDACTED REDACTED REDACTED**

4.2 Water Compliance Strategy Review

The Water Compliance Strategy considers a variety of existing and pending regulations related to both water quality and biological impacts. The strategy considers both nationwide standards as well as state requirements developed for specific water bodies. The potential impacts to Georgia Power are discussed below.

Water Intake Structures/Cooling Towers

Georgia Power is currently evaluating compliance alternatives for the Section 316(b) rule. **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED** The current strategy is based on unit-specific evaluations for the proposed rule. The strategy may change depending on the ongoing evaluations of the final rule.

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Wastewater Treatment Facilities

There are several drivers that may compel wastewater treatment on multiple waste streams at Georgia Power plants. Preliminary information released by EPA indicates that the upcoming Steam Effluent Limitation Guidelines (ELGs) may include stringent wastewater treatment limits for scrubber systems that have been installed across the Georgia Power system to meet air regulations. In addition to scrubber wastewater limits, the ELGs also may impact handling of fly ash, bottom ash, and flue gas mercury control waste, as well as landfill leachate and nonchemical metal cleaning waste treatment requirements. State water quality standards and TMDLs for impaired water bodies also have the potential to require stringent wastewater treatment.

Southern Company has been actively engaged with EPA and the electric power industry to compile information for the ELG rulemaking process. By providing critical data and evaluating the feasibility and costs of available treatment technologies, Southern Company seeks to ensure compliance in the most cost-effective and efficient manner, while providing for continued protection of water quality and aquatic resources.

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In order to meet the growing challenges of water treatment and supply issues, Georgia Power has funded and created the Water Research Center (WRC), a first-of-its-kind facility for water conservation and technology development. The center began operation in the Fall of 2012 and is a collaboration with EPRI and the Southern Research Institute (SRI). Located at Plant Bowen in northwest Georgia, the WRC will allow companies worldwide to test technologies to improve water use efficiency and water treatment that may be required for compliance with upcoming regulations.

4.3 Solid Waste Management

As a result of the compliance strategy for MATS and other rules, the Company has developed plans to address solid waste management needs that result from the installation of additional emission controls, such as scrubbers, baghouses, and sorbent injection systems. The solid waste management strategy resulting from these existing requirements includes continued use of existing ash ponds, construction of on-site and off-site ash and/or gypsum landfills, and lining of landfill cells as required by the Georgia Environmental Protection Division.

In addition to the ongoing strategy for solid waste management under existing regulations, Southern Company and GPC are currently evaluating compliance alternatives and requirements under the proposed Coal Combustion Residuals (CCR) rule. The financial and operational impacts of this rule will depend on numerous factors, including: whether coal combustion byproducts will be regulated as hazardous waste or non-hazardous waste; whether EPA will require early closure of existing wet storage facilities; whether beneficial reuse will be limited or eliminated through a hazardous waste designation; whether the construction of lined landfills is required; whether hazardous waste landfill permitting will be required for on-site storage; whether additional wastewater treatment will be required; the extent of any additional groundwater monitoring requirements; whether any equipment modifications will be required; the extent of any changes to site safety practices under a hazardous waste designation; and the time period over which compliance will be required.

The current strategy is based on the proposed CCR rule, which indicated that facilities would have to install groundwater monitoring around all ash ponds and could no longer use ash ponds for coal ash storage or disposal. **REDACTED REDACTED** Because the CCR and ELG rules are not final, exact compliance requirements are uncertain at this time and cannot be determined until the final rules are issued.

GPC will continue to comply with all applicable state and federal regulatory requirements and is continually seeking to increase appropriate beneficial use of coal combustion byproducts that it generates. In addition, Georgia Power continues to manage the impacts on solid waste management from EPA rules related to air and water quality. The CCR rule and its potential impacts on the ability to beneficially re-use coal combustion byproducts and the byproducts generated by scrubbers and baghouses all have the potential to impact the future need for new on-site or off-site landfills.

4.4 Strategy and Schedule

The environmental strategy and schedule continues to evolve, even as state and federal requirements are being proposed and finalized. The current 2014 GPC environmental strategy and schedule for both Air (Fig. 4.4-1) and Land and Water (Fig. 4.4-2) are provided in the following figures. In general, certain aspects of the strategy are constantly under reevaluation and the schedule remains dynamic.

REDACTED

Figure 4.4-1 Environmental Compliance Schedule (Air Only)
2014 Financial Plan for GPC

REDACTED

Figure 4.4-2 Environmental Compliance Schedule (Land and Water)
2014 Financial Plan for GPC

In summary, in developing the air compliance schedule, **REDACTED REDACTED**

For the land and water compliance schedule, **REDACTED REDACTED**

REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED In addition to those projects included above in the current air and land and water schedules, additional compliance obligations are possible as a result of new or revised future rules.

4.5 Financial Summary

Through 2013, Georgia Power has invested approximately $4.3 billion in capital projects to comply with applicable environmental statutes. GPC's annual totals have been $309 million, $152 million, and $113 million in 2013, 2012, and 2011, respectively. In Georgia Power's Annual Report on Form 10-K for the year ended December 31, 2013, Georgia Power projected that base level capital expenditures to comply with existing statutes and regulations will be a total of approximately $1.1 billion from 2014 through 2016, with annual totals of approximately $543 million, $366 million, and $202 million for 2014, 2015, and 2016, respectively. As approved by the PSC, incremental costs related to environmental compliance—including both incremental environmental capital that will be placed in service in 2015 and incremental O&M costs—will be included in the Company's October compliance filing in connection with the Environmental Compliance Cost Recovery tariff in accordance with the PSC's final order in Docket No. 36989.

The Company's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of any new or revised environmental statutes and regulations that are enacted, including the proposed environmental legislation and regulations described below; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix.

In addition to capital and O&M financial impacts from the installation of environmental controls, Title IV of the 1990 Clean Air Act and CAIR both can financially impact the Company through SO_2 and NOx emission allowances. The company's allowance purchase strategy is discussed below.

4.5.1 Allowance Strategy

Southern Company and GPC manage allowance resources by balancing compliance with value. It is imperative to ensure sufficient allowances are available and allocated to the correct generating unit accounts to satisfy the requirements of the CAAA and CAIR. The planning process outputs projected allowance needs over time for GPC. However, the volume of allowances surrendered for compliance will depend upon the individual unit operations realized within that compliance year. Southern Company, functioning as a centrally dispatched system, has a mechanism in place to track unit operations. At the end of a compliance period, any reallocation of allowances between or among units only takes place at the operating company level.

Value management focuses on optimizing the use of the allowances available to Georgia Power. The goal of value management is to plan for the ultimate disposition of allowances in a manner that will serve in the best interest of GPC's customers.

ECS-APPENDIX A

ACRONYMS/ABBREVIATIONS AND TERMINOLOGY

ABB	Asea Brown Boveri (LNB vendor)
ABBCE	Asea Brown Boveri Combustion Engineering
ACI	Activated Carbon Injection
ALK	Alkali Sorbent Injection
B&W	Babcock & Wilcox (LNB vendor)
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CAA	Clean Air Act
CAAA	Clean Air Act Amendments (of 1990)
$CaBr_2$	Calcium Bromide
CAIR	Clean Air Interstate Rule
CAVR	Clean Air Visibility Rule
CCOFA	Close-Coupled Overfire Air
CEMS	Continuous Emissions Monitoring System
CFS	Concentric Firing System
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COHPAC	Compact Hybrid Particulate Collector
CWA	Clean Water Act

CWWS	Cylindrical Wedge Wire Screens
DOE	Department of Energy
EEI	Edison Electric Institute
EPA	Environmental Protection Agency
EGU	Electric Generating Unit
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FAN	Flame Attachment Nozzle - A low-NO_X burner tip design by ICL
FCCC	Framework Convention on Climate Change
FGD	Flue Gas Desulfurization
FW	Foster Wheeler (LNB vendor)
GEPD	Georgia Environmental Protection Division
GPC	Georgia Power Company
HAP	Hazardous Air Pollutant
HDPE	High-Density Polyethylene
Hg	Mercury
LNB	Low-NO_X Burner
LNCFS	Low-NO_X Concentric Firing System
LNCFS I	LNCFS + CCOFA
LNCFS II	LNCFS + SOFA

LNCFS III	LNCFS + CCOFA + SOFA
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
MRCS	Mercury Re-emission Control System
NAAQS	National Ambient Air Quality Standards
NH_3	Ammonia
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxide
NPDES	National Pollution Discharge Elimination System
NR	Not required for compliance under current averaging plans
NSR	New Source Review
OFA	Overfire Air
PJFF	Pulse-Jet Fabric Filter
PM	Particulate Matter
PM2.5	Particulate Matter less than 2.5 micrometers in size
PRB	Powder River Basin
RACT	Reasonably Available Control Technology
RCRA	Resource Conservation and Recovery Act
ROFA	Rotating Overfire Air
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan

SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SOFA	Separated Overfire Air
T-Fired	Tangential or tangentially fired
TMDL	Total Maximum Daily Load
TWS	Travelling Water Screens
UARG	Utility Air Regulatory Group
UFGI	Upper Furnace Gas Injection
USWAG	Utility Solid Waste Activities Group
UWAG	Utility Water Act Group
VOC	Volatile Organic Compounds

ECS-APPENDIX B

EMISSION CONTROL ALTERNATIVES

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EMISSION CONTROL ALTERNATIVES

I. Selective Catalytic Reduction (SCR)

SCR technology involves the catalytic reaction of ammonia (NH_3), which is injected into the flue gas, with NO_X to produce molecular nitrogen (N_2) and water vapor. These reactions take place across multiple layers of catalyst in the SCR reactor and generally result in a NO_X reduction capability of 85 to 90 percent depending upon the particular application. Theoretically, the NO_X and ammonia react in the presence of SCR catalysts. However, side reactions that produce undesirable byproducts can occur between ammonia and sulfur trioxide (SO_3) in the flue gas.

The SCR operating temperature ranges from 550 to 750°F. As a result, the SCR system normally is located in a high-dust configuration between the boiler economizer flue gas outlet and the air preheater flue gas inlet where the above temperature range normally occurs. Prior to entering the reactor, ammonia is injected into the flue gas at a sufficient distance upstream of the reactor to provide for adequate mixing of the ammonia and flue gas. The quantity of ammonia injected is adjusted to maintain the desired NO_X reduction level (within design limits). NO_X emissions are reduced in direct proportion to the quantity of ammonia injected up to an ammonia-to-NO_X ratio (NH_3/NO_X) of approximately 0.80. Above this value (and as the activity of the catalyst declines with age), some of the ammonia can escape the SCR reactor as ammonia slip. This ammonia can react with small quantities of SO_3 present in the flue gas to form ammonium bisulfate, which can foul and/or increase the corrosion potential for downstream equipment.

II. Selective Noncatalytic Reduction (SNCR)

SNCR employs chemical injection of ammonia or urea directly into the boiler at a flue gas temperature between 1,600 and 2,100°F. In this temperature range, which is typically near the top of the boiler close to the furnace exit or in the convective pass, the reagent reacts with NO_X to form nitrogen and water without the use of a catalyst to promote the reaction.

As with SCR, the ammonia slip constraint imposes a limit on the maximum amount of NO_X that can be removed with the SNCR process. Because the process is so temperature sensitive, the ability to follow boiler load becomes critical when constrained by ammonia slip limits. Advanced SNCR systems use retractable injection lances that improve load-following control for the process. These lances use a "jet curtain" to provide better cross-sectional coverage and rotation of the lance allows for better response to process signals such as boiler load or furnace temperature.

Application of SNCR to utility-scale boilers is highly site specific. Generally, SNCR is capable of 15- to 40-percent NO_X removal, consistent with a 5-ppm ammonia slip constraint. Removal levels above 40 to 50 percent are difficult to achieve due to the high-ammonia slip that is produced, the stringent requirements placed on the distributions for injected reagents, and the narrow temperature window required for the reaction.

One particular benefit of SNCR as compared to SCR is that capital cost is limited due to the absence of catalyst and the associated reactor vessel. However, potentially much higher ammonia slip levels cause increased downstream problems. In addition, the difficulty in meeting temperature and distribution requirements makes implementation of the technology difficult on many boilers, especially on a large scale boiler (typically greater than 300 MW). SNCR systems also generally require more reducing agent for a given NO_X reduction than do SCR systems since part of the reducing agent can be oxidized at the higher injection temperature, representing an initial loss of reagent. Furthermore, the oxidation product is often NO_X, requiring additional reagent (ammonia) to remove the NO_X formed via oxidation.

III. Fuel Switch to Natural Gas

Existing coal plants can be partially or completely converted to burn natural gas instead of coal. Since natural gas contains very little sulfur, sulfur oxide emissions can be reduced to a level that is below that produced by flue gas desulfurization. Natural gas does not have constituents that remain after combustion to create ash, unlike coal where the natural minerals are transformed in the coal combustion process. Trace metals, which are present in coal, are largely absent from natural gas and so they are not emitted from natural gas combustion.

Nitrogen oxides or NOx results from both fuel chemistry and from the air used in combustion. Therefore, a natural gas conversion does not automatically eliminate emissions of nitrogen oxides. The level of NOx in such a conversion is determined by the boiler design plus the presence and design of low NOx firing systems (see the next section). Well designed and operated low NOx firing systems on coal boilers can produce similar NOx emissions to those seen in natural gas conversions.

Natural gas steam electric boilers are not subject to the MATS rule, which also allows up to an annual 10% heat input from coal. Thus a coal boiler which is switched to natural gas could still use coal as a backup fuel and not be subject to MATS requirements.

The choice of switching a coal boiler to natural gas is complex, with many factors to be considered. The location of natural gas pipelines, the availability of natural gas in either summer or winter, the energy diversity of the generating fleet, the other environmental regulations surrounding coal ash and water treatment, and local ambient air attainment status all have to be considered. Switching a coal unit to natural gas can produce lower emissions and – if natural gas prices remain low – produce affordable electricity for customers.

IV. Low-NO_X Burners (LNBs) and Overfire Air (OFA)

Low-NO_X burner is a generic term for a burner designed to combust the fuel while reducing the amount of NO_X that is formed. Since there are several different firing arrangements for oil- and coal-fired boilers, there are several different types of LNBs.

NO_X is formed during combustion from either the nitrogen in the fuel or the air. NO_X formed from nitrogen in air requires high-flame temperatures and because of this, is usually referred to as thermal NO_X. Some fuels, particularly coal and oil, contain small amounts (2 percent or less) of nitrogen as a chemical constituent. When these fuels are burned, this fuel nitrogen can be oxidized in the flame-producing NO_X, which is referred to as fuel NO_X. Thus coal and oil can form NO_X from the thermal NO_X and the fuel NO_X mechanisms, but the fuel-nitrogen pathway is by far the predominant one. Since natural gas contains no fuel nitrogen, thermal NO_X *only* is formed, explaining why natural gas flames have much lower NO_X levels than coal.

LNBs for coal and heavy oil are designed to reduce NO_X by allowing the fuel nitrogen to be released from the fuel in a region with low-oxygen concentration. Most of the fuel nitrogen can then react to molecular nitrogen (N_2, which is present in the air). High temperatures are needed to extract most of the nitrogen from the fuel and low-oxygen concentrations are also necessary to prevent the fuel nitrogen from being oxidized. This approach is known as air staging because a portion of the combustion air must be introduced later in the combustion process to form this low-oxygen reduction zone. Wall-fired LNBs achieve this end by an aerodynamic trick in each burner's flame while, in a tangentially fired furnace, a portion of the secondary air is diverted above the flame (overfire air), producing a low-oxygen zone in the entire lower furnace.

LNBs for wall-fired units are typically dual-register burners. By using two separate registers for the secondary air, some of the secondary air is used to initiate and stabilize the flame (with inner-register air), while most of the secondary air is directed by the outer register to bypass the initial flame and then mix with the flame after the fuel nitrogen is released and converted to N_2. Different manufacturers use different hardware implementations for this process, but the general technical concept is much the same. Most also use some means of ensuring the flame stays attached to the tip of the burner. A stable, attached flame is a lower NO_X producer than either an unstable flame or a detached flame.

LNBs for tangentially fired boilers serve to assist in NO_X reduction by supporting the air staging used for the major NO_X reduction technique. There are different manufacturing designs for low NOx burners for these plants, that control the mixing and direction of the combustion air relative to the coal-air mixture injected into the furnace. Most tangentially-fired boilers rely heavily on overfire air in addition to low NOx burners.

Overfire air (OFA) is a very effective method to reduce NOx emissions. In fact, the most general approach to lowering NO_X produced in oil or coal combustion is to create a main flame zone that is deficient in oxygen and is known as a reducing atmosphere. If the temperature can be held high in this reducing zone, the majority of the fuel nitrogen can be driven from the fuel. Since little oxygen would be present, this fuel nitrogen then reacts to form molecular nitrogen (N_2), which is the main constituent of air. OFA is the air that is added to finish the combustion process started in the combustion zone. In a vertical flow typical of boilers, the reducing zone is the main combustion zone. OFA is added above this flame zone, thus the name "overfire" air.

Up to approximately 30 percent of the total air needed for combustion may be supplied as OFA. As the amount of OFA increases, the NO_X emissions of the combustion process decrease, up to a point. Any further increase in the amount of OFA above this point will cause the NO_X emissions to increase. The practical limitations on the amount of OFA that can be used are:

- Stability of the main flame.
- Corrosion of the metal steam tubes.
- Production of carbon monoxide.
- Increases in the amount of unburned carbon that escapes the furnace and is collected with the fly ash.

OFA is a part of most of the tangentially fired NO_X control systems described.

V. Powder River Basin (PRB) Coal

PRB coal is a subbituminous coal mined primarily from seams in the PRB located in Wyoming and Montana in the western United States. Reasons for broadening the use of PRB coal include favorable economics and the added benefits of lower fuel-bound nitrogen and sulfur components that enhance the ability of generating units to minimize NO_X, as well as SO_2 emissions. Additional NO_X reductions are realized because of the lower combustion flame temperature brought about by the higher moisture content in PRB coal. With this increase in moisture content come lower heat contents (heating values), suppression of mill outlet temperatures below design minimums, possible loss of generation due to unit-load deratings, and potential increased forced outage rates during the peak season. Increased heat rate and higher operating and maintenance costs are also usually associated with a switch to PRB coal from bituminous coal. Compacting the stockout piles and increased housekeeping around transfer points are considerations to alleviate potential problems with self-heating of the higher-reactivity PRB coal. Soot blower maintenance and increased boiler inspection may be required to maintain/sustain boiler operation. ESP capacity may also be affected and additional fields or flue gas conditioning may be required to adequately collect the PRB fly ash. The impact on SCR catalyst activity of elevated levels of alkali earth metals in PRB fly ash is also a concern, but has been seen as a controllable factor.

VI. Flue Gas Desulfurization (FGD)

Flue gas from coal- and oil-fired boilers will contain sulfur oxides produced from any sulfur in the fuel. FGD is any process that removes these sulfur oxides, primarily sulfur dioxide (SO_2)

with a small amount of sulfur trioxide (SO_3). These sulfur oxides, or SO_X, can range from 0.3 percent of the flue gas by volume down to several hundred parts per million. The two main types of processes are characterized by either wet- or dry-process chemistry.

As implied by the category, wet processes collect the SO_X by treating the flue gas with a water-based solution or slurry. One typical design the utility industry uses is a spray tower module where the flue gas flows up the tower and a series of nozzles spray an alkaline solution into the flue gas. The common chemical used in wet scrubbers is limestone ($CaCO_3$) and the solids produced by modern designs are predominantly calcium sulfate ($CaSO_4$), or gypsum. This gypsum can either be sold as a pre-cursor to wallboard, used for agricultural purposes or be disposed of in a landfill or pond. The wet processes are very efficient and remove 80 to 99 percent of the SO_2 in flue gas with 95 percent removal typical.

Dry processes inject an alkaline slurry into the flue gas stream in a spray dryer followed by a particulate control device. The spray dryer is a unit where the hot flue gases are contacted with the wet alkaline spray that absorbs the SO_2. The hot flue gas evaporates the water and leaves a dry residue that can then be captured with the fly ash, typically in a baghouse. ESPs are normally not used behind a spray dryer because of the high resistivity of the calcium residues that are added to the fly ash. The residue also contains a mixture of calcium sulfite/sulfate, along with the fly ash from the fuel. This waste is not suitable for other uses and must be disposed of in a landfill or pond. Historically, dry scrubbing is considered to typically remove 75 to 90 percent of the SO_2 in flue gas.

VII. Dry Sorbent Injection (DSI)

Dry sorbent injection is a technology that can help reduce acid gas emissions, as required by the MATS rule. DSI systems remove hydrogen chloride (HCl) and other acid gases through two basic steps. In step one, a powdered sorbent is injected into the flue gas—combustion exhaust gas exiting a power plant—where it reacts with the HCl. The sorbents most commonly associated with DSI are trona (sodium sesquicarbonate, a naturally occurring mineral mined in Wyoming), sodium bicarbonate, and hydrated lime.

For step two, the compound is removed by a downstream particulate matter control device such as an electrostatic precipitator (ESP) or a baghouse. Baghouses are generally more effective (when combined with DSI) than ESPs, with respect to overall HCl reduction. For modeling purposes, EPA estimates a DSI system with a baghouse is expected to achieve 90% removal of HCl, while an ESP only achieves 60% removal, although actual performance will vary by individual plant.

DSI systems generally do not require significant capital expenses, but may rely on significant quantities of sorbent to operate effectively, which increases the operating costs. Waste disposal for DSI may also be a significant variable cost, while the waste products from an FGD system can be sold as feedstock for industrial processes. In addition, DSI's potential effectiveness is limited to certain types of plants. Because of the amount of sorbent needed, DSI will likely be implemented most often at plants that are 300 megawatts or less and burn low-sulfur coal.

DSI systems can also significantly reduce sulfur dioxide (SO_2) emissions through the same process as HCl removal. While the MATS rule does not specifically address SO_2, it has similar qualities to HCl and other acid gases that enable it to respond similarly in a DSI system.

VIII. Baghouses

Baghouses are filter devices that remove solid particles from flue gas streams by passing the gases through a fabric, and thus collecting the particles. While baghouses can either operate as a standalone control device or in conjunction with other particulate capture devices, all of Georgia Power's existing and planned baghouses will be located downstream of the plant's existing electrostatic precipitators. This configuration – a baghouse located downstream of an existing ESP – was patented by EPRI and is known as a Compact Hybrid Particulate Collector (COHPAC).

The basic COHPAC concept is to place a pulse-jet fabric filter (PJFF) downstream of an existing ESP to serve as a "polishing" or performance-upgrading unit. The flue gas enters the PJFF and passes through the fabric where the fly ash particles are filtered from the gas. The particles are collected on the outside of the fabric and the resulting dust layer is cleaned from the bags by air pulses (and thus, the nomenclature: pulse-jet fabric filters). Since the ESP removes a significant amount of the particles from the gas stream the flue gas reaching the baghouse has a significantly reduced dust load. The residual electrical charge from particle charging in the ESP and low-dust loading enables the COHPAC PJFF to operate at an air-to-cloth ratio (A/C) in the 6 to 12 range. (A/C is a ratio of the amount of gas to the amount of fabric present.) A typical full-scale PJFF without an upstream ESP must operate at A/C ratios of 4 or below, allowing the physical size of a COHPAC PJFF to be up to one-fourth the size of a normal PJFF, which reduces the cost significantly.

IX. Activated Carbon Injection and Alkali Sorbent Injection

Activated carbon injection (ACI) for Hg control involves the addition of powdered activated carbon to flue gas streams where it adsorbs vapor phase mercury. This powdered material is made by "cooking" low rank coals with steam and temperature to activate the surface, generating a highly reactive product that acts like a chemical sponge. Once injected into the flue gas, the activated carbon (and adsorbed mercury) must be collected in a particulate collection device. To date, the most common applications of this technology have either been 1) ahead of an electrostatic precipitator (ESP) or 2) downstream of an existing ESP but upstream of a high ratio (COHPAC) baghouse.

The first configuration mentioned above has been tested under various conditions with wide ranging results depending on contact time, fuel type, ESP size, and process conditions.

Typically, due to rapid removal of the carbon in the ESP and limited contact time with the flue gas, these applications typically achieve lower removal of mercury than carbon into baghouses. In addition, the co-mingling of activated carbon and fly ash in the ESP typically renders the fly ash unsuitable for secondary use in building materials and forces the operator to dispose of this stream.

The second application, injection into a COHPAC baghouse, is an EPRI patented technology known as TOXECON™. This process attempts to limit the co-mingling of fly ash and activated carbon by collecting a high fraction of fly ash in the ESP before injecting the activated carbon. Furthermore, because the activated carbon is collected on bag surfaces (where it can stay up to several minutes), the TOXECON™ process can typically achieve much higher removal rates than ESP injection (up to 90 percent), again depending on fuel type and process conditions. The primary drawback to this process is the added financial requirement in building a COHPAC baghouse, which will significantly affect the overall cost of mercury removal.

In either application, the mercury removal effectiveness of activated carbon injection can be enhanced when burning coals with higher sulfur content (e.g. non-PRB coals) by employing alkali sorbent injection (called ALK, typically hydrated lime injection) ahead of the carbon injection. Typically, the hydrated lime used for ALK is less expensive than the activated carbon, so the use of ACI plus ALK is a more economical process than ACI alone for a given mercury capture target.

X. Chemical Injection for Mercury Removal (Bromide Injection)

One relatively inexpensive way to capture and remove mercury from a flue gas stream is through the injection of chemical additives. Combustion of PRB coal produces primarily elemental mercury, which is insoluble in a wet flue gas desulfurization (scrubber) system. The presence of relatively high levels of elemental mercury in PRB flue gas is due to low levels of chlorine in the PRB coal, relative to other coals. High chlorine concentrations in many coals contribute to higher levels of oxidized mercury at the FGD inlet. Calcium bromide ($CaBr_2$) can be injected to oxidize mercury in PRB, and other low chlorine coals, so that the mercury can be captured in a flue gas desulfurization scrubber. There may be other considerations needed for implementing this technology, including water treatment issues.

XI. Mercury Re-emission Controls System (MRCS)

Wet scrubbers are effective at removing oxidized mercury. However, as the captured mercury may remain in a dissolved form in the scrubber slurry in the vessel, the scrubber may from time to time re-emit the mercury that was captured from the flue gas. This can cause increased levels of mercury emissions out of the stack. The addition of additives into the scrubber slurry can help prevent the occurrence of mercury re-emission by encouraging the mercury dissolved in the slurry to precipitate into a solid. This is an active research area and the use of particular scrubber additives at specific units can require further evaluations.

XII. Mercury Research Center

Construction of Southern Company's $5 million Mercury Research Center located at Gulf Power's Plant Crist in Pensacola, Florida, was completed in late 2005. This was the first mercury research facility of its kind in the world. The research facility houses major advanced control technology systems: a selective catalytic reduction system, a rotary air preheater, a cold-side electrostatic precipitator, a baghouse, and a wet limestone scrubber. Mercury capture performance is evaluated with these advanced systems on a portion of the plant's emissions using different combinations of these devices.

During the first phase of research, which began in early 2006, combinations of the five different advanced control devices were evaluated. The research facility verified which known technologies and methods work best and could facilitate the development of new methods and technologies. As research continues, still other methods may be discovered and added for further investigation. DOE- and EPRI-sponsored test programs are under development. Programs will be sponsored by other utilities, chemical suppliers, system manufacturers, and others, and Southern Company will benefit from the work and the knowledge gained.

XIII. Containment and Control Technologies for Ash Storage Areas

Several technologies are available to control or prevent a release of contaminants from ash storage areas to groundwater. The most common technologies include liners, caps, slurry walls, sheet pile walls, grouting, and *in situ* solidification and stabilization. A brief description of each technology is provided below.

Liners
A liner is a layer of impermeable or low-permeability material placed at the bottom of ash storage facilities, which prevents ash leachate from entering soil and groundwater. Liners can be constructed of compacted natural material (such as clay), synthetic materials (such as high-density polyethylene, HDPE), or composite materials (combination of synthetic and natural materials). Regulations generally require liners under new ash storage areas.

Caps
A cap is a layer of impermeable or low-permeability material placed on top of ash storage areas, to prevent surface water infiltration and resulting leachate. By preventing water movement through the ash, transport of contamination from ash to groundwater is prevented or reduced. As with liners, caps can be constructed of natural materials (for example, compacted clay), synthetic materials (HDPE), or a composite. Capping may be used in conjunction with liners or barrier walls to encapsulate a material in place.

Slurry Walls

Slurry walls are subsurface walls constructed in trenches excavated down to the top of a relatively low-permeability layer, such as clay or bedrock. The trench is filled with a slurry of materials that forms an impermeable barrier to prevent contaminant migration within the area. Slurry materials can include various mixtures of soil, bentonite clay, and/or cement.

Sheet Pile Walls

Sheet piling includes interlocking wood, concrete, or steel sectors driven into the ground or forced into pre-dug trenches, usually to the top of a relatively impermeable layer (for example, clay or bedrock). As with slurry walls, sheet pile walls form an impermeable barrier to prevent migration of contaminated water. Steel sheet pilings are the most reliable and most commonly used. Sheet piling is often used as a temporary measure of containment while dewatering or excavation, or while other containment is constructed.

Grout Curtains

A grout curtain is a method of sealing gaps in subsurface geology by injection of grout to fill voids in fractured rock, or to consolidate soil by filling the pore space. The grout material may be a Portland cement mix or any fluid material that hardens, such as a resin or sodium silicate. The grout material is injected as a pressurized fluid through holes drilled into the ground, generally in rows. Under ideal conditions, the injected fluids harden to create a relatively impermeable barrier, similar to a wall, in the subsurface.

In situ Solidification/Stabilization

Solidification/stabilization describes the technique of solidifying a contaminated soil or waste material (e.g., a sludge), to immobilize the contaminant both chemically and physically, and to reduce the leaching potential to groundwater. Solidification refers to the addition of a binder to produce a solid. Stabilization refers to the addition of a chemical agent to convert the soil or waste material to a more chemically stable form. Some additives, such as Portland cement, produce both physical and chemical changes. Large augers or equipment with rotary blades are used to mix the additives with contaminated soil or waste material.

XIV. Cooling Water Intake Screen Technology

Inclined traveling water screens (TWS) and cylindrical wedge wire screens (CWWS) will generally be the preferred water screen technologies. Both screens will allow debris handling and the design is also adaptable to minimize impingement and entrainment. Screen wash systems for the TWS and airburst systems for the CWWS can maintain screen cleanliness to an acceptable level. If needed, continuous fish and debris handling systems can also be designed to work with the TWS. As needed, fish-return technologies are also available.

XV. Water Cooling Technologies

The preferred mode of handling thermal issues at power plants can vary depending on the anticipated compliance period , temperature limits set by the facility NPDES permit, and other site-specific conditions. Wet cooling systems withdraw water to absorb heat via indirect contact with steam in a condenser. These wet cooling systems are divided into two types, based on the manner in which the cooling water is used: once-through and closed-cycle systems with cooling towers or ponds. Unlike once-through systems that continuously draw fresh cold water from a large water source, closed cycle systems pump the cooling water in a recycle loop through the condenser.

Because of the relative simplicity, the capital and operating costs for once-through systems are usually less than those for closed-cycle systems with a cooling tower. Once-through systems can also include helper cooling towers to reduce thermal load at the water discharge point, but these systems do not reduce water withdrawals. Conversion to a closed-cycle cooling water system reduces water withdrawals about 95%. Because of this, implementation of a closed-cycle system with a cooling tower is one potential method of minimizing impingement and entrainment. However, consumptive use of water will be increased from use of cooling towers and approximately 75% of the cooling water is not returned to source. Also, conversion to a closed-loop system needs to be considered carefully, since it will mean that all the materials in the loop (e.g., condenser tubes) will be exposed to water that may be significantly more aggressive than with a once-through water system.

Dry cooling systems transfer heat to the atmosphere without the use of water. Steam leaving the turbine is piped to an air-cooled, finned-tube condenser. Dry cooling has an adverse effect on power plant efficiency, requires a large area of land, and is more expensive than wet cooling. A hybrid system incorporates elements of both wet and dry cooling systems in an attempt to maximize the benefits of each. Few large-scale applications of hybrid systems exist in the United States and the cost is commensurate with that of dry cooling. Neither a dry nor a hybrid cooling system is currently considered an economically viable option in the Southeast.

XVI. Water Research Center

Designed as a collaborative effort in conjunction with Southern Company (SoCo) and the Electric Power Research Institute (EPRI), the Water Research Center will be located at the existing Plant Bowen electric generating facility owned by Georgia Power Company, a SoCo subsidiary, and will provide independent performance evaluations of technologies to address water use, withdrawal, consumption, remediation, and recycling throughout the power generation process.

The Center’s engineers and technicians will direct all research and testing at the facility. In addition to providing electric generating companies with independent testing and evaluation of current and novel technologies, the Center will also generate new information regarding current and future regulatory compliance issues related to water withdrawal, use, and discharge restrictions and will facilitate sustainable water use practices within utility operations. Testing at the Center will focus on the following key areas:

- Cooling tower and advanced cooling systems
- Zero liquid discharge systems
- Moisture recovery
- Wastewater treatment
- Solid waste landfill management
- CO_2 technology issues
- Water management modeling

The Center will be operated by Southern Research Institute, headquartered in Birmingham, Alabama.

XVII. Ash Handling Methods

The future Effluent Limitations Guidelines and Coal Combustion Residuals rules have the potential to affect fly ash handling and disposal methods at most Georgia Power units. While many units have dry ash handling capability, most use wet sluicing to ponds or settling basins as either the primary method of disposal or as back-up to the dry handling equipment. At sites where only wet handling is currently employed, complete conversions to dry handling equipment could be necessary. Where wet handling is the back-up system, the dry handling equipment could require installation of redundant components to preserve reliability of operations. Finally, systems for transporting ash to an onsite/offsite landfill or for beneficial reuse would need to be constructed. Options for transport may include truck, rail, or pneumatic.

All of Georgia Power's coal fired units currently employ wet sluicing for the transport of bottom ash from the boilers to ash ponds or settling basins. If future EPA rules limit or prohibit the discharge of bottom ash transport water, dry bottom ash handling conversions would be required at all units. Site-specific conditions at each unit will be considered in the selection of one of several methods available for removing bottom ash from the boilers, conditioning it with moisture as needed, and loading it and transporting by truck/rail to an on-site or off-site landfill or for beneficial reuse. All of the available methods for removal of bottom ash from the boiler would require extensive modification to the bottom of the boiler and the powerhouse, as well as the addition of conditioning and truck loading equipment.

Both of the rules discussed above may mandate closure of wet ash ponds for both fly ash and bottom ash.

XVIII. Landfills

As additional ash storage is needed beyond the useful life of ash ponds or as the CCR Rule may require ash ponds to be closed before their useful life is spent, landfill disposal is the likely alternative for long term ash disposal. This technology has been implemented for ash and gypsum at several Georgia Power facilities. This requires regulatory permitting, hydrogeologic/geologic studies, and large amounts of available property.

XIX. Waste Water Treatment

As discussed in section 4.2, EPA's future Effluent Limitations Guidelines are expected to require additional treatment of the wastewater discharged from scrubber systems to remove from the water certain metals that the scrubber removed from the flue gas. Most of the metals of concern may be treated to the anticipated limits by relatively conventional physical and chemical treatment, such as flocculation, coagulation, precipitation and filtration. However, the extremely low level limits for mercury will likely require expensive new cutting edge technologies for treatment. Further, the only known practicable treatment for one selenium form is microbiological treatment. Southern Company continues to research alternative treatment technologies that are more effective, economical and reliable. Several processes are being evaluated that would result in zero liquid discharge, and would avoid future wastewater permitting challenges altogether.

Low Volume Wastewater (LVW) is another category of waste stream that will require new facilities in the future if the Effluent Limitations Guidelines and/or the Coal Combustion Byproducts rules require closure of ash ponds. LVW is currently collected from many sources throughout the plant and pumped to the ash pond for co-treatment with ash transport water. The new site-specific treatment facilities could include new lined settling basins, clarification and filtration, pH adjustment, and associated pumps, piping and equipment.

ECS-APPENDIX C

HIGH-LEVEL AND LOW-LEVEL RADIOACTIVE WASTE STORAGE PLANTS HATCH AND VOGTLE

Georgia Power's sister company, Southern Nuclear Operating Company (Southern Nuclear) safely operates and maintains Plants Hatch and Vogtle in accordance with industry standards and regulatory requirements. Southern Nuclear is dedicated to maintaining the highest standards for safely handling radioactive waste to protect the public, the environment, and its workers.

High-Level Radioactive Waste (HLRW - spent fuel)

Dry Cask Storage:

Plant Hatch – currently stores spent fuel in underwater spent fuel pools and some above ground in dry casks on concrete pads until such time that the federal government licenses and builds a permanent disposal facility which can accept this waste.

Plant Vogtle – currently stores spent fuel in underwater spent fuel pools and some above ground in dry casks on concrete pads until such time that the federal government licenses and builds a permanent disposal facility which can accept this waste.

Southern Nuclear, as well as the nuclear industry, has a strong commitment to the Yucca Mountain repository as a scientifically safe and appropriate long-term solution for used nuclear fuel. The issues surrounding Yucca Mountain are political, not scientific. At the same time, the nuclear industry has adopted a used fuel management strategy that supports the research, development, and demonstration of projects to close the nuclear fuel cycle (i.e., reprocessing). It is important to note that even with reprocessing, the Yucca Mountain repository is necessary to dispose of the byproducts of nuclear fuel.

Low-Level Radioactive Waste (LLRW - trash, tools, scrap, filtering media, irradiated hardware, etc.)

Similar to the nuclear power industry, over 95 percent of the LLRW generated by Plant Hatch and Plant Vogtle continues to be buried at the Energy Solutions burial site in Clive, UT.

The remaining LLRW cannot be buried at Clive, UT. In the past it was buried at the Barnwell, SC burial facility, but that site is no longer accessible to most states including Georgia.

Hatch and Vogtle will store this remaining LLRW on the site where it was generated inside concrete shields on a concrete pad until such time as a new disposal site which can accept this waste becomes available or until some alternate means becomes available for eliminating or handling this waste. Southern Nuclear in conjunction with the nuclear industry is currently working at reducing these types of waste.