Philip C. Raymond
Executive Vice President,
Chief Financial Officer
and Treasurer

600 North 18th Street
Post Office Box 2641
Birmingham, Alabama 35291

Tel 205.257.2505
Fax 205.257.2176

ALABAMA POWER
A SOUTHERN COMPANY

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December 8, 2015

Mr. Walter L. Thomas, Secretary
Alabama Public Service Commission
RSA Union Building
100 North Union Street, Suite 850
Montgomery, Alabama 36130

Re: Final Version of Environmental Compliance Plan Associated with Rate CNP; Docket Nos. 18117 and 18416

Dear Mr. Thomas:

We are enclosing for filing an original and ten (10) copies of the final version of Alabama Power's environmental compliance plan. Included in this document are the following:

- A report on legislative and regulatory matters relevant to Alabama Power's environmental compliance activities;
- A discussion of Alabama Power's five-year projections on capital, including cost of removal for coal combustion residual facilities, and O&M expenditures related to environmental compliance activities; and
- A detailed summary of Alabama Power's capital placed in service and O&M expenditures scheduled for the upcoming environmental cost year.

If the Commission or its Staff has any questions concerning this information, please do not hesitate to contact the undersigned or Mr. Nick Sellers at (205) 257-3111, who is the designated Company individual under Rule 10 of the Special Rules.

Yours very truly,

Philip C. Raymond
Executive Vice President,
Chief Financial Officer and Treasurer

Enclosures

cc: (with enclosures)
Commissioner Twinkle Andress Cavanaugh
Commissioner Jeremy H. Oden
Commissioner Chris "Chip" Beeker, Jr.

Secretary of the Alabama Public Service Commission
Mr. Walter L. Thomas, Jr. (11)

Executive Director and
Chief Administrative Law Judge
The Honorable John A. Garner

Director, Electricity Policy Division
Mr. John D. Free

Office of the Attorney General
Ms. Olivia W. Martin

December 8, 2015

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REGULATORY AND LEGISLATIVE UPDATE

The following discussion provides a regulatory and legislative update on environmental issues affecting Alabama Power Company (**Alabama Power** or **Company**), including acid rain and interstate transport, ambient air quality standards, regional haze (visibility), hazardous air pollutants, climate change, water initiatives, toxics release inventory, and coal combustion residuals. Environmental compliance requirements affecting Alabama Power are administered by the U.S. Environmental Protection Agency (**EPA**), the Alabama Department of Environmental Management (**ADEM**), and other state and local authorities. In addition to the updates provided, Alabama Power has included, as it customarily does, background information on a number of regulatory and legislative programs that have given and continue to give rise to the environmental compliance strategies employed by the Company. While the Federal statutes regarding environmental compliance have not been substantially altered in many years, multiple new regulations continue to be promulgated in order to implement various provisions of those laws. Major EPA regulations for the electric utility industry often undergo judicial review, and courts play an increasingly significant role in the final outcome of regulations through their interpretation of the relevant federal statutes as well as their review of the regulations implementing those statutes.

ACID RAIN REQUIREMENTS

The Acid Rain Program was implemented under Title IV of the Clean Air Act Amendments (**CAAA**) of 1990. This program required significant reductions in the emissions of sulfur dioxide (**SO_2**) and nitrogen oxides (**NO_x**), which can lead to the formation of acid rain. For SO_2, the Acid Rain Program ushered in a new and innovative "cap and trade" concept that established a permanent nationwide cap on the total amount of SO_2 that may be emitted by electric power plants. The program set a specific number of SO_2 "allowances" (one allowance being equivalent to one ton of emitted SO_2) that achieves the national goal for SO_2 reductions. Allowances can be banked, traded and sold. This market-based program allows affected sources to design and implement compliance strategies at lower costs while achieving the desired environmental goals. Each generating plant affected by the Acid Rain Program must have sufficient allowances to cover its annual SO_2 emissions. The program requires rigorous emissions monitoring and reporting protocols to ensure accuracy and accountability, to support the allowance trading element, and to achieve the desired program results. Alabama Power's compliance strategies for the Acid Rain Program have included switching to lower sulfur coals, purchasing, trading and banking SO_2 allowances, as well as installing emissions control equipment. Every year, Alabama Power has maintained adequate SO_2 allowances to comply with the Acid Rain Program.

The requirements of the Acid Rain Program have been implemented in two phases. Phase I requirements became effective for SO_2 on January 1, 1995. EPA allocated SO_2 allowances to Phase I units using a historical fuel consumption (i.e., heat input) baseline and a specific emission rate of 2.5 pounds of SO_2 per million Btus of heat input. Due to litigation involving the final rules, the effective date for Phase I NO_x compliance was delayed one year until January 1, 1996. The Phase I limits for NO_x were 0.50 and 0.45 pounds of NO_x per million Btus of heat input for dry-bottom wall-fired and tangentially-fired boilers, respectively. Alabama Power's coal-burning units have complied with the Acid Rain Program annual NO_x emission rate limits since those limits became effective in 1996.

The Acid Rain Program's Phase II requirements for both SO_2 and NO_x became effective on January 1, 2000. The limits for Phase II affect more units and are more stringent than those under Phase I. EPA allocated SO_2 emission allowances (again based upon specific formulas) to all affected units above 25 megawatts in size with an allocation factor of 1.2 pounds of SO_2 per million Btus of heat input. The final Phase II NO_x rules set the limits for the three general boiler and burner types and designs owned and operated by Alabama Power at 0.46 pounds of NO_x per million Btus of heat input for wall-fired boilers, 0.40 pounds of NO_x per million Btus of heat input for tangentially-fired boilers, and 0.68 pounds of NO_x per million Btus of heat input for the more difficult to control cell burner-fired boilers. Alabama Power's compliance strategies for the Acid Rain Program NO_x limitations have included installing low-NO_x burner and combustion control technologies and selective catalytic reduction systems in conjunction with system-wide NO_x emission rate averaging plans.

AMBIENT AIR QUALITY STANDARDS

The major United States law driving federal air regulations is the Clean Air Act (**CAA** or **the Act**). The cornerstone of the CAA is the establishment and attainment of the National Ambient Air Quality Standards (**NAAQS** or **standards**) for the following six pollutants: ozone, particulate matter, sulfur dioxide, lead, carbon monoxide and nitrogen dioxide. The CAA requires that EPA determine what concentration of each of these six specific pollutants in the ambient (i.e., outside) air is protective of human health and welfare within a margin of safety. Fossil-fired power plants emit some of these air pollutants directly, while some of these pollutants can also combine with other substances in the atmosphere to form "secondary" pollutants such as "fine" particulate matter and ozone.

Geographic areas where ambient levels of any of these pollutants exceed the NAAQS are designated as "nonattainment" areas. States that have nonattainment areas are required by the

CAA to develop and implement State Implementation Plans (**SIPs**) that include emission control strategies designed to bring these areas into attainment with the NAAQS that are not being met. EPA must approve these SIPs, and if a state fails to adopt a SIP, EPA must promulgate a Federal Implementation Plan (**FIP**) in lieu of the SIP.

Once EPA sets a NAAQS for a pollutant, the CAA requires EPA to review the NAAQS every five years to determine if a revision is necessary. Since 1997, these reviews have resulted in multiple, significant changes to the ozone, lead, particulate matter, nitrogen dioxide, and sulfur dioxide NAAQS. The vast majority of costs for emission controls incurred by Alabama Power are attributable to the implementation of these increasingly stringent air quality standards.

<u>1-Hour Ozone Standard</u>

Historically, the most pervasive and difficult ambient air pollutant to reduce has been ozone, with many major urban areas across the country (including Birmingham) failing to meet the 1-hour ozone standard (0.12 parts per million or ppm) for many years. As discussed below, EPA established a more stringent 8-hour ozone standard in 1997, (**the 1997 8-hour ozone standard**) and eventually revoked the 1-hour standard in June 2005 (the terms **1-hour** and **8-hour** refer to the time period over which the air quality monitor data is averaged). However, emission reduction regulations addressing the 1-hour ozone standard remain effective under the Alabama SIP for Birmingham ozone and affect two Alabama Power plants.

By way of background, Jefferson and Shelby Counties were originally classified as a 1-hour ozone nonattainment area by EPA on March 3, 1978. The CAAA of 1990 required most states with then existing 1-hour ozone nonattainment areas to submit by November 1994 revised SIPs that demonstrated attainment of the standard by their designated attainment year. Most affected states were unable to demonstrate attainment and could not submit revised SIPs by the deadline.

EPA thus allowed states to delay the SIP submittals for approximately two years, provided states finalized plans for certain emission reduction mandates and agreed to participate in a collaborative effort to evaluate regional controls for NO_x emissions that could contribute to attainment of the ozone standard across an entire region (for Alabama, the eastern United States).

The collaborative effort led to the formation of the Ozone Transport Assessment Group (**OTAG**), an organization of 37 states east of and bordering the Mississippi River, plus Texas, Kansas, Nebraska, Oklahoma and the Dakotas. OTAG evaluated certain regional NO_x and volatile organic compounds (**VOC**) controls and their potential for reducing ozone in the eastern United States. OTAG presented its final recommendations to EPA in June 1997. The final recommendations presaged EPA's Regional NO_x SIP Call rule, which required additional NO_x emission reductions for utilities and large industrial sources as a measure to address regional transport of this ozone precursor.

The CAAA of 1990 prescribed a 1-hour ozone standard attainment date of 1993 for the Birmingham ozone nonattainment area (Jefferson and Shelby Counties). Birmingham recorded air quality data that demonstrated attainment of the standard in 1993, and ADEM submitted a request to EPA in March 1995 to redesignate Birmingham to attainment for the 1-hour ozone NAAQS. However, before EPA acted on ADEM's request, Birmingham-area ozone monitors recorded ozone air quality data that violated the 1-hour standard. EPA subsequently denied ADEM's redesignation request in September 1997, and later in 2000 issued a **SIP Call** requiring Alabama to submit a plan that would provide for attainment of the 1-hour ozone standard in Birmingham. ADEM submitted a 1-hour ozone SIP in November 2000, and EPA approved the plan in November 2001. EPA allowed Alabama until May 2003 to enforce the SIP requirements needed to attain this ozone standard.

ADEM's rules addressing the 1-hour ozone standard require Alabama Power Plants Gorgas and Miller to achieve a 0.21 pounds of NO_x per million Btus of heat input 30-day rolling average limit during the ozone season. To meet this mandate, Alabama Power installed, in addition to previously-installed controls, selective catalytic reduction (**SCR**) technology at Gorgas 10 and Miller 3-4, and combustion controls at other Gorgas units. (In 2005, SCRs were installed at Miller 1-2 for compliance with the NO_x Budget Trading Program, but these controls also contributed to compliance with the 1-hour ozone Alabama SIP requirements.)

On March 12, 2004, EPA approved the redesignation of the Birmingham ozone nonattainment area to 1-hour ozone attainment based on the air quality data recorded for the area from 2001-2003. Prior to this approval, the Sierra Club had initiated litigation in the United States Circuit Court of Appeals for the District of Columbia (**D.C. Circuit**) seeking higher (i.e., more punitive) nonattainment status for some areas across the country, including Birmingham. The D.C. Circuit concluded that EPA failed to exercise its duty to make a final ozone determination for classifying Birmingham (and other areas) by May 15, 1994, as prescribed by the CAAA of 1990. In November 2002, in response to the court's order, EPA determined that Birmingham did, in fact, attain the 1-hour ozone standard by November 15, 1993, the date required by the CAAA of 1990. Consequently, in 2002 Birmingham retroactively met the 1-hour standard as of 1993, and again achieved (and officially redesignated to attainment) the 1-hour standard in March 2004. Unfortunately, attainment was short lived, as in April 2004 Birmingham was designated ozone nonattainment for the more stringent 1997 8-hour ozone standard (discussed later).

<u>NO_x Budget Trading Program</u>

In September 1998, EPA issued the Regional NO_x SIP Call rule, which required 22 states (including Alabama) and the District of Columbia to submit SIPs addressing regional transport of the ozone precursor NO_x. The Regional NO_x SIP Call rule was a cap and trade program and was also referred to as the NO_x Budget Trading Program (**NBP**). The NBP required NO_x emission reductions sufficient to meet unique NO_x emission budgets specified for each affected state. The utility budgets were based upon projected electricity generation for 2007 (using EPA assumptions that under-predicted actual growth in some cases) and NO_x emissions at approximately 0.15 pounds of NO_x per million Btus of heat input for coal-fired units.

Final NBP SIPs were originally required by September 1999, with the final compliance deadline for utilities and large industrial sources set for May 1, 2003. However, the rule was challenged and in May 1999, the D.C. Circuit issued an order staying the September 1999 SIP submittal deadline until "further order of the court." In March 2000, the court largely upheld the Regional NO_x SIP Call rule and cleared the way for EPA to implement the program. Even so, the court vacated the rule for Georgia, Missouri and Wisconsin, and EPA was required to submit a revised rule for the northern two-thirds of Georgia and the eastern half of Missouri. As part of its February 2002 proposal, EPA excluded the southern one-third of Alabama, along with the southern one-third of Georgia, because modeling results did not show an impact on any out-of-state nonattainment area from sources in these regions. As a result of further litigation and its final rule reconsiderations, EPA eventually rescinded the Regional NO_x SIP Call rule as applied to all of Georgia in April 2008.

The litigation before the D.C. Circuit resulted in an extension of the compliance date for utilities and large industrial sources from May 1, 2003 to May 31, 2004, for all remaining affected states. The Alabama NBP SIP rules were finalized in February 2001 and approved by EPA in July 2001. In addition to the SCRs installed to meet the ADEM 1-hour ozone standard requirements, Alabama Power installed SCRs at Miller 1-2 and Gaston 5 as well as combustion controls at

Greene County 1-2 for compliance with the NBP. With the promulgation of the Clean Air Interstate Rule (discussed later), the NBP ended in 2008.

8-Hour Ozone Standards

On July 18, 1997, EPA promulgated new ambient air quality standards for ozone. Compared with the original 1-hour ozone standard, the 1997 8-hour ozone standard has a lower ozone concentration level (0.08 ppm vs. 0.12 ppm) and a longer averaging period (8 hours vs. 1 hour). The two standards also use different calculation methodologies to determine attainment. Attainment of the 8-hour standard is determined by the average of the fourth-highest concentration of each year measured over a 3-year period. The net effect of these changes is that the 1997 8-hour standard is significantly more stringent than the 1-hour standard.

On May 14, 1999, the D.C. Circuit remanded the 1997 8-hour ozone and particulate matter standards to EPA for reasons involving constitutionality, the nonattainment classification scheme, and ultraviolet-B (UVB) health "disbenefits." EPA appealed the first of these two rulings to the United States Supreme Court. On February 27, 2001, the Supreme Court upheld the constitutionality of the standards, but rejected EPA's implementation plan for the 1997 8-hour ozone standard and remanded the standard to the D.C. Circuit for further review. On March 26, 2002, the lower court dismissed all remaining challenges to the standard. On January 6, 2003, EPA published a final rule that responded to the court remands related to the beneficial effects of ozone in preventing UVB-induced skin cancers and cataracts. EPA determined that these effects were too uncertain to warrant a change to the standard.

In April 2004, EPA designated the Birmingham area (Jefferson and Shelby Counties) nonattainment for the 1997 8-hour ozone standard. The Birmingham nonattainment area was classified as a **Basic** nonattainment area, with an attainment deadline of June 15, 2009. The

Alabama SIP containing 1997 8-hour ozone attainment demonstrations and control requirements for Birmingham was due June 15, 2007. However, ozone monitoring data for 2003-2005 showed that Birmingham was achieving the 1997 8-hour standard. ADEM requested that EPA redesignate the Birmingham area to ozone attainment based upon the most current air quality data. EPA approved the request, and the Birmingham area became attainment for the 1997 8-hour ozone standard effective June 12, 2006. This action eliminated the need for an 8-hour attainment SIP for Birmingham, but a **Maintenance Plan** was required under the CAA, and one was approved as part of the redesignation process. The Maintenance Plan demonstrates that the standard will continue to be met after attainment designation.

Subsequent to the EPA ozone attainment redesignation, a Birmingham area air quality monitor began recording violations of the 1997 8-hour standard. This event required ADEM to activate the Maintenance Plan in order to address the ozone monitor violations (i.e., ADEM must take actions to ensure the standard would again be attained). ADEM revised air permits for two industrial facilities, requiring additional NO_x emission reductions in order to satisfy Maintenance Plan provisions.

While many areas in the United States were still struggling to meet the 1997 8-hour ozone standard, EPA lowered the ozone standard once again. On March 27, 2008, EPA established the 2008 8-hour ozone standard, which increased the stringency of the 8-hour ozone standard from 0.08 ppm (effectively 0.084 ppm due to rounding) to 0.075 ppm. Legal challenges were filed by industry groups as well as the State of Mississippi, charging that the 2008 standard was overly stringent. On the other hand, numerous other states and environmental groups claimed that the 2008 standard was not stringent enough. The cases were consolidated as *Mississippi v. EPA* in the D.C. Circuit. The State of Alabama filed a motion to intervene in support of the petitioner

State of Mississippi. Shortly after a change in the Administration, EPA requested the D.C. Circuit suspend briefing pending an EPA decision whether to reconsider the 2008 standard. The court granted this request in March 2009. In September 2009, EPA announced that it would reconsider the 2008 ozone standard. On January 6, 2010, EPA proposed to increase the stringency of the standard by lowering the level from 0.075 ppm to a level in the range of 0.060 to 0.070 ppm. Such a revision would be expected to result in a large number of new nonattainment areas throughout the United States. Based on ozone monitoring data at the time, a level of 0.070 ppm was projected to result in 75 percent of monitored counties across the country being nonattainment, and a level of 0.060 ppm was projected to result in 96 percent of monitored counties being nonattainment.

Area designations for the 2008 ozone standard were initially slated for March 2010. However, with the Administration's decision to reconsider the standard, EPA announced its intention to stay that process and finalize designations for a potentially revised ozone standard. On September 2, 2011, after numerous delays finalizing a revision, the President instructed EPA to withdraw its reconsideration of the 2008 ozone standard. EPA subsequently resumed implementation of the 2008 ozone standard of 75 ppb and finalized initial designations on April 30, 2012. No areas in Alabama were designated as nonattainment for the 2008 standard. Litigation of the 2008 standard, which had been held in abeyance, resumed as well. On July 23, 2013, the D.C. Circuit issued its opinion in the matter and denied the petitions for review by industry, state and environmental groups challenging the standard. The court did not require EPA to change the 2008 ozone standard. Subsequently, petitions were filed requesting Supreme Court review of the standard, and on September 29, 2014, the Supreme Court denied these petitions.

When EPA missed its five-year deadline for reviewing the 2008 ozone standard for possible revision, environmental groups filed a lawsuit in June 2013 to force EPA to complete the review. On April 30, 2014 the United States District Court in Northern California ordered EPA to propose a rule by December 1, 2014 and issue a final rule by October 1, 2015. On November 26, 2014, EPA issued a proposed rule to revise the 8-hour ozone standard down to a level between 0.070 and 0.065 ppm, while also accepting comments on levels down to 0.060 ppm as well as retaining the 2008 standard. On October 1, 2015, EPA finalized a rule establishing a new ozone standard of 0.070 ppm. Based on current ozone monitoring data (2012 – 2014), 33 percent of monitored counties in the United States exceed an ozone standard of 0.070 ppm. While designations for the new standard will be based in part on future ozone monitoring data, all of Alabama currently meets the new standard based on 2012 – 2014 monitor data.

In that event there are future nonattainment designations in Alabama, ADEM would be required to develop SIPs that give reasonable assurance that the standard will be achieved. As in the past, the courts are expected to continue to play a significant role in the establishment of any new ozone standard and its implementation.

<u>Fine Particle Standards</u>

On July 18, 1997, EPA also promulgated new ambient air quality standards for fine particulate matter. Fine particulate matter is a general term used for a mixture of solid particles and liquid droplets in the air that have aerodynamic diameters less than 2.5 micrometers (**PM2.5**). The 1997 standards established 24-hour and annual standards for PM2.5. The 1997 PM2.5 standards were delayed by challenges in various courts, but were ultimately largely upheld. Specifically, as with the 1997 8-hour ozone standard, the D.C. Circuit remanded, on constitutional grounds, the 1997 PM2.5 standards to EPA for redevelopment. EPA appealed the decision to the Supreme Court, which upheld the constitutionality of the PM2.5 standards and returned the case to the D.C. Circuit for consideration of whether the levels of the standards properly reflect what is requisite (i.e., "sufficient, but not more than necessary") to protect public health. On March 26, 2002, the lower court dismissed all remaining challenges to the 1997 PM2.5 standards.

In February 2004, ADEM recommended to EPA annual PM2.5 nonattainment areas in Alabama. After considering additional data, ADEM later amended its annual PM2.5 nonattainment area recommendation to include only Jefferson County, where air quality data showed the PM2.5 annual standard of 15 micrograms per cubic meter was not being met by only two of the county's eight PM2.5 monitors (all areas in the state were meeting the 1997 24-hour standard). EPA disregarded ADEM's recommendation and included all of Jefferson and Shelby Counties in the final nonattainment designations, which became effective April 5, 2005. Small areas of Walker and Jackson Counties that contain electric power generating plants were also designated nonattainment for the annual PM2.5 standard (Jackson County is part of the larger Chattanooga, Tennessee nonattainment area).

After extensive analysis, ADEM developed an annual PM2.5 attainment SIP for the Birmingham area and submitted it to EPA in May 2009. Primarily, ADEM's SIP requires PM2.5 emission reductions from local facilities in the vicinity of the Birmingham air quality monitors that are violating the standard and relies on utility emission reductions realized from the Clean Air Interstate Rule (discussed below).

On September 21, 2006, EPA issued a revision to the PM2.5 standards. With this action, EPA retained the current annual standard, while lowering the 24-hour PM2.5 standard by nearly 50 percent (from 65 to 35 micrograms per cubic meter). On October 8, 2009, EPA issued final area designations for the 2006 24-hour PM2.5 standard. The Birmingham area was designated nonattainment for this standard with the geographic footprint identical to the annual PM2.5 standard nonattainment area (i.e., Jefferson, Shelby and part of Walker Counties). ADEM's SIP, which was designed to bring the area into attainment with the 2006 24-hour PM2.5 standard, was expected to be due to EPA by December 2012. However, air quality data from 2007-2009 showed attainment of the 24-hour standard of 35 micrograms per cubic meter. Accordingly, ADEM prepared and submitted to EPA in April 2010 a 24-hour PM2.5 Redesignation Request and Maintenance Demonstration for Birmingham. In a final action in September 2010, EPA determined that the Birmingham area had indeed attained the 2006 24-hour PM2.5 standard; however, EPA did not officially redesignate Birmingham to attainment or approve the Maintenance Plan. Similarly, air quality data for the 2008–2010 period showed that the Birmingham area was also meeting the 1997 annual PM2.5 standard of 15 microgram per cubic meter. ADEM requested redesignation for that standard in March 2011. On June 29, 2011, EPA determined that the Birmingham area had attained the 1997 annual PM2.5 standard, but similar to its action in September 2010, the agency did not redesignate Birmingham to attainment. These EPA determinations suspend the requirements for ADEM to submit an attainment demonstration and other SIP elements as long as Birmingham continues to meet the standard. However, the most burdensome and punitive requirements of nonattainment are not relieved for regulated sources until redesignation to attainment is finalized by EPA. On November 10, 2011, EPA proposed to redesignate the Birmingham area to attainment for both the 24-hour and the annual PM2.5 standards. On January 22, 2013, EPA published the final rule redesignating the Birmingham area to attainment for the 1997 annual PM2.5 NAAQS. And on January 25, 2013, EPA published the final rule redesignating the Birmingham area to attainment for the 2006 24-hour PM2.5 NAAQS.

Litigation of the 2006 PM2.5 standards was initiated in the D.C. Circuit. Numerous states and environmental groups challenged the levels of the standard, specifically claiming that EPA should have increased the stringency of the annual standard. In February 2009, the court found that EPA inadequately explained its actions concerning the 2006 24-hour PM2.5 standard and remanded to EPA its decision to retain the annual standard. EPA announced plans to accelerate the typical five year NAAQS review cycle for the PM standards. Subsequently, on June 29, 2012, EPA proposed to revise the annual PM2.5 standard with a more stringent standard. On December 14, 2012, EPA finalized revisions to the NAAQS for PM2.5, lowering the annual standard to 12 micrograms per cubic meter while leaving 24-hour standard unchanged. In March 2013, several industries filed petitions for judicial review of the new 2012 PM2.5 standards, but the D.C. Circuit upheld them by order issued May 9, 2014.

In an April 16, 2013 memorandum, EPA informed states that recommendations for areas that do not meet the 2012 PM2.5 annual standard were due to EPA by December 13, 2013, and that EPA would finalize the designations by December 13, 2014. EPA also indicated that areas not meeting the standard would have six years after designation to come into attainment. With EPA's concurrence, ADEM did not submit its recommendations by December 13, 2013 in order to incorporate 2013 air quality data in its recommendation. Accordingly, on March 3, 2014, the State of Alabama recommended to EPA that all counties in Alabama be designated as attainment for the 2012 annual PM NAAQS. On August 19, 2014, EPA informed Alabama that it intended to designate all of the state as "unclassifiable/attainment" except for the Phenix City area in Russell County. EPA's reasoning was that Phenix City is part of the metropolitan area that includes Columbus, Georgia, and the Georgia monitor had insufficient air quality data to make a determination. EPA deferred the designation for Columbus-Phenix City to allow time for adequate air quality monitoring needed for a designation. On January 15, 2015, EPA finalized designations for most areas in the United States. All of Alabama was designated attainment for the 2012 PM2.5 annual standard, except for Russell County where designation was deferred. After air quality monitoring data necessary for designation was collected, EPA designated Russell County attainment for the 2012 PM2.5 annual standard on April 7, 2015, completing designations for Alabama.

Clean Air Interstate Rule

EPA signed the Clean Air Interstate Rule (**CAIR**) on March 10, 2005. The rule required major reductions – far beyond those required by the Acid Rain Program – of SO_2 and NO_x emissions to address the transport of emissions in the eastern United States that significantly interfere with attainment of the PM2.5 and ozone standards in downwind states.

Implementation of the emission reductions from CAIR involved two phases. The first phase of NO_x compliance began on January 1, 2009, and called for an approximate 50 percent reduction from 2003 NO_x emissions in CAIR affected states. The first phase of SO_2 compliance began on January 1, 2010, requiring an approximate 50 percent further reduction in SO_2 emissions. The second phase of NO_x and SO_2 compliance was set to begin in 2015 and required an approximate 65 percent reduction in NO_x and 70 percent reduction in SO_2 from 2003 emissions or allocations. For affected states, CAIR set permanent caps on emissions and provided for annual SO_2, annual NO_x, and seasonal NO_x allowance trading programs. CAIR leveraged off of the Acid Rain Program by discounting SO_2 allowances for sources in CAIR-affected states to achieve the desired reductions. Further, each affected state was given a NO_x "budget" to meet. The state determines whether to allow participation in the allowance trading programs for NO_x and the method for allocating its NO_x allowances to its affected sources. ADEM initially submitted the Alabama CAIR SIP rules to EPA for approval in September 2006. ADEM submitted CAIR SIP updates in November 2006 and March 2007 to comply with EPA revisions to the federal rule. EPA approved Alabama's CAIR SIP in October 2007.

Various states and regulated industries filed petitions challenging particular aspects of CAIR in the D.C. Circuit. In July 2008, the court vacated CAIR in its entirety, and remanded it to EPA for further action consistent with its opinion. The court stated that EPA's CAIR approach "is fundamentally flawed" and directed EPA to redo its analysis "from the ground up" citing foundational problems with basic aspects of the rule such as trading, maintenance of NAAQS, compliance deadlines, and leveraging off of Acid Rain Program allowances.

In response to an EPA petition for rehearing of the CAIR vacatur, the court requested briefs from petitioners and EPA regarding harms to the public health that would be caused by vacatur of CAIR. In December 2008, upon consideration of these briefs, the court decided to remand CAIR to EPA without vacatur just days before compliance was set to begin, thereby leaving the rule and its compliance obligations in place until replaced by a new rule developed under remand. Therefore, compliance with the NO_x and SO_2 elements of CAIR began on January 1, 2009, and January 1, 2010, respectively, as specified in the original EPA rule. Subsequent to the remand decision, EPA stated that it intended to propose a CAIR replacement rule in early 2010 and finalize that rule in early 2011. The "on, off, and back on again" CAIR, coupled with an unknown (at the time) CAIR replacement rule, was a significant complicating factor for Alabama Power in compliance planning – especially considering the long lead times that many emission control projects require. In addition, emission reductions realized from CAIR were being relied on by ADEM in the Birmingham annual and 24-hour PM2.5 SIPs and the Clean Air Visibility Rule (discussed in the next section).

CAIR was also the basis for EPA's denial of North Carolina's CAA Section 126 petition, which called for EPA to require thirteen states to reduce NO_x and SO_2 emissions to assist North Carolina in achieving and maintaining ozone and PM2.5 standards. Section 126 of the CAA allows for a state that believes it is significantly impacted by emissions from other states to have EPA require emission reductions from sources in those impacting states. North Carolina's Section 126 petition was being litigated in a separate proceeding in the D.C. Circuit, with Alabama being one of the named states alleged to impact North Carolina's air quality. The absence of CAIR could have a major bearing on the litigation. In fact, the D.C. Circuit specifically pointed out the Section 126 option for states in its CAIR decision. Conceding that the court's decisions regarding CAIR eliminated or fundamentally changed the legal basis for EPA's denial of North Carolina's petition, EPA asked the court to allow it to reconsider its denial. In March 2009, the court agreed that a remand to EPA for reconsideration was in order in light of the remand of CAIR. The court did not set a deadline for EPA to act, but stated that EPA's reconsideration should be "expeditious." There has been no further action from EPA to date, and this issue has not been completely resolved.

The Company has installed scrubbers at Plants Barry, Gaston, Gorgas and Miller, with the SO_2 emission reductions from these scrubbers intended not only to meet CAIR (and its replacement) and other programs (such as the Acid Rain Program), but also to address local attainment of the PM2.5 standards. The Company has also installed SCRs on its largest coal-fired units. CAIR was ultimately replaced with the Cross-State Air Pollution Rule (discussed below) and its compliance obligations began on January 1, 2015.

<u>Cross-State Air Pollution Rule</u>

On July 6, 2010, EPA signed a new proposed Transport Rule – the replacement rule for CAIR. EPA proposed one approach and received comments on two alternatives. All three approaches set an emissions limit (or budget) for each affected state and sought to obtain SO_2 and NO_x emission reductions from power plants in 31 eastern states. Compliance would begin in 2012 and become more stringent in 2014. Under EPA's "preferred" approach, unlimited interstate trading (for three allowance programs: annual SO_2, annual NO_x and seasonal NO_x) would be allowed in 2012 and 2013, but would become limited in 2014. EPA intended to propose a second Transport Rule in 2011 to address new, more stringent NAAQS.

On July 7, 2011, EPA finalized the Transport Rule with a new name, the Cross-State Air Pollution Rule (**CSAPR**). CSAPR was designed to reduce PM2.5 and ozone levels in ambient air across a wide region. SO_2 and NO_x react in the atmosphere to form PM2.5, and NO_x and VOCs react in the atmosphere to form ozone. These compounds can be transported long distances, thereby impacting downwind areas' ability to meet these NAAQS.

CSAPR was intended to replace CAIR in its entirety in response to the 2008 remand of the CAIR rule by the D.C. Circuit. According to EPA, CSAPR affected 3,632 electric generating units at 1,074 coal-, gas-, and oil-fired facilities in 28 eastern states. CSAPR set state budgets (i.e., emission limits) and allowed intrastate allowance trading, but only very limited interstate trading (although EPA delayed restrictions on interstate trading until 2014). As in the case with CAIR, there were three separate allowance programs affecting Alabama: annual SO_2, annual NO_x and seasonal NO_x. (Not all states are affected by all allowance programs.) Compliance with the first phase of CSAPR was scheduled to begin on January 1, 2012. However, on December 30, 2011, less than 48 hours before compliance was set to begin, the D.C. Circuit issued a stay of CSAPR and ordered EPA to continue to administer CAIR while CSAPR was stayed.

On August 21, 2012, the D.C. Circuit vacated CSAPR, holding that CSAPR exceeded EPA's statutory authority by requiring upwind states to reduce emissions by more than their own significant contribution to nonattainment in other states and failing to allow states the initial opportunity to implement, through SIPs, the emission reductions required by EPA in CSAPR. The court directed EPA to continue to administer CAIR pending completion of a rulemaking to replace CSAPR with a valid rule.

On March 29, 2013, EPA filed a petition with the Supreme Court requesting review of the CSAPR vacatur, and on June 24, 2013 the court granted the request for review. On April 29, 2014, the Supreme Court reversed the D.C. Circuit's decision vacating CSAPR (while leaving the stay in effect) and remanded the case back to the D.C. Circuit for further proceedings. On June 26, 2014 EPA filed a motion to lift the 2011 stay of CSAPR and requested that the court toll compliance deadlines by three years. On October 23, 2014, the D.C. Circuit lifted the stay of CSAPR. Although some additional legal challenges remained unresolved, Phase I of CSAPR began on January 1, 2015, replacing CAIR and implementing new allowance programs for annual SO_2, annual NO_x, and seasonal NO_x.

With respect to Phase II of CSAPR, on July 28, 2015 the D.C Circuit issued a decision in the litigation on remand from the Supreme Court. Relying on the Supreme Court's finding that EPA cannot require an upwind state to reduce emissions by more than the amount necessary to achieve attainment in every downwind state to which it is linked, the D.C. Circuit held invalid certain Phase II CSAPR emission budgets. The court ruled that the CSAPR Phase II SO_2 emission budgets for Alabama, Georgia, South Carolina and Texas were invalid and as well as ozone season NO_x budgets for eleven states (Alabama was not a named state for the invalid NO_x emission budgets). The court remanded CSAPR without vacating any part of the rule for EPA to reconsider these emission budgets. Further, the court rejected all other challenges to CSAPR. On November 17, 2015, EPA announced a proposal to reduce the ozone season NO_x budgets for 23 states, including a significant reduction for Alabama's budget beginning in 2017. The Company is presently reviewing this proposal and assessing potential impacts.

The installation by Alabama Power of SCRs and scrubbers has helped to ensure compliance with the continued administration of CAIR and will help ensure compliance with CSAPR and any subsequent additional transport rule EPA promulgates. Although somewhat hampered by the regulatory uncertainty associated with multiple overlapping and rapidly evolving regulations, along with the protracted litigation, the Company has continued to evaluate its remaining smaller fossil fuel-fired electric generating units for possible additional emission controls, conversion to other fuels, and/or retirement/replacement.

NO_2 Standards

In February 2010, EPA issued a final rule that revises the NAAQS for Nitrogen Dioxide (**NO_2**). EPA retained the existing annual standard of 53 ppb and added a new 1-hour standard of 100 ppb. The rule requires new roadside and community wide ambient air quality monitoring in larger urban areas. The Jefferson County Department of Health installed two NO_2 ambient air quality monitors in Birmingham to meet this requirement. While EPA's intention is to focus on mobile source emissions near major roadways, the new standard could also affect other sources of NO_x emissions. In June 2010, EPA provided guidance for air quality modeling assessments associated with the new standard. This guidance specifies the use of unusually conservative (stringent) procedures, particularly in the permitting of new or modified sources.

In February 2012, EPA designated all areas of the country as "unclassifiable/attainment" for the new 1-hour NO_2 standard. Petitions for reconsideration and legal challenges of the final rule were filed in the D.C. Circuit and on July 17, 2012, the D.C. Circuit upheld the revised NO_2 standards. Petitions for review filed with the Supreme Court were ultimately denied, effectively ending litigation.

SO_2 Standards

In June 2010, EPA issued another final rule that revised the NAAQS for Sulfur Dioxide (SO_2). EPA established a new 1-hour standard of 75 ppb and revoked the existing 24-hour and annual standards (effective one year after final area designations for the new standard). The new standard would be implemented through a combination of ambient air quality monitoring and computer modeling, deviating from the traditional method of establishing attainment based only on air monitoring data. Numerous states, industries and groups challenged the SO_2 NAAQS rule, but on July 20, 2012, the D.C. Circuit upheld the revised SO_2 standard. A petition for review filed with the Supreme Court was also denied in January 2013.

In June 2011, ADEM recommended to EPA that all areas in Alabama be designated "unclassifiable" for the new 1-hour SO_2 standard. EPA did take stakeholder input on a provision of the rule that required major SO_2 sources (including all Alabama Power coal-fired power plants) to be modeled and has delayed attainment designations. (This new standard would make it increasingly difficult to operate coal-fired electric generating units without low sulfur coal or scrubbers that reduce SO_2 emissions.) On July 25, 2013, EPA designated 29 areas in 16 states as "nonattainment" for the 2010 SO_2 standard. No areas in Alabama were designated in this round of designations.

Environmental groups filed suit in the U.S. District Court for the Northern District of California over EPA's failure to complete designations for the entire country by the CAA statutory deadline. On December 6, 2013, the court found liability based on an EPA concession that it had failed to meet the deadline. On June 2, 2014, EPA proposed a consent decree in the *Federal Register* that had been negotiated with environmental groups. Several states filed comments opposing the proposed consent decree, including Alabama. On October 14, 2014 oral argument was presented before the U.S. District Court for the Northern District of California, and on March 2, 2015 the court accepted the consent decree as an enforceable order. The court's order directs EPA to complete designations for the SO_2 NAAQS in three additional rounds by prescribed dates. Alabama Power's Greene County plant was originally affected by the decree. However, Alabama Power's decision to convert the boilers on Units 1 and 2 to fire only natural gas rendered the consent decree inapplicable to Greene County.

In a simultaneous regulatory action regarding SO_2 NAAQS designations, EPA proposed a data requirements rule (**DRR**) on April 17, 2014. On August 10, 2015 the DRR was finalized and a schedule established for air agencies to characterize SO_2 air quality and to provide that air quality data to EPA. By January 15, 2016, air agencies must submit to EPA a list identifying SO_2 emitting facilities around which air quality is to be characterized. The list must include sources with SO_2 emissions above 2000 tons per year. The DRR provides options for how states must characterize air quality around facilities on the list to show compliance with the 1-hour SO_2 NAAQS. The options are: 1) perform air quality modeling, 2) install and operate SO_2 ambient monitors, or 3) adopt federally enforceable permit limits to cap SO_2 emissions below 2000 tons per year. For facilities that choose modeling, the analysis must be submitted to EPA by January 13, 2017, and designations would be finalized by December 2017. For facilities that choose air monitoring, monitors must be appropriately sited and operational by January 1, 2017, and designations would be finalized by December 2020. Certified air quality monitoring data must be collected for 2017 through 2019. For facilities that accept limits that cap SO_2 emissions below 2000 tons per year, these limits must be effective by January 13, 2017. Alabama Power is evaluating how the DRR may impact its facilities in light of the current environmental compliance plan being implemented.

CLEAN AIR VISIBILITY RULE

The Clean Air Visibility Rule (**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 I** 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 that may be deemed necessary for each designated area to achieve "reasonable progress" toward the goal of natural conditions. Progress toward the natural visibility goal is assessed every ten years. For each of these ten-year planning periods, additional emissions reductions will be required for continuing progress in each Class I area during that period unless states demonstrate that additional measures are not needed or are not reasonable.

The BART application of CAVR is an element of the first planning period only. Among other criteria, a BART analysis and determination must consider the costs to the source and the source-specific visibility benefits from the application of BART. Under CAVR, states have the regulatory prerogative to determine whether CAIR is equivalent to BART for SO_2 and NO_x for electric generating units. In other words, CAIR-affected units would potentially not have to go through a BART analysis for SO_2 and NO_x for visibility impairment as it pertains to this rule. ADEM made the decision that CAIR is equivalent to BART for CAIR-affected units in Alabama, which was fully consistent with EPA regulations at the time. Therefore, for its named units, Alabama Power submitted BART analyses for particulate matter – the remaining visibility impairing pollutant in addition to NO_x and SO_2.

Under the rules, ten Alabama Power coal-fired units were declared BART-eligible and required to undergo a BART analysis. The named units are Barry 4-5, Gaston 5, Gorgas 10, Greene County 1-2 and Miller 1-4. Alabama Power performed the required extensive BART analyses for particulate matter and submitted the analyses to regulatory agencies in August 2006. The results showed that none of the Alabama Power units met the thresholds for causing or contributing to visibility impairment from particulate matter emissions in any Class I area.

In 2008, ADEM submitted to EPA Alabama's first CAVR SIP, with subsequent SIPs scheduled for 2018, 2028, 2038, 2048 and 2058 to EPA. In July 2013, ADEM submitted to EPA a five-year progress review that concluded no revisions to the Alabama CAVR SIP were necessary at the time. In 2012, EPA partially approved Alabama's CAVR SIP and disapproved the parts that relied on the CAIR rule, which subsequently had been vacated after Alabama's submission of the SIP. With CAIR vacated, it is expected that EPA will support CSAPR being equivalent to BART for SO_2 and NO_x emissions for electric generating units in CSAPR-affected states. ADEM recently adopted CSAPR as equivalent for BART for SO_2 and NO_x in the Alabama CAVR SIP. However, there are remand issues regarding state CSAPR budgets (discussed in previous section) and the reliance on CSAPR being equivalent to BART is not yet fully resolved.

HAZARDOUS AIR POLLUTANTS / MERCURY

The CAAA of 1990 directed EPA to conduct the following two studies addressing hazardous air pollutants (**HAPs**) related to power plants:

- Emissions and health and environmental effects of mercury releases from all sources (**mercury study**)

- Hazards to public health resulting from utility emissions of HAPs (**utility study**)

EPA released the results of the mercury study and the utility study on December 19, 1997, and February 25, 1998, respectively. In both studies, EPA found that mercury from electric power plants is the HAP of greatest concern. Despite uncertainty in the science of mercury emissions, transport and health effects, EPA found that coal-fired power plants are the largest remaining unregulated man-made source of mercury in the United States, even though these power plants contribute about only one percent to global mercury emissions.

The Clean Air Mercury Rule (**CAMR**) was issued by EPA on March 15, 2005. The rule was issued as a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. CAMR was to be implemented in two phases – 2010 and 2018 – and provided for an emissions allowance trading market. In the first phase, the national cap on utility industry mercury emissions would be set at 38 tons (approximately a 30 percent reduction); in the second phase, the cap would be lowered to 15 tons (approximately a 70 percent reduction). The majority of reductions required for the first phase were expected to be met through co-benefits from the implementation of scrubber and SCR systems for the control of SO_2 and NO_x under CAIR. ADEM submitted Alabama's CAMR SIP in November 2006, which EPA approved in October 2007.

A number of states and environmental groups filed petitions, primarily challenging the proper source of EPA's authority to regulate mercury under the CAA. The petitioners alleged that mercury should be regulated under the "maximum achievable control technology" (**MACT**) provision of the CAA. EPA reconsidered this issue and in October 2005 decided MACT-based regulation for mercury was not "appropriate and necessary." In February 2008, the D.C. Circuit vacated CAMR and EPA's concurrent rule to "delist" electric generating units (**EGUs**) from those CAA provisions requiring application of MACT. The vacatur became effective with the issuance of the court's mandate in March 2008, thus nullifying CAMR mercury emission control obligations and monitoring requirements. EPA and the industry petitions for rehearing were denied in May 2008. Petitions for Supreme Court review were filed by industry groups and EPA in September and October 2008, respectively. EPA withdrew its petition on February 6, 2009, and the Court denied the industry petition on February 23, 2009. EPA settled that litigation and entered a consent decree to sign a proposed rule by March 16, 2011 and a final rule by November 16, 2011 to determine MACT requirements for EGUs. The consent decree deadline for a final rule was subsequently extended to December 16, 2011.

In January 2010, Alabama Power received an Information Collection Request (**ICR**) from EPA that was intended to help develop MACT emission limits for HAPs under the new rule. Alabama Power submitted its ICR response and emission test results in 2010. EPA analyzed the ICR responses from all utilities during the remainder of 2010 and proposed the Utility MACT rule on March 16, 2011. On December 16, 2011, EPA signed the final Utility MACT rule known as the Mercury and Air Toxics Standards (**MATS**) rule. The MATS rule establishes stringent emission limits for mercury, filterable particulate matter as a surrogate for non-mercury metallic HAPs, and hydrochloric acid (**HCl**) as a surrogate for acid gas HAPs. For organics, the MATS rule establishes a work practice standard requiring the implementation of a periodic tune-up and inspection program. The compliance requirements of the MATS rule are much more onerous for Alabama Power as compared to CAMR's cap-and-trade program. Compliance with the rule requires the utilization of a variety of control technologies (e.g., SCRs, scrubbers, electrostatic precipitators, baghouses, dry sorbent injection, activated carbon and/or other chemical additives) in order to meet the required limits. Compliance with the rule for existing sources would begin three years from the effective date of the final rule (April 16, 2015), unless a compliance extension is granted.

EPA received several petitions to reconsider aspects of the rule. On December 10, 2013, the D.C. Circuit heard oral arguments in the MATS case. On April 15, 2014, the court issued its opinion, denying all petitioners' challenges to the MATS rule. On July 14, 2014, several petitions were filed with the Supreme Court seeking review of the D.C. Circuit's decision. The state of Alabama participated in one such petition along with 20 other states. On June 29, 2015, the Supreme Court reversed the decision of the D.C. Circuit and found that EPA interpreted the Clean Air Act unreasonably when it deemed cost irrelevant to the decision of whether regulation of power plants under section 112 is "appropriate and necessary". While the Supreme Court directed that EPA must consider cost before deciding whether regulation of power plants is "appropriate and necessary", the court left it up to EPA to decide how to account for cost upon remand. The MATS rule remains in effect pending further action by the D.C. Circuit, but the court has asked parties to file briefs on whether the rule should continue to remain in effect while EPA addressed the cost issue.

Following the CAMR vacatur, Alabama Power continued to install and operate continuous mercury monitoring systems. These installations have enabled Alabama Power to gain useful experience with this new monitoring technology. This experience also allowed the Company to gather valuable information on actual mercury emissions in order to participate meaningfully in the MATS rulemaking as well as to plan more effectively for future mercury control compliance strategies.

In addition, Alabama Power has conducted research on mercury control technologies, such as the activated carbon injection with compact hybrid particulate collector (COHPAC) demonstration at Plant Gaston and the addition of chemical additives to aid in the control of mercury emissions. In addition, Southern Company has established the Mercury Research Center in Pensacola, Florida, the goal of which is to advance the development of technologies that reduce mercury emissions from coal-fired power boilers.

The Company has developed and continuously updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements. As part of this strategy, the Company has been implementing its compliance plan for the MATS rule, which includes reliance on existing emission control technologies (e.g., co-benefits from SCRs and scrubbers), construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, use of additives or other injection technology, use of existing or additional natural gas capability, unit retirements, and upgrades to certain transmission facilities.

CLIMATE CHANGE

Over the past several years, the U.S. Congress has considered many legislative proposals that would reduce emissions of greenhouse gases (**GHG**) and/or mandate generation of electricity from renewable energy sources. Analysis of these congressional bills has shown that they would be very costly to Alabama Power and its customers.

In 2011, Congress proposed several bills that would suspend or remove EPA's authority to regulate GHGs under the CAA. For example, the Energy Tax Prevention Act of 2011, introduced in both the House and the Senate, would have removed EPA's authority to regulate GHGs under the CAA. The EPA Stationary Source Regulations Suspension Act would have delayed stationary source permitting for two years. It is uncertain whether any such future legislation introduced in Congress will be enacted.

In April 2007, the Supreme Court ruled that EPA has authority under the current CAA to regulate GHG emissions from new motor vehicles. In response to this decision, EPA finalized an endangerment finding (a prerequisite for regulation) for GHG emissions from mobile sources in December 2009. The finding concluded that six GHGs in the atmosphere (carbon dioxide (CO_2), methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride) threaten both public health and welfare. It also found that emissions from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of these GHGs and thus to the threat of climate change. In March 2010, EPA finalized an interpretation of its stationary source rules, which specified that once GHGs are regulated under any part of the CAA, GHG emissions from new and modified sources will become "regulated pollutants" under the CAA. In April 2010, EPA (in a joint rulemaking with the National Highway Traffic Safety Administration) finalized new motor vehicle emission standards for the following GHGs: CO_2, methane, nitrous oxide and hydrofluorocarbons. These standards became effective on January 2, 2011, the first date that 2012 model-year vehicles could be sold. Accordingly, GHGs became "regulated pollutants" under the CAA on January 2, 2011, subjecting new and significantly modified stationary sources that emit certain quantities of GHGs to undergo a Best Available Control Technology (**BACT**) review for control of GHG. In an attempt to reduce the number of sources that would be required to obtain permits and the administrative burden that would ensue if Prevention of Significant Deterioration (**PSD**) permitting and Title V requirements were triggered for GHGs at the current program thresholds of 100/250 tons per year, EPA finalized a

GHG "tailoring rule" on May 13, 2010. The tailoring rule increased the major source emission thresholds for the PSD and Title V programs to 100,000 tons of CO_2 equivalent per year. The rule also increased the significance level for major modifications under the PSD program to 75,000 tons of CO_2 equivalent per year. In July 2011, EPA finalized a rule that deferred, for a period of three years, GHG permitting requirements for CO_2 emissions from biomass and other biogenic sources under the PSD and Title V programs. On July 12, 2013, the D.C. Circuit vacated this three-year deferral, but on October 15, 2013, the Supreme Court agreed to hear argument on the basic question of whether new GHGs rules for mobile sources could trigger permitting requirements for stationary sources. On June 23, 2014, the court ruled that EPA lacked the authority to require air permits from facilities based solely on their GHG emissions. It affirmed, however, EPA's authority to regulate GHG emissions from sources when those sources become subject to PSD requirements due to their emissions of conventional pollutants. The decision invalidated several elements of EPA rules that must be addressed by the EPA and the D.C. Circuit. On July 24, 2014, EPA issued guidance outlining its views on how to implement the Supreme Court's decision.

EPA also finalized its GHG Reporting Program on September 22, 2009, which requires annual reporting of GHGs. Alabama Power is fulfilling all monitoring, recordkeeping and reporting requirements necessary to comply with this rule.

On April 13, 2012, EPA published its proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units in the *Federal Register*. Had this rule been finalized as proposed, it would have effectively eliminated the development of any new coal-fired electric generating units without carbon capture and storage capability. Although this rule was not going to apply directly to existing units, EPA was planning to issue guidance to states to develop GHG standards for existing sources. However, states or courts could determine that the standard for new sources is relevant when establishing BACT for permitting modifications to existing sources.

On June 25, 2013, the President released a memorandum for the Administrator of the EPA, "Power Sector Carbon Pollution Standards", detailing a new regulatory timeline for GHG regulations. The President's memorandum directed EPA to take the following actions:

- Re-propose the GHG performance standards for new sources by September 20, 2013, and finalize these standards in a "timely fashion." The Clean Air Act requires EPA to finalize such regulations within one year after the proposal date.

- Propose GHG standards, regulations, or guidelines for modified, reconstructed, and existing sources by June 1, 2014 and finalize these requirements by June 1, 2015.

- Include in the guidelines addressing existing sources a requirement that States submit to EPA implementation plans by June 30, 2016.

In order to fulfill these Presidential directives, on January 8, 2014, EPA published in the *Federal Register* proposed GHG emission performance standards for new electric generating units. In a companion action, the EPA withdrew its proposed GHG emission performance standards for new electric generation units which had been published on April 13, 2012.

In order to fulfill the next element of the Presidential directives, on June 18, 2014, EPA published in the *Federal Register* proposed GHG emission performance standards for existing electric generating units. These regulations proposed to reduce carbon emissions from existing power plants 30 percent below 2005 levels by 2030. EPA also proposed GHG standards for modified and reconstructed electric generating units.

On August 3, 2015, EPA released pre-publication versions of two final rules that limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final rules contains specific emission standards governing CO_2 emissions from new, modified and reconstructed units. The other final rule, known as the Clean Power Plan, establishes guidelines for states to develop plans to meet EPA-mandated CO_2 emission rates for existing units. These final guidelines require state plans to meet interim CO_2 performance rates between 2022 and 2029 and final rates in 2030 and thereafter. EPA projects that the Clean Power Plan will reduce CO_2 emissions from existing power plants 32 percent below 2005 levels by 2030. EPA used three "building blocks" to establish the CO_2 performance rates: 1) improvements in plan efficiency (i.e., heat rate); 2) increased dispatch of natural gas fired units; and 3) expansion of zero-emitting renewable energy sources (e.g., wind and solar). Also on August, 3, 2015, EPA proposed a federal plan and proposed model rule that states can adopt or that would be put in place if, in response to the final guidelines, a state either does not submit a state plan or its plan is not approved by EPA.

The ultimate impact of these regulations will depend on the scope and specific requirements of the state plans and the outcome of any legal challenges, and thus cannot be determined at this time.

WATER INITIATIVES

Steam Electric Effluent Guidelines Revisions

On September 30, 2015, EPA issued a rulemaking revising the technology-based rules for steam electric plants. These new rules require dry ash handling, high levels of treatment for flue gas desulfurization wastewater, treatment of non-chemical metal cleaning wastes, and restrictions on the flow and reuse of plant water. The impacts of this rule on the Company's generating units are currently under assessment.

Impacts of MATS rules on water treatment

As part of the Company's compliance with the MATS rule, calcium bromide and brominated activated carbon will be used to capture mercury from the combustion gas. The mercury removed from the air and bromide can be transferred to the plant process water. Municipal water suppliers have to meet very low levels of halide compounds in drinking water, and there is a possibility that bromide can cause problems for them. An ADEM approved study is now underway to evaluate the levels of bromine and mercury in both plant and river water during the testing of the air control systems.

Clean Water Act (CWA) Section 316(a)

A focus on thermal issues has arisen due to EPA's renewed aggressive involvement in the permitting process. Several Alabama Power fossil plants have thermal discharge limits for the months of June through September, and Plants Barry and Gadsden have year-round thermal limits. In the past, state regulators have accepted thermal studies conducted in the 1970s based on the fact that thermal operations have not changed since the initial studies and those studies indicated no appreciable harm. However, EPA is now obligating state permitting agencies to require permittees to conduct additional studies during the five-year permit cycle to substantiate the absence of change. Alabama Power has updated thermal studies at all of its impacted plants and submitted them to ADEM along with requests for National Pollutant Discharge Elimination System (**NPDES**) permit renewals. ADEM has reviewed these studies and has indicated that the Company meets the tests for a continuation of its variances under Section 316(a). Accordingly, Alabama Power expects to continue to operate its plants in their current configuration.

CWA Section 303(d)

On July 13, 2000, a rule was issued to revise regulations under CWA Section 303(d) addressing total maximum daily loads (**TMDLs**) for certain pollutants. The TMDL rule requires the states to:

- Reduce pollutant loadings to impaired waters.
- Manage new pollutant loadings.
- Maintain a cap on the pollutant loadings that will allow the impaired water to meet water quality standards.

Economic growth and site selection of new power generation facilities in areas surrounding impaired waters may be limited as a result of TMDL development and implementation. With respect to existing facilities, evaluations of the implications of these TMDLs are underway. Regulatory agencies are continuing to propose a number of other initiatives related to water quality standards, sediments, analytical procedures, and wetlands, as well as NPDES permitting procedural issues. These proposals have the potential to impose additional restrictions on Company operations.

To date, several TMDLs have been implemented that may impact Company operations. These include the Weiss Reservoir (in December 2004), and the Logan Martin, Neely Henry, Lay and Mitchell Reservoirs in October 2008. The TMDL for Lay Reservoir includes a limit for phosphorous that caused ADEM to lower the NPDES permit for Plant Gaston. The new lower limit is not expected to impact plant operations at the current time. The proposed TMDL for mercury in a segment of the Mobile River downstream of Plant Barry is increasing Alabama Power's permit monitoring requirement and may impact the cost of treatment there. Where streams are TMDL listed for siltation (such as the Cahaba River in portions of Jefferson County), ADEM registration of nearby construction stormwater projects is more stringent and may slow or increase the cost of constructing Company facilities. There is the possibility other future TMDLs will have impacts on Company facilities.

CWA Section 316(b)

Section 316(b) requires that "the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." In 1976, EPA published a final regulation implementing this requirement. Industry groups challenged the regulation, and the U.S. Court of Appeals for the Fourth Circuit remanded on the basis of certain procedural errors made in 1977. In 1995, EPA entered into a consent decree with the Hudson Riverkeeper and a coalition of other individuals and environmental groups and committed to complete a Section 316(b) rule by August 2001.

After a series of rulemakings and court cases extending all the way to the Supreme Court, a final rule was published in the Federal Register on August 15, 2014. The rule in general gives state directors (such as ADEM) flexibility to set requirements at each power plant. Options could range from obtaining an exemption up to installing closed cycle cooling towers. One common outcome will likely be installation of "fish friendly" traveling screens and fish return troughs.

One aspect of the rule requires state permitting authorities to transmit all 316(b) NPDES permit applications to the U.S. Fish and Wildlife Service (**FWS**) and the National Marine Fisheries

Service for review prior to proposing or publishing a draft permit, and then again prior to finalization. Based on the recommendations of these agencies, EPA has pledged to object to the issuance of any permit that would endanger threatened or endangered species or their critical habitat and will prohibit state permitting agencies from issuing permits over such objections. A collection of industry and environmental organizations filed legal challenges on several aspects of the new final rule. These lawsuits were recently consolidated in the Fourth Circuit and will likely delay the enumerated compliance deadline in the current rule.

Pesticide Application Permits

On January 7, 2009, the U.S. Court of Appeals for the Sixth Circuit struck down a rule issued by EPA in 2006 regarding the application of aquatic pesticides. The court held that CWA permits are required for pesticide applications "in, over, or near" waters of the United States. For purposes of this ruling, pesticides include herbicides used in vegetation control. Alabama Power holds a permit to cover the application of hydro reservoir vector and nuisance vegetation control. Other pesticide spraying, primarily for transmission rights of way, will be performed by contract applicators that hold their own permits.

CWA Section 404

Section 404 gives the Secretary of the Army, through the Army Corps of Engineers, authority to permit the dredging from or filling of material into wetlands deemed waters of the United States. This authorization may be received through Nationwide General Permits or the issuance of Individual Permits. Construction of transmission lines, substations, power plants and environmental control facilities may require the dredging or filling in of wetlands. Significant impacts to wetlands must be mitigated in kind. A "mitigation bank" is a wetland, stream, or other aquatic resource area that has been restored, established, enhanced, or (in certain circumstances) preserved for the purpose of providing compensation for unavoidable impacts to aquatic resources permitted under Section 404. In order to accomplish this, Alabama Power is actively pursuing the creation of a wetland mitigation bank system within the state to more economically handle mitigation requirements.

From time to time, EPA and the Corps of Engineers have indicated their intent to revisit the scope of their Section 404 authority following the Supreme Court's decision in *Rapanos v. United States*, 126 S. Ct. 2208 (2006). Most recently, on August 28, 2015, EPA redefined the "waters of the United States" with a so called **Clean Water Rule**. Alabama and other states appealed this rule, and on October 9, 2015, the Sixth Circuit stayed the rule pending further decisions from the court. At this time, the Corps of Engineers has not implemented any changes on active projects underway at Alabama Power. The application of the rule is very site specific and could cause compliance issues in the future should the rule stand.

In 2011 the Corps of Engineers indicated to Alabama Power that the practice of "lop and drop", which is used to clear transmission line rights of way in wetlands, no longer will be an acceptable practice. In the view of the Corps of Engineers, the felling of large diameter trees in a wetland that are left undisturbed constitutes a fill. The practical impact of this determination will be the need to construct many more roads in wetlands in order to remove timber and to mitigate for those roads, either through the Company's own wetlands banks or through purchased credits at commercial mitigation banks.

Hydro Licensing

The Federal Energy Regulatory Commission (**FERC**) issued a new hydro license for the Coosa projects on June 20, 2013. Unfortunately, a number of provisions in the license were not properly based on the FERC licensing record or were problematic operationally. As a result, Alabama Power filed a request for a rehearing of certain provisions in the new license and a delay in implementing these provisions until the rehearing process is complete.

Among the disputed provisions are articles governing the project's CWA Section 401 water quality certification. The water quality certification issued by ADEM requires Alabama Power to meet a 4.0 parts per million (**ppm**) dissolved oxygen standard during generation. FERC misinterpreted the water quality certification to require 4 ppm dissolved oxygen at all times, instead of only during generation. On rehearing, Alabama Power has requested that FERC correct its misinterpretation of ADEM's water quality standards and water quality certification and change the water quality related license articles to reflect the appropriate state water quality standard for the hydro projects. Several other parties, including the Georgia Environmental Protection Division; the Atlanta Regional Commission; and Alabama Rivers Alliance and American Rivers have also filed for rehearing of the Coosa License. These parties have challenged several aspects of the Coosa License and have requested FERC require Alabama Power to meet an even more stringent standard of 5.0 ppm dissolved oxygen at all times.

In order to meet the existing state standard of 4.0 ppm during generation, new and upgraded turbine aeration systems are necessary at several facilities, followed by three years of monitoring and reporting at all facilities to ensure water quality requirements are met or exceeded. If FERC does not correct its misinterpretation of the Coosa water quality certification, Alabama Power could be required to meet 4.0 ppm dissolved oxygen in the tailrace of all projects at all times, including periods of non-generation. Similarly, if FERC were to grant Alabama Rivers Alliance and American Rivers' rehearing request Alabama Power could be required to meet a 5.0 ppm dissolved oxygen standard at all times. On September 30, 2015, Alabama Power filed a report with FERC responding to an additional information request (**AIR**) on alternatives for meeting a dissolved oxygen concentration of 4.0 and 5.0 ppm at all time in the tailraces of seven plants situated on the Coosa. The report explained that these expanded requirements—which had not been evaluated or justified during the licensing process—could not reasonably be met, and any attempt to do so would impose significant costs and impacts.

In addition to Section 401 certification, new licenses for the Coosa and Warrior projects include many other terms and conditions that will result in significant additional capital and operational expenditures over the life of the new licenses, which are based on proposals Alabama Power included in its application for these projects.

Alabama Rivers Alliance and American Rivers have also submitted a letter to FERC indicating their intent to sue FERC over violations of the Endangered Species Act.

On March 31, 2010, FERC issued a new 30-year license for the Lewis Smith and Bankhead developments on the Warrior River. The Smith Lake Improvement and Stakeholder Association (**SLISA**) petitioned the D.C. Circuit for review of the FERC licensing order. On September 26, 2014, the D.C. Circuit issued a decision dismissing SLISA's appeal of the Warrior River License. SLISA petitioned the court for rehearing en banc, but that petition was denied. Alabama Power is now complying with the terms and conditions of the new license.

On June 8, 2011, Alabama Power submitted the application to FERC for relicensing Martin Dam on the Tallapoosa River. The application proposed a 3-foot increase in the winter elevation of the reservoir and a conditional extension of the summer level into the fall months. FERC issued its draft Environmental Impact Statement (**EIS**) on June 6, 2013, in which the staff rejected the change to the water levels at Lake Martin. FERC conducted a public meeting in Alexander City on July 17, 2013, which was attended by over 600 members of the public, the vast majority of which supported the pool elevation changes. In addition, Alabama Power and over 800 stakeholders submitted written comments to FERC in support of the change. On April 15, 2015, FERC issued a final EIS for the Martin Project, clearing the way for a new license in the near future. In this final EIS, FERC reversed its previous position and approved the water level changes.

Municipal and County Regulations

Under pressure from EPA and environmental advocates, many local governments are passing ordinances to control construction stormwater. However, in 2014, the Alabama Legislature passed a law exempting regulated utilities from local stormwater regulation.

Endangered Species

Alabama is home to a growing list of threatened and endangered (**T&E**) species. On September 9, 2011, the FWS announced its intent to study the expansion of the critical habitat for the Gopher Tortoise from the extreme southwestern counties to what is now all of south Alabama. This species can occur on potential new transmission line rights-of-way and must be avoided or relocated. The outcome of the study by FWS remains undetermined at this time.

Alabama Power continues to address the impacts to its construction, maintenance and operations activities as T&E species are encountered. On July 8, 2013, FWS issued a recovery plan for the Alabama Sturgeon, which called for water flows in the range of previously agreed to releases. On September 19, 2013, the National Marine Fisheries Service announced a 90-day finding on a petition to list Alabama shad as threatened or endangered under the Endangered Species Act and to designate critical habitat concurrent with the listing. During the summer of 2013, Alabama Power became aware that the Indiana Bat could impact projects in north Alabama. Suitable accommodations were made with FWS, including clearing in months when the bats are not migrating in the area.

In June 2014, the Northern Long-Eared Bat was proposed for listing by the FWS and in October 2014, the Black Pine Snake was likewise proposed. The listings of both species could impact transmission line construction.

In 2015, Alabama Power began consultation with the FWS on the Rough Hornsnail found on the Coosa River. This process will proceed under the new FERC Coosa License and conditions and restrictions will become a part of the Company's Shoreline Management Plan.

TOXICS RELEASE INVENTORY

As part of the Emergency Planning and Community Right-to-Know Act (**EPCRA**), coal- and oil-fired electric power plants began in 1999 to provide EPA with data relative to specific chemicals released in the burning of fossil fuels. The report is part of a provision of the act known as the Toxics Release Inventory (**TRI**). A number of other industries have been reporting under this provision since 1987. While TRI neither sets emission limits nor establishes discharge requirements, the information in the inventory is made public. Currently, EPA and EPRI studies on power plants show that chemical emissions of TRI substances from coal and oil-fired plants are not present in the air at levels that should pose a concern to public health. The largest TRI releases from coal-fired power plants consist of acid gases such as:

- Hydrochloric acid
- Sulfuric acid
- Hydrogen fluoride

With the installation and operation of scrubbers at several plants, Alabama Power has reduced the release of these aerosols by 76 percent.

COAL COMBUSTION RESIDUALS

Fossil fuel combustion residuals, including coal combustion ash and gypsum, have traditionally been exempt from EPA hazardous waste regulations by virtue of the Bevill Amendment to the Resource Conservation and Recovery Act (**RCRA**). In December 2008, a breach occurred in an ash impoundment at a TVA facility in Kingston, Tennessee. As a result, EPA reevaluated its position on all Coal Combustion Residuals (**CCRs**).

On April 17, 2015, EPA issued a final rule concerning CCRs. EPA decided to regulate CCRs as a non-hazardous Subtitle D waste. While the impact of such regulation is not as significant as it would have been had EPA regulated CCRs as hazardous waste (Subtitle C), the stringency of the rule and its various compliance requirements appear geared toward requiring the closure of wet ash handling facilities and the adoption of fuels other than coal. EPA designed the rule to be "self-implementing," meaning it is enforced by citizen suits in federal court. States may also implement CCR programs, and EPA has stated that compliance with an EPA-approved state program should be persuasive evidence of compliance with the federal rule in court. The rule requires compliance with several components such as location standards, groundwater parameters, and structural standards, all applied to <u>existing</u> facilities.

Alabama Power currently operates a number of surface impoundments to store CCR materials. While EPA has inspected all of the Company's facilities and has determined them to be structurally sound, most of these impoundments were built long before any regulations existed. Regardless, the rule does not "grandfather" existing facilities or otherwise excuse them from meeting the stringent standards. Failure of the CCR facility to meet any of the applicable standards requires cessation of the use of the CCR facility within 6 months and the commencement of facility closure, which in turn requires either removing the CCR material or capping it and monitoring the cap and groundwater for 30 years. Any new facilities must be lined and must satisfy the location, groundwater, structural and operating standards. The rule also requires utilities to record compliance-related information and place that data on a public website.

Surface impoundments are permitted under the NPDES program to serve as the waste water treatment system for the plants. Therefore, in the event a pond was required to close, the waste water treatment system for the plant would be required to close as well, and an alternative method of treating the water would be required.

The Company expects ADEM to adopt regulations implementing EPA's standards. The Company is evaluating its options and assessing the appropriate strategy for complying with the stringent requirements of the CCR rule. Ultimately, the compliance scenario for the Company's affected generating units and their associated impoundments may encompass a course of closure, along with the requisite facility adaptions to permit closure. For example, the rule includes an option whereby a CCR impoundment can be exempted from the requirements if it can be successfully closed by April 17, 2018. Alabama Power has only one facility, Plant Gadsden, which appears eligible for this option. The Company also is evaluating other strategies, including the dry-handling of CCRs, possible off-site storage options (as compared to on-site storage options) and increasing the beneficial reuses of CCRs where possible.

In sum, the final compliance strategy for all of the Company's affected units cannot be determined at this time, although the Company continues its planning in order to be positioned to satisfy the requirements of the rule.

ESTIMATED ENVIRONMENTAL CAPITAL EXPENDITURES FOR 2016 – 2020

Including Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule)

GENERATION

Table 1 – Summary of Generation Environmental Capital Expenditures for 2016–2020

Official 2016 Capital Budget ($000)

	2016	2017	2018	2019	2020
Total NOx Projects (SCR's)	2,904	14,802	21,034	17,262	8,614
Total SO2 Projects (Scrubbers)	6,795	3,467	4,197	10,834	12,246
Total CCR-WATER	48,095	62,575	35,081	9,844	-
Total CCR-LAND	47,618	105,175	154,944	73,390	12,367
Total Effluent Guidelines/NPDES	75	-	-	-	-
Total MATS	86,696	-	-	5,295	4,530
Total Particulate Matter (PM)	65,172	28,839	5,239	2,604	1,705
Total Hydro Aeration and Minimum Flow Projects	5,900	5,400	500	-	-
Total CEMS Projects	613	1,712	1,522	3,850	2,988
Total Sewage Treatment	48	100	-	-	-
Total Cooling Tower/Intake Structure	12,794	550	980	3,750	2,900
Total Environmental Compliance Projects - Total	276,710	222,620	223,497	126,829	45,350
Total Air Projects	162,180	48,820	31,992	39,845	30,083
Total Land Projects	47,618	105,175	154,944	73,390	12,367
Total Water Projects	66,912	68,625	36,561	13,594	2,900
Total Environmental Compliance Projects	276,710	222,620	223,497	126,829	45,350

Total CCR Expenditures (including Cost of Removal)

	2016	2017	2018	2019	2020
Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	95,713	167,750	190,025	83,234	12,367
Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	7,632	7,864	47,563	73,389	125,606
Total CCR	103,345	175,614	237,588	156,623	137,973

Table 2 – Summary by Plant of Environmental Capital Expenditures for 2016–2020

Official 2016 Capital Budget ($000)

	2016	2017	2018	2019	2020
Total Barry	25,845	71,286	65,298	39,367	4,997
Barry NOx Projects (SCRs)	-	2,200	-	2,200	-
Barry SO2 Projects (Scrubbers)	-	875	75	1,780	-
Barry CCR-WATER	8,249	12,110	6,278	2,458	-
Barry CCR-LAND	2,061	27,601	58,945	30,479	4,697
Barry MATS	6,985	-	-	-	-
Barry Particulate Matter (PM)	8,550	28,500	-	1,950	300
Barry CEMS Projects	-	-	-	500	-
Total Gadsden	9,216	-	-	-	-
Gadsden CCR-WATER	9,216	-	-	-	-
Total Gaston	83,246	57,000	54,016	4,690	14,650
Gaston NOx Projects (SCRs)	-	500	2,300	500	3,100
Gaston SO2 Projects (Scrubbers)	4,000	200	1,000	440	5,950
Gaston CCR-WATER	5,000	15,000	15,000	2,000	-
Gaston CCR-LAND	27,912	41,000	34,916	1,000	-
Gaston MATS	45,134	-	-	-	3,000
Gaston Particulate Matter (PM)	-	-	-	-	-
Gaston CEMS Projects	400	-	-	-	-
Gaston Cooling Tower/Intake Structure	800	300	800	750	2,600
Total Gorgas	37,797	42,682	46,673	45,572	3,030
Gorgas NOx Projects (SCRs)	-	3,100	6,020	6,150	-
Gorgas SO2 Projects (Scrubbers)	-	2,300	-	7,895	1,500
Gorgas CCR-WATER	8,913	13,187	6,758	2,637	-
Gorgas CCR-LAND	14,938	23,595	33,875	23,595	-
Gorgas MATS	13,946	-	-	5,295	1,530
Gorgas Particulate Matter (PM)	-	-	-	-	-
Gorgas CEMS Projects	-	400	20	-	-
Gorgas Sewage Treatment	-	100	-	-	-
Total Greene Co	25,178	8,530	-	-	600
Greene Co CCR-WATER	7,424	8,530	-	-	-
Greene Co MATS	17,754	-	-	-	-
Greene Co CEMS Projects	-	-	-	-	600
Total Miller	88,363	37,222	53,180	32,250	21,773
Miller NOx Projects (SCRs)	2,904	8,752	9,464	7,212	5,514
Miller SO2 Projects (Scrubbers)	2,795	92	3,122	719	4,796
Miller CCR-WATER	9,293	13,748	7,045	2,749	-
Miller CCR-LAND	2,707	12,979	27,208	18,316	7,670
Miller MATS	2,877	-	-	-	-
Miller Particulate Matter (PM)	56,622	339	5,239	654	1,405
Miller CEMS Projects	103	1,312	1,102	2,600	2,388
Miller Sewage Treatment	48	-	-	-	-
Miller Cooling Tower/Intake Structure	11,014	-	-	-	-
Total Other	1,165	500	3,830	4,950	300
Other NOx Projects (SCRs)	-	250	3,250	1,200	-
Other Effluent Guidelines/NPDES	75	-	-	-	-
Other CEMS Projects	110	-	400	750	-
Other Cooling Tower/Intake Structure	980	250	180	3,000	300
Total Hydro	5,900	5,400	500	-	-

Table 2 - Summary by Plant of Environmental Capital Expenditures for 2016-2020 (continued)

Total CCR Expenditures (including Cost of Removal)

	2016	2017	2018	2019	2020
Barry Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	10,310	39,711	65,223	32,937	4,697
Barry Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	-	-	14,831	22,884	39,167
Barry Total CCR	10,310	39,711	80,054	55,821	43,864
Gadsden Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	9,216	-	-	-	-
Gadsden Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	7,632	7,864	-	-	-
Gadsden Total CCR	16,848	7,864	-	-	-
Gaston Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	32,912	56,000	49,916	3,000	-
Gaston Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	-	-	3,920	6,048	10,351
Gaston Total CCR	32,912	56,000	53,836	9,048	10,351
Gorgas Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	23,851	36,782	40,633	26,232	-
Gorgas Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	-	-	13,230	20,414	34,939
Gorgas Total CCR	23,851	36,782	53,863	46,646	34,939
Greene County Co Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	7,424	8,530	-	-	-
Greene County Co Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	-	-	7,691	11,867	20,310
Greene County Co CCR Total	7,424	8,530	7,691	11,867	20,310
Miller Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	12,000	26,727	34,253	21,065	7,670
Miller Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	-	-	7,891	12,176	20,839
Miller CCR Total	12,000	26,727	42,144	33,241	28,509

Table 3(a) – Plant Barry Environmental Capital Expenditures for 2016–2020

Official 2016 Capital Budget ($000)

	DESCRIPTION	PE	2016	2017	2018	2019	2020
Barry	Unit 4 - Precip Fly Ash Carrier Line Replacement	028305	-	1,500	-	-	-
Barry	Unit 4 - Replace 4A Hydrovacator Tank & Ejector	029303	-	-	-	-	150
Barry	Unit 4 - Replace 4C Hydrovacator Tank & Ejector	029304	-	-	-	-	150
Barry	Unit 4 - Precipitator Replacement Project	034501	3,000	12,000	-	-	-
Barry	Unit 5 - Precipitator Ductwork	034503	-	-	-	-	-
Barry	Unit 4 - Dry Sorbent Injection	034916	447	-	-	-	-
Barry	Unit 4 - Activated Carbon Injection	034917	287	-	-	-	-
Barry	Unit 4 - Dry Bottom Ash	0349BA	165	3,972	8,440	3,972	-
Barry	Unit 4 - Dry Fly Ash	0349FA	143	3,467	7,418	3,407	-
Barry	Unit 4 - CCR Waste Water Management	0349CR	3,180	4,597	2,389	930	-
Barry	Unit 5 - Replace Precipitator Rappers (A&B)	035403	5,000	15,000	-	-	-
Barry	Unit 5 - Precipitator Hoists	035406	-	-	-	-	-
Barry	Unit 5 - Sulfur Burner Catalyst	039105	-	-	-	150	-
Barry	Unit 5 - SCR Elevator	039519	-	-	-	-	-
Barry	Unit 5 - Scrubber Elevator	039520	-	-	-	-	-
Barry	Unit 5 - SCR Catalyst Replacement	039905	-	2,200	-	2,200	-
Barry	Unit 5 - Scrubber Mist Eliminator	039906	-	-	-	-	-
Barry	Unit 5 - Replace CEMS	039910	-	-	-	500	-
Barry	Unit 5 - Additional Gypsum Pond Cell Construction	039920	-	-	-	-	-
Barry	Unit 5 - Scrubber Seal Air System	039921	-	-	-	200	-
Barry	Unit 5 - JBR Gearbox Replacement	039922	-	225	-	-	-
Barry	Unit 5 - Air Compressor Replacement (Scrubber)	039923	-	-	75	-	-
Barry	Unit 5 - JBR Sump Pump Discharge Line	039924	-	-	-	80	-
Barry	Unit 5 - Gypsum Pile Dust Suppression	039925	-	-	300	-	-
Barry	Unit 5 - DCS System Replacement (scrubber)	039926	-	-	-	1,500	-
Barry	Unit 5 - Scrubber Teflon Expansion Joints Replacement	039929	-	400	-	-	-
Barry	Unit 5 - Scrubber JBR Alignment Grid Replacement	039933	-	-	-	-	-
Barry	Unit 5 - Scrubber Viton Expansion Joint Replacement	039934	-	-	-	-	-
Barry	Unit 5 - Sparger System Piping	039935	-	250	-	-	-
Barry	Unit 5 - Gas Cooling Duct Replacement	039938	-	-	-	-	-
Barry	Unit 5 - Mercury Re-Emission Control System	039940	6,251	-	-	-	-
Barry	Unit 5 - Dry Bottom Ash	0399BA	331	7,944	16,880	7,944	-
Barry	Unit 5 - Dry Fly Ash	0399FA	439	10,645	22,776	10,459	-
Barry	Unit 5 - CCR Waste Water Management	0399CR	5,069	7,513	3,889	1,528	-
Barry	Unit 5 - Replace 5 Hydrovacator Tank & Ejector	040601	-	-	-	150	-
Barry	Common - Landfill Phase 1	0474LF	983	1,573	3,131	4,697	4,697
Barry	Common - Dust Suppression - 4&5 Bunker Floor	049802	550	-	-	1,650	-
	Total Barry		25,845	71,286	65,298	39,367	4,997
	Barry Nox Projects (SCRs)		-	2,200	-	2,200	-
	Barry SO2 Projects (Scrubbers)		-	875	75	1,780	-
	Barry CCR-WATER		8,249	12,110	6,278	2,458	-
	Barry CCR-LAND		2,061	27,601	58,945	30,479	4,697
	Barry MATS		6,985	-	-	-	-
	Barry Particulate Matter (PM)		8,550	28,500	-	1,950	300
	Barry CEMS Projects		-	-	-	500	-

Total Plant Barry CCR Expenditures (including Cost of Removal)

	DESCRIPTION	2016	2017	2018	2019	2020
Barry	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	10,310	39,711	65,223	32,937	4,697
Barry	Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	0	0	14,831	22,884	39,167
	Barry Total CCR	10,310	39,711	80,054	55,821	43,864

Table 3(b) – Plant Gadsden Environmental Capital Expenditures for 2016–2020

Official 2016 Capital Budget ($000)

	DESCRIPTION	PE	2016	2017	2018	2019	2020
Gadsden	Common - CCR Waste Water Management	0646LV	9,216	-	-	-	-
	Total Gadsden		9,216	-	-	-	-
	Gadsden CCR-WATER		9,216	-	-	-	-

Total Plant Gadsden CCR Expenditures (including Cost of Removal)

	DESCRIPTION	2016	2017	2018	2019	2020
Gadsden	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	9,216	0	0	0	0
Gadsden	Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	7,632	7,864	0	0	0
	Gadsden Total CCR	16,848	7,864	0	0	0

Table 3(c) – Plant Gaston Environmental Capital Expenditures for 2016–2020

Official 2016 Capital Budget ($000)

	DESCRIPTION	PE	2016	2017	2018	2019	2020
Gaston	Unit 5 - Cooling Tower Fill (one cell per year)	066501	800	-	800	-	900
Gaston	Unit 5 - Cooling Tower Louvers	069702	-	-	-	-	200
Gaston	Unit 5 - Catalyst Replacement	069904	-	500	2,300	500	2,300
Gaston	Unit 5 - Scrubber Sparger Tubes	069910	-	-	-	-	2,000
Gaston	Unit 5 - Scrubber Agitator	069911	-	-	500	-	500
Gaston	Unit 5 - Scrubber Agitator Gearbox	069912	250	-	300	140	350
Gaston	Unit 5 - Scrubber DCS UPS	069918	-	-	-	-	1,000
Gaston	Unit 5 - Scrubber Valves	069919	-	-	200	-	300
Gaston	Unit 5 - Activated Carbon Injection	069921	550	-	-	-	-
Gaston	Unit 5 - Baghouse - SAMC	069922	1,050	-	-	-	-
Gaston	Unit 5 - Scrubber Motors	069924	-	100	-	200	100
Gaston	Unit 5 - Baghouse	069925	43,534	-	-	-	-
Gaston	Unit 5 - Scrubber Limestone Blowers	069932	-	-	-	-	-
Gaston	Unit 5 - Scrubber Oxidation Air Blower	069933	-	-	-	-	-
Gaston	Unit 5 - Scrubber Gas Cooling Pump	069934	-	-	-	-	-
Gaston	Unit 5 - Scrubber Gas Cooling Pump Strainers	069935	-	-	-	-	750
Gaston	Unit 5 - Scrubber Sump Pump	069936	-	100	-	100	100
Gaston	Unit 5 - Scrubber Nozzles	069937	750	-	-	-	850
Gaston	Unit 5 - Scrubber Mist Eliminator	069939	-	-	-	-	-
Gaston	Unit 5 - Scrubber Gas Expansion Joints	069940	2,100	-	-	-	-
Gaston	Unit 5 - SCR Ammonia Piping	069943	-	-	-	-	800
Gaston	Unit 5 - Baghouse Bags	069944	-	-	-	-	3,000
Gaston	Unit 5 - Scrubber Air Compressor	069945	-	-	-	-	-
Gaston	Unit 5 - SCR Air Compressors	069947	-	-	-	-	-
Gaston	Unit 5 - SCR Air Dryer	069948	-	-	-	-	-
Gaston	Unit 5 - Scrubber Gas Cooling Pump Motors	069949	-	-	-	-	-
Gaston	Unit 5 - Scrubber Oxidation Air Motors	069950	-	-	-	-	-
Gaston	Unit 5 - CCR Storage Facility	069951	-	-	-	-	-
Gaston	Unit 5 - Scrubber Prequench Lances	069952	900	-	-	-	-
Gaston	Unit 5 - Scrubber Air Dryer	069953	-	-	-	-	-
Gaston	Unit 5 - Cooling Tower Motor Control Center	070303	-	-	-	750	1,500
Gaston	Unit 5 - Replace Dry Ash Lines	070603	-	-	-	-	-
Gaston	Unit 5 - Replace CEMS	070901	400	-	-	-	-
Gaston	Unit 5 - CW PUMP MOTOR	074903	-	-	-	-	-
Gaston	Unit 5 - Gypsum Storage Pond Expansion	075501	16,912	15,000	14,000	-	-
Gaston	Unit 5 - Gypsum Ponds (Small Additions)	075502	-	-	-	-	-
Gaston	Unit 5 - Hvac Cooling Tower Breaker Building	079405	-	300	-	-	-
Gaston	Unit 5 - Dry Bottom Ash	0810BA	3,000	12,000	18,000	1,000	-
Gaston	Unit 5 - Dry Fly Ash	0810FA	8,000	14,000	2,916	-	-
Gaston	Common - CCR Waste Water Management	0835CR	5,000	15,000	15,000	2,000	-
	Total Gaston		83,246	57,000	54,016	4,690	14,650
	Gaston NOx Projects (SCRs)		-	500	2,300	500	3,100
	Gaston SO2 Projects (Scrubbers)		4,000	200	1,000	440	5,950
	Gaston CCR-WATER		5,000	15,000	15,000	2,000	-
	Gaston CCR-LAND		27,912	41,000	34,916	1,000	-
	Gaston MATS		45,134	-	-	-	3,000
	Gaston Particulate Matter (PM)		-	-	-	-	-
	Gaston CEMS Projects		400	-	-	-	-
	Gaston Cooling Tower/Intake Structure		800	300	800	750	2,600

Total Plant Gaston CCR Expenditures (including Cost of Removal)

	DESCRIPTION	2016	2017	2018	2019	2020
Gaston	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	32,912	56,000	49,916	3,000	0
Gaston	Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	0	0	3,920	6,048	10,351
	Gaston Total CCR	32,912	56,000	53,836	9,048	10,351

Table 3(d) – Plant Gorgas Environmental Capital Expenditures for 2016–2020

Official 2016 Capital Budget ($000)

	DESCRIPTION	PE	2016	2017	2018	2019	2020
Gorgas	Unit 8 - CEMS	096902		100	-		
Gorgas	Unit 9 - CEMS	101402	-	100	-		
Gorgas	Unit 10 - Install Title 1 Clean Air SCR Catalyst	108903	-	3,000	-	6,000	-
Gorgas	Unit 10 - CEMS	108904	-	200	-		
Gorgas	Unit 10 - SCR Inlet Duct Additions	108905	-	100	6,000	50	-
Gorgas	Unit 10 - Ammonia Forwarding Pumps	108916	-	-	-		-
Gorgas	Unit 10 - Ammonia Unloading Compressors	108917	-	-	-	100	-
Gorgas	Unit 10 - Ammonia Vaporizers	108918	-	-	-		-
Gorgas	Unit 10 - SCR Soot blower	108921	-	-	-		-
Gorgas	Unit 10 - FGAS NOX Monitors	108922	-	-	20		-
Gorgas	Unit 10 - Replace Flue Gas Conditioning System	109001	-	-	-		-
Gorgas	Common - Ash Pumping Station 600 V and 4160 V MCC	111307	100	-	-		-
Gorgas	Common - Gypsum Storage Addition	111716	-	-	-		-
Gorgas	Common - Replace Scrubber Stack Mercury Monitor Umbilical's	111718	-		-	100	
Gorgas	Common - Baghouse	111725	13,946	-	-	-	-
Gorgas	Common - Scrubber Limestone Feeders	111727	-	1,500	-	-	-
Gorgas	Common - Scrubber Absorber Sump Pump	111732	-	-	-	200	-
Gorgas	Common - Scrubber Booster Fans	111733	-	-	-	1,000	-
Gorgas	Common - Scrubber Limestone Sump Pumps	111734	-	-	-	500	-
Gorgas	Common - Scrubber Recycle Pumps/Motors	111735	-	500	-	500	
Gorgas	Common - Scrubber ARS Gearboxes	111736	-	-	-	900	-
Gorgas	Common - Scrubber Duct Expansion Joints	111737	-	-	-	1,500	-
Gorgas	Common - Scrubber Inlet Joint	111738	-	-	-	2,500	-
Gorgas	Gypsum Dry Stacking Transfer Pumps	111744	-	-	-		-
Gorgas	Common - Scrubber Oxidation Air Blower Motor	111745	-	-	-	150	-
Gorgas	Common - Scrubber Makeup & Gypsum Water Pump Motors	111746	-	-	-	220	-
Gorgas	Common - Scrubber Controls Retrofit	111747	-	-	-	-	1,500
Gorgas	Common - 5000 Baghouse Saxing Bag Replacement	111757	-	-	-	2,200	-
Gorgas	Common - 5100 Baghouse Saxing Bag Replacement	111758	-	-	-	2,200	-
Gorgas	Common - Bahouse Pub Mills Replacement	111759	-	-	-	-	-
Gorgas	Common - Baghouse Air Compressors	111760	-	-	-	-	-
Gorgas	Common - Baghouse Air Dryer	111761	-	-	-	-	200
Gorgas	Common - SAMC Blowers	111762	-	-	-	140	-
Gorgas	Common - SAMC Air Compressors	111763	-	-	-	140	-
Gorgas	Common - SAMC Rotary Feeders	111764	-	-	-	-	95
Gorgas	Common - SAMC Air Dryers	111765	-	-	-	120	-
Gorgas	Common - ACI Rotary Feeders	111766	-	-	-	-	110
Gorgas	Common - ACI Blowers	111767	-	-	-	-	150
Gorgas	Common - Byproduct Silo Filter Collector Bag Replacement	111768	-	-	-	175	-
Gorgas	Common - Byproduct Silo Fluidizing Media Replacement	111769	-	-	-	320	-
Gorgas	Common - Byproduct Fluidizing Blower Replacement	111770	-	-	-	-	205
Gorgas	Common - Byproduct System Vacuum Blowers	111771	-	-	-	-	260
Gorgas	Common - Byproduct System Air Compressors	111772	-	-	-	-	185
Gorgas	Common - Byproduct Air Locks	111773	-	-	-	-	200
Gorgas	Common - Byproduct System Air Dryers	111775	-	-	-	-	125
Gorgas	Common - U8 & U9 Data Loggers - CEMS	111776	-	-	20	-	-
Gorgas	Common - Neutralized Waste Water Pumps	111777	-	100	-	-	-
Gorgas	Dry Bottom Ash	1117BA	381	9,138	19,418	9,138	-
Gorgas	Dry Fly Ash	1117FA	14,457	14,457	14,457	14,457	-
Gorgas	CCR Waste Water Management	1117CR	8,913	13,187	6,758	2,637	-
Gorgas	Scrubber Station Service Batteries	113525	-	300	-	325	-
	Total Gorgas		37,797	42,682	46,673	45,572	3,030
	Gorgas NOx Projects (SCRs)		-	3,100	6,020	6,150	-
	Gorgas SO2 Projects (Scrubbers)		-	2,300	-	7,895	1,500
	Gorgas CCR-WATER		8,913	13,187	6,758	2,637	-
	Gorgas CCR-LAND		14,938	23,595	33,875	23,595	-
	Gorgas MATS		13,946	-	-	5,295	1,530
	Gorgas Particulate Matter (PM)		-	-	-	-	-
	Gorgas CEMS Projects		-	400	20	-	-
	Gorgas Sewage Treatment		-	100	-	-	-

Total Plant Gorgas CCR Expenditures (including Cost of Removal)

		2016	2017	2018	2019	2020
Gorgas	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	23,851	36,782	40,633	26,232	0
Gorgas	Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	0	0	13,230	20,414	34,939
	Gorgas Total CCR	23,851	36,782	53,863	46,646	34,939

Table 3(e) – Plant Greene Co. Environmental Capital Expenditures for 2016–2020

Official 2016 Capital Budget ($000)

	DESCRIPTION	PE	2016	2017	2018	2019	2020
Greene	Unit 1 - Gas Capability	119919	8,920	-	-	-	-
Greene	Unit 2 - Gas Capability	124919	7,370	-	-	-	-
Greene	Common - Gas Capability	129906	1,464	-	-	-	-
Greene	Common - CEMS	129910		-	-	-	600
Greene	Common - CCR Waste Water Management	1299CR	7,424	8,530	-	-	-
	Total Greene Co		25,178	8,530	-	-	600
	Greene Co CCR-WATER		7,424	8,530	-	-	-
	Greene Co MATS		17,754	-	-	-	-
	Greene Co CEMS Projects			-	-	-	600

Total Plant Greene Co. CCR Expenditures (including Cost of Removal)

	DESCRIPTION	2016	2017	2018	2019	2020
Greene	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	7,424	8,530	0	0	0
Greene	Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	0	0	7,691	11,867	20,310
	Greene Total CCR	7,424	8,530	7,691	11,867	20,310

Table 3(f) – Plant Miller Environmental Capital Expenditures for 2016–2020

Official 2016 Capital Budget ($000)

	DESCRIPTION	PE	2016	2017	2018	2019	2020
Miller	Unit 1 - Install Clean Air Catalyst	131403	92	1,056	1,607	1,056	1,607
Miller	Unit 1 - Booster Fan A Blade Replacement	131410	-	-	-	-	-
Miller	Unit 1 - Booster Fan B Blade Replacement	131411	-	-	-	-	-
Miller	Unit 1 - Absorber Inlet Expansion Joint	131417	-	46	1,561	-	-
Miller	Unit 1 - Booster Fan Hub Replacement (A&B)	131420	918	-	-	-	-
Miller	Unit 1 - Mercury Re-Emission Control System	131422	459	-	-	-	-
Miller	Unit 1 - Outlet Hood Expansion Joint	131425	-	-	1,240	-	-
Miller	Unit 1 - Replace SCR Expansion Joints	131426	-	-	735	-	-
Miller	Unit 1 - Replace SCR FGAS Shelter	131427	-	-	-	-	-
Miller	Unit 1 - Replace Precipitator Outlet Damper	131428	-	-	-	-	-
Miller	Unit 1 - Dust Valve Replacement	133204	293	-	-	-	-
Miller	Unit 1 - Replace Economizer Line from Hoppers to Air Separator	135901	-	-	-	-	-
Miller	Unit 1 - Replace Economizer Discharge Line from Air Separator Tank	135902	-	-	-	-	-
Miller	Unit 1 - Replace Dry ash Transfer Vessel	136502	-	92	32	-	-
Miller	Unit 2 - Replace Dry Ash Transfer Vessel	139802	-	-	124	-	-
Miller	Unit 2 - Outlet Hood Expansion Joint	141807	-	-	1,240	-	-
Miller	Unit 2 - Booster Fan B Blade Replacement	141811	-	-	-	-	-
Miller	Unit 2 - Replace SCR Expansion Joints	141813	-	-	735	-	-
Miller	Unit 2 - Absorber Inlet Expansion Joint	141817	-	46	1,561	-	-
Miller	Unit 2 - Booster Fan Hub Replacement (A&B)	141819	918	-	-	-	-
Miller	Unit 2 - Mercury Re-Emission Control System	141820	918	-	-	-	-
Miller	Unit 2 - Replace SCR FGAS Shelter	141823	-	-	-	-	-
Miller	Unit 2 - Economizer Ash to Hydrobins	142001	-	-	-	-	-
Miller	Unit 2 - Dust Valve Replacement	142004	101	-	-	-	-
Miller	Unit 2 - Replace Precipitator Internals	143301	56,022	-	-	-	-
Miller	Unit 2 - Replace Precipitator Outlet Damper	143303	-	-	-	-	-
Miller	Unit 2 - Replace Economizer Line from Hoppers	143602	-	-	-	-	-
Miller	Unit 2 - Install SCR Catalyst	143701	92	1,056	1,607	1,056	1,607
Miller	Units 1 & 2 - Cooling Twr Fill	145101	10,470	-	-	-	-
Miller	Units 1 & 2 - Cooling TwrChemical Tank Pump	145106	-	-	-	-	-
Miller	Units 1 & 2 - Cooling Twr Sodium Hypochlorite System	145108	230	-	-	-	-
Miller	Units 1 & 2 - Bypass Stack CEMS Shelter	145203	-	-	1,102	-	-
Miller	Units 1 & 2 - CEMS Dataloggers	145204	103	-	-	-	-
Miller	Units 1 & 2 - FGD Inlet CEMS Shelter	145205	-	-	-	-	735
Miller	Units 1 & 2 - FGD Stack CEMS Shelter	145206	-	-	-	-	1,653
Miller	Units 1 & 2 - Cooling Twr Battery System	145902	64	-	-	-	-
Miller	Units 1-4 - Gypsum Dewatering System Main Filter Belt A Replacement	150316	-	-	-	120	-
Miller	Units 1-4 - Gypsum Dewatering System Main Filter Belt B Replacement	150317	-	-	-	120	-
Miller	Units 1-4 - Install Scrubber Waste WTP	150336	-	-	-	719	4,796
Miller	Units 1-4 - Replace Cooling Tower Acid Tanks	150337	-	-	-	-	-
Miller	Units 1-4 - Replace Gypsum Dewatering Battery	150341	288	-	-	-	-
Miller	Units 1-4 - Install FGD Waste Water Piping & Valves	150342	959	-	-	-	-
[redacted]							
Miller	Units 1-4 - Dry Bottom Ash	1503BA	434	10,405	22,113	10,406	-
Miller	Units 1-4 - Landfill Phase 1	1503LF	1,985	2,574	5,095	7,670	7,670
Miller	Units 1-4 - CCR Waste Water Management	1503CR	9,293	13,748	7,045	2,749	-
Miller	Units 1-4 - Replace Ash Booster Station Switchgear	150404	-	-	-	-	719
Miller	Units 1-4 - A Fly Ash Booster Pump Discharge Valve	152902	-	-	-	-	-
Miller	Units 1-4 - B Fly Ash Booster Pump Discharge Valve	152903	-	-	65	-	-
Miller	Units 1-4 - C Fly Ash Booster Pump Discharge Valve	152904	-	-	-	-	-
Miller	Units 1-4 - Replace Fly Ash Booster Pump Controls	154102	-	-	-	-	-
Miller	Units 1-4 - Hydrobin VALVES AND GATES	154202	144	144	-	-	144
Miller	Units 1-4 - Replace Hydrobin Elevator	154206	-	-	-	-	480
Miller	Units 1-4 - Replace Dry Ash Line from Units 1-4 to Silos	154305	-	-	-	576	-
Miller	Units 1-4 - Replace Ash Silo Air Operated Valves	154310	38	19	38	19	38
Miller	Units 1-4 - Replace Ash Silo Scavanger Air Fans	154311	24	24	24	24	24
Miller	Units 1-4 - Install Ash Silo Pug Mill (Conditioner)	154312	-	-	4,796	-	-
Miller	Unit 3 - Replace Economizer Line from Hoppers to Air Sep.	155802	-	-	-	-	-
Miller	Unit 3 - Replace Economizer Ash Air Separator Tank	155804	-	60	-	-	-
Miller	Unit 3 - Booster Fan A Blade Replacement	157516	-	-	-	-	-
Miller	Unit 3 - Booster Fan B Blade Replacement	157517	-	-	-	-	-
Miller	Unit 3 - Booster Fan Hub Replacement (A&B)	157521	-	-	-	-	-
Miller	Unit 3 - Mercury Re-Emission Control System	157524	500	-	-	-	-
Miller	Unit 3 - Outlet Hood Expansion Joint	157526	-	1,350	-	-	-
Miller	Unit 3 - Replace Ammonia Forwarding Pumps	157527	100	-	-	-	-
Miller	Unit 3 - Replace SCR Expansion Joints	157528	-	-	-	800	-
Miller	Unit 3 - Replace SCR FGAS Shelter	157529	-	-	-	-	-
Miller	Unit 3 - Precipitators-Install inlet sonic horns	158101	-	-	-	-	-
Miller	Unit 3 - Replace SCR Catalyst	159501	1,150	1,750	1,150	1,750	1,150
Miller	Unit 3 - PLC to DCS Conversion for Vaporization Skid Controls	161001	110	220	-	-	-
Miller	Unit 4 - Replace SCR Catalyst	164503	1,150	1,750	1,150	1,750	1,150

Miller	Unit 4 - Booster Fan B blade replacement	164517	-	-	-	-	-
Miller	Unit 4 - Booster Fan Hub Replacement (A&B)	164522	-	-	-	-	-
Miller	Unit 4 - Mercury Re-Emission Control System	164524	1,000	-	-	-	-
Miller	Unit 4 - Outlet Hood Expansion Joint	164526	-	1,350	-	-	-
Miller	Unit 4 - Replace Ammonia Forwarding Pumps	164527	100	-	-	-	-
Miller	Unit 4 - Replace SCR Expansion Joints	164528	-	-	-	800	-
Miller	Unit 4 - Replace SCR FGAS Shelter	164529	-	-	-	-	-
Miller	Unit 4 - Replace Economizer Line from Hoppers to Air Separator	164802	-	-	-	-	-
Miller	Unit 4 - Replace Economizer Ash Air Separator Tank	164805	-	-	60	-	-
Miller	Unit 4 - Install Sonic Horns on Precipitator	165401	-	-	-	-	-
Miller	Unit 4 - PLC to DCS Conversion for Vaporizer Skid Controls	168001	110	220	-	-	-
Miller	Units 3 & 4 - Bypass Stack CEMS Shelter	170203	-	1,200	-	-	-
Miller	Units 3 & 4 - Replace CEMS Dataloggers	170204	-	112	-	-	-
Miller	Units 3 & 4 - FGD Inlet CEMS Shelter	170205	-	-	-	800	-
Miller	Units 3 & 4 - FGD Stack CEMS Shelter	170206	-	-	-	1,800	-
Miller	Units 3 & 4 - Replace Cooling Tower Chemical Tank/Pump	170604	-	-	-	-	-
Miller	Units 3 & 4 - Install Cooling Twr Sodium Hypochlorite System	170605	250	-	-	-	-
Miller	Units 3 & 4 - Dry Ash Transfer Vessel	174903	-	-	100	35	-
	Total Miller		88,363	37,222	53,180	32,250	21,773
	Miller NOx Projects (SCRs)		2,904	8,752	9,464	7,212	5,514
	Miller SO2 Projects (Scrubbers)		2,795	92	3,122	719	4,796
	Miller CCR-WATER		9,293	13,748	7,045	2,749	-
	Miller CCR-LAND		2,707	12,979	27,208	18,316	7,670
	Miller MATS		2,877	-	-	-	-
	Miller Particulate Matter (PM)		56,622	339	5,239	654	1,405
	Miller CEMS Projects		103	1,312	1,102	2,600	2,388
	Miller Sewage Treatment		48	-	-	-	-
	Miller Cooling Tower/Intake Structure		11,014	-	-	-	-

Total Plant Miller CCR Expenditures (including Cost of Removal)

		2016	2017	2018	2019	2020
Miller	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	12,000	26,727	34,253	21,065	7,670
Miller	Cost of Removal (Cost for Closure in Place Pursuant to CCR Rule) (Not included in above amounts)	0	0	7,891	12,176	20,839
	Miller Total CCR	12,000	26,727	42,144	33,241	28,509

Table 4 – Other Generation Environmental Capital Expenditures for 2016–2020

Official 2016 Capital Budget ($000)

	DESCRIPTION	PE	2016	2017	2018	2019	2020
Wash	HRSG CEMS	181504	-	-	400	-	-
Wash	Package Boiler 201 CEMS	182307	110	-	-	130	-
Wash	Cooling Tower Media Replacement	182401	-	250	-	-	300
Wash	Replace Waste Water Cooling Tower	182403	-	-	-	-	-
Wash	Cooling Tower Drift Eliminator Media Replacement	182406	-	-	-	-	-
Wash	Side Stream Filtration System for Cooling Tower	182407	200	-	-	-	-
Wash	Side Stream Filtration System for Cooling Tower	182407	-	-	-	-	-
Theodore	Replace SCR Catalyst	182901	-	250	1,250	-	-
Theodore	Cooling Tower Media Replacement	183208	-	-	-	-	-
Theodore	HRSG & PB CEMS Replacement	183210	-	-	-	-	-
Theodore	Cooling Tower Fans	183218	-	-	80	-	-
Theodore	Cooling Tower Drift Eliminator Media	183223	-	-	100	-	-
Theodore	Neutralization Tank Pumps (Waste water)	183224	75	-	-	-	-
Barry CC	Unit 6 - Replace SCR Catalyst	186801	-	-	1,000	600	-
Barry CC	Unit 7 - Replace SCR Catalyst	186802	-	-	1,000	600	-
Barry CC	Unit 6 - Replace CEMS Monitoring Equip	187109	-	-	-	310	-
Barry CC	Unit 7 - Replace CEMS Monitoring Equip	187110	-	-	-	310	-
Barry CC	Unit 6 - Cooling Tower Media Replacement	187135	-	-	-	1,500	-
Barry CC	Unit 7 - Cooling Tower Media Replacement	187136	-	-	-	1,500	-
Barry CC	Unit 6 - Cooling Tower Fans	187139	250	-	-	-	-
Barry CC	Unit 7 - Cooling Tower Fans	187140	250	-	-	-	-
Barry CC	Unit 6 - Cooling Tower Drift Eliminator Media Replacement	187146	-	-	-	-	-
Barry CC	Unit 7 - Cooling Tower Drift Eliminator Media Replacement	187147	-	-	-	-	-
Barry CC	Unit 6 - Cooling Tower Transformer Replacement	187171	180	-	-	-	-
Barry CC	Unit 7 - Cooling Tower Transformer Replacement	187172	100	-	-	-	-
	Total Other		1,165	500	3,830	4,950	300
	Other NOx Projects (SCRs)		-	250	3,250	1,200	-
	Other Effluent Guidelines/NPDES		75	-	-	-	-
	Other CEMS Projects		110	-	400	750	-
	Other Cooling Tower/Intake Structure		980	250	180	3,000	300

Table 5 – Hydro Generation Environmental Capital Expenditures for 2016–2020

Official 2016 Capital Budget ($000)

	DESCRIPTION	PE	2016	2017	2018	2019	2020
Hydro	Weiss - Install Oxygenation System	246101	1,300	2,700	-	-	-
Hydro	Henry - Install Oxygenation System	253101	3,000	-	-	-	-
Hydro	Coosa System - Adaptive Mgmt Plan for Habitat of Endangered Species	259202	300	-	500	-	-
Hydro	Logan Martin - Install Oxygenation System	259901	1,300	2,700	-	-	-
	Total Hydro		5,900	5,400	500	-	-
	Hydro Aeration and Minimum Flow Projects		5,900	5,400	500	-	-

ESTIMATED ENVIRONMENTAL O&M EXPENSE FOR 2016 – 2020

Table 6 – Environmental O&M Expense for 2016-2020

2016 O&M Budget and Forecast

Activity	Environmental Activities	2016	2017	2018	2019	2020
E316A	316A REGULATION	41,082	170,698	175,818	181,093	184,715
E316B	316B REGULATION	41,082	219,969	226,569	233,366	238,033
EDISP	ENVIRO DISPOSAL ACTIVITY-ENVIRO AFFAIRS COMPLIANCE	231,417	238,361	245,511	252,877	257,935
EHYDR1	COOSA/WARRIOR/TALLAPOOSA SHORELINE STUDIES, ESA ST	465,000	465,000	465,000	465,000	474,300
EHYDR11	ENVIRO FISH CULTURE FACILITY	-	475,000	297,000	286,000	291,720
EHYDR12	ENVIRO FISHERIES HABITAT ENHANCEMENT	-	359,000	238,000	229,000	233,580
EHYDR9	ENVIRO WILDLIFE HABITAT ENHANCEMENT&RESTORATION	182,000	182,000	182,000	182,000	185,640
EMERC	ENVIRONMENTAL MERCURY RATA TESTING	1,814,918	1,857,507	1,901,152	1,945,881	1,984,799
F34	COMPLIANCE-ENVIRONMENTAL	25,665,375	26,339,503	24,496,612	24,259,432	24,874,314
F8A	ASH SALES	(2,157,344)	(2,157,344)	(2,157,344)	(2,157,344)	(2,200,493)
F8E	OTHER ENVIRONMENTAL	97,628	100,291	778,303	106,395	109,885
F8G	GYPSUM SALES	(518,349)	(518,349)	(518,349)	(518,349)	(528,720)
FAAE	ASH SLUICE-ENVIRONMENTAL	524,132	569,056	605,044	610,755	615,806
FAC	FLY ASH	2,462,489	2,799,171	2,922,280	3,005,127	3,009,987
FAD	NPDES TREATMENT	6,567,031	6,621,468	7,091,938	7,611,369	8,383,736
FAE	ASH DISPOSAL	3,848,541	3,802,347	3,774,943	3,760,894	3,839,929
FAF	PRECIPITATOR	6,409,925	7,852,455	7,350,488	8,471,726	6,290,385
FAFE	PRECIP. FLUE GAS CONDITIONING	175,000	180,250	185,658	189,371	195,052
FAG	BAG HOUSE	4,243,951	9,360,945	12,410,841	11,390,039	6,652,650
FAY	ASH HANDLING SYSTEM	2,359,212	2,009,506	2,283,939	2,863,245	2,497,278
FBF	STACK	767,693	822,964	779,232	831,158	785,658
FBH	CEMS-ALL ASSOC. DEVICES	2,358,102	2,549,426	2,525,941	2,700,870	2,593,948
FBKA	ACTIVATED CARBON INJECTION (ACI)	10,896,794	12,449,082	13,483,203	14,055,105	14,603,842
FBKB	SULFURIC ACID MIST CONTROL (SAMC)	2,608,395	3,065,735	3,395,182	3,634,869	3,808,986
FBKC	DRY SORBENT INJECTION (DSI)	5,025,258	5,120,418	3,655,567	3,728,678	3,843,935
FBKE	BROMINE INJECTION	1,332,858	1,336,841	1,343,250	1,347,651	1,379,115
FDA	DUST SUPPRESSION	6,573,443	7,664,231	7,716,309	7,785,364	7,967,438
FHK	COOLING TOWERS	4,282,632	3,917,239	4,476,756	4,018,178	4,113,513
FNF	WASTE WATER	920,467	2,017,808	2,894,519	3,075,508	3,035,200
FTE	ENVIRONMENTAL PROJECTS (HYDRO)	3,186,061	3,251,707	3,319,836	3,390,407	3,469,502
FVK	WATER/STEAM INJECTION SYSTEM	82,061	119,347	175,305	175,727	176,156
FXA	FLUE GAS HANDLING	2,088,498	2,307,081	2,206,395	2,429,879	2,424,903
FXB	LIMESTONE HANDLING	24,046,816	25,875,814	27,041,169	28,476,401	28,771,454
FXC	SCRUBBER VESSEL	3,748,999	4,407,327	3,678,238	5,345,391	3,751,456
FXD	GYPSUM HANDLING	4,220,426	4,259,315	5,447,461	5,229,327	5,225,607
FXE	RETURN WATER	36,087	36,087	51,468	51,468	51,468
FXF	MAKE-UP WATER	83,091	73,091	68,896	116,396	60,024
FXG	SUBSTATION/SWITCHYARD	8,624	9,018	10,398	10,796	10,794
FXJ	GAS COOLING/RECYCLE SPRAY	500,998	667,067	626,459	999,692	635,962
FXK	STATION SERVICE	42,586	328,258	281,366	334,470	282,042
FXL	GYPSUM DRAW-OFF	181,810	174,374	218,043	219,836	220,851
FXM	OXIDATION AIR	30,000	55,000	55,900	56,673	32,000
FXN	WATER TREATMENT	8,000	8,000	12,500	12,600	12,600
FXP	SERVICE FACILITIES-SCRUBBER SYS	375,383	361,712	458,371	461,199	476,460
FXR	FIRE PROTECTION-SCRUBBER SYS	25,112	25,112	27,892	28,407	28,792
FXS	AIR SYSTEM-SCRUBBER SYS	341,615	336,615	344,065	397,357	353,818
FXY	SCRUBBER SYSTEM	9,365,806	11,730,727	15,859,267	14,103,496	15,060,268
FXZ	INSTRUMENTS AND CONTROLS-SCRUBBER SYS	28,836	28,836	40,277	40,317	40,379
FYA	AMMONIA UNLOADING/STORAGE AREA	11,911,484	11,864,778	12,478,435	12,797,737	12,884,245
FYB	AMMONIA FORWARDING SYSTEM	44,816	45,182	61,060	62,289	63,535
FYC	AMMONIA VAPORIZATION SKID	77,083	79,083	79,083	86,583	83,418
FYD	AMMONIA INJECTION GRID	50,000	63,837	63,021	63,837	64,021
FYE	REACTOR BOXES	178,291	790,121	708,827	814,402	717,534
FYF	AUXILIARY SYSTEMS	200,489	303,501	296,635	304,663	301,395
FYH	SNCR	680,067	752,368	699,853	713,240	788,083
FYY	SELECTIVE CATALYTIC REDUCTION	3,146,556	1,987,089	4,388,408	2,623,858	2,479,714
FYZ	INSTRUMENTS AND CONTROLS-SCR	337,021	349,265	357,361	365,841	374,569
Total		152,245,348	170,160,290	182,281,351	184,257,547	178,563,216

ENVIRONMENTAL CAPITAL PLACED IN SERVICE FOR 2016

GENERATION, TRANSMISSION & DISTRIBUTION

Alabama Power Company
2016 Environmental Projects Placed In Service
Generation, Transmission and Distribution
$000

Plant	Project	PE	Jan - 2016	Feb - 2016	Mar - 2016	Apr - 2016	May - 2016	Jun - 2016	Jul - 2016	Aug - 2016	Sep - 2016	Oct - 2016	Nov - 2016	Dec - 2016	2016
Barry CC	APC-187139: UNIT 6 - COOLING TOWER FANS	APC-1871					250								250
Barry CC	APC-187140: UNIT 7 - COOLING TOWER FANS	APC-1871											250		250
Barry CC	APC-187171: BARRY UNIT 6 COOLOING TOWER TRANSFORMER REPLACEMENT	APC-1871			180										180
Barry CC	APC-187172: BARRY UNIT 7 COOLING TOWER TRANSFORMER REPLACEMENT	APC-1871												100	100
Barry CC		Sub-Total Barry CC			180		250						250	100	780
		Accumulated Sub-Total			180	180	430	430	430	430	430	430	680	780	
Barry Steam Plant	APC-034916: DRY SORBENT INJECTION	APC-0349	57	13	13	364									447
Barry Steam Plant	APC-034917: ACTIVATED CARBON INJECTION	APC-0349	46	4	7	230									287
Barry Steam Plant	APC-039940: BARRY 5 - MRCS	APC-0399												9,349	9,349
Barry Steam Plant	APC-049802: COAL HANDLING PROJECTS CCO	APC-0498										550			550
Barry Steam Plant		Sub-Total Barry Steam Plant	103	17	20	594						550		9,349	10,633
		Accumulated Sub-Total	103	120	140	734	734	734	734	734	734	1,284	1,284	10,633	
Gadsden Steam Plant	APC-064608: GADSDEN 1-2 CCR WASTE WATER MANAGMENT	APC-0646												9,304	9,304
Gadsden Steam Plant		Sub-Total Gadsden Steam Plant												9,304	9,304
		Accumulated Sub-Total												9,304	
Gaston Steam Plant	APC-066501: UNIT 5 - COOLING TOWER FILL	APC-0665												800	800
Gaston Steam Plant	APC-069912: SCRUBBER AGITATOR GEARBOX	APC-0699												250	250
Gaston Steam Plant	APC-069921: ACI	APC-0699				4,168	10	10	11	10	9	5			4,223
Gaston Steam Plant	APC-069922: SAMC	APC-0699	3,437	395	542	48	17	10	10	10	10	10	10		4,459
Gaston Steam Plant	APC-069925: BAGHOUSE	APC-0699				345,669	3,409	1,007	604	575	531	189			351,984
Gaston Steam Plant	APC-069937: SCRUBBER NOZZLES	APC-0699												750	750
Gaston Steam Plant	APC-069940: SCRUBBER GAS EXPANSION JOINTS	APC-0699												2,100	2,100
Gaston Steam Plant	APC-069952: U5 SCRUBBER PREQUENCH LANCES	APC-0699					900								900
Gaston Steam Plant	APC-070901: UNIT 5 REPLACE CEMS EQUIPMENT	APC-0709		400											400
Gaston Steam Plant		Sub-Total Gaston Steam Plant	3,437	795	542	349,885	4,336	1,027	625	595	550	204	10	3,900	365,906
		Accumulated Sub-Total	3,437	4,232	4,774	354,659	358,595	360,022	360,647	361,242	361,792	361,996	362,006	365,506	
Gorgas Steam Plant	APC-111307: CONTROLS FOR ASH PUMPING STATION	APC-1113	50	25	25										100
Gorgas Steam Plant	APC-113725: UB-10 BAGHOUSE	APC-1317	3,311	4,224	3,177	1,515	586	1,133							13,946
Gorgas Steam Plant		Sub-Total Gorgas Steam Plant	3,361	4,249	3,202	1,515	586	1,133							14,046
		Accumulated Sub-Total	3,361	7,610	10,812	12,327	12,913	14,046	14,046	14,046	14,046	14,046	14,046	14,046	
Greene County Steam Plant	APC-119919: U1 GAS CONVERSION	APC-1199						12,900	363	60					13,323
Greene County Steam Plant	APC-124919: U2 GAS CONVERSION	APC-1249							11,043	49					11,092
Greene County Steam Plant	APC-129906: GAS CAPABILITY COMMON EQUIPMENT	APC-1299						3,634	60	6					3,700
Greene County Steam Plant		Sub-Total Greene County Steam Plant						16,534	11,466	115					28,115
		Accumulated Sub-Total						16,534	28,000	28,115	28,115	28,115	28,115	28,115	
Miller Steam Plant	APC-133403: REPLACE SCR CATALYST LAYER	APC-1314	2,042	46											2,088
Miller Steam Plant	APC-133420: BOOSTER FAN HUB REPLACEMENT (A&B)	APC-1316				919									919
Miller Steam Plant	APC-133422: U1 MRCS INSTALLATION	APC-1314	3,317												3,317
Miller Steam Plant	APC-133204: Dust Valve Replacement	APC-1332				1,058									1,058
Miller Steam Plant	APC-141819: BOOSTER FAN HUB REPLACEMENT	APC-1418				919									919
Miller Steam Plant	APC-141820: UNIT 2 - MRCS INSTALLATION	APC-1418	2,561												2,561
Miller Steam Plant	APC-142004: DUST VALVE REPLACEMENT	APC-1420			744										744
Miller Steam Plant	APC-143301: REPLACE PRECIPITATOR INTERNALS	APC-1433				90,559									90,559
Miller Steam Plant	APC-143701: Replace SCR Catalyst	APC-1437	1,940	46											1,986
Miller Steam Plant	APC-145101: COOLING TOWER FILL REPLACEMENT	APC-1451				12,043									12,043
Miller Steam Plant	APC-145108: CT SODIUM HYPOCHLORITE SYSTEM	APC-1451			230										230
Miller Steam Plant	APC-145204: UNITS 1&2 - CEMS DATALOGGERS	APC-1452				103									103
Miller Steam Plant	APC-145902: REPLACE SW COOLING TOWER BATTERY SYSTEM	APC-1459			110										110
Miller Steam Plant	APC-150341: U1-4 REPLACE GYPSUM DEWATERING BATTERY	APC-1503				288									288
Miller Steam Plant	APC-150342: U1-4 INSTALL FGD WASTER WATER PIPING & VALVES	APC-1503				959									959
Miller Steam Plant	APC-150343: U1-4 REPLACE SEWER TREATMENT PLANT PUMPS	APC-1503				48									48
Miller Steam Plant	APC-154202: HYDROBIN VALVES AND GATES	APC-1542												144	144
Miller Steam Plant	APC-154310: REPLACE ASH SILO AIR OPERATED VALVES	APC-1543												39	39
Miller Steam Plant	APC-154311: REPLACE ASH SILO SCAVANGER AIR FANS	APC-1543												24	24
Miller Steam Plant	APC-157524: UNIT 3 MRCS INSTALLATION	APC-1575	2,943												2,943
Miller Steam Plant	APC-157527: U3 REPLACE AMMONIA FORWARDING PUMPS	APC-1575	100												100
Miller Steam Plant	APC-164524: UNIT 4 - MRCS INSTALLATION	APC-1645	2,057												2,057
Miller Steam Plant	APC-164527: U4 REPLACE AMMONIA FORWARDING PUMPS	APC-1645				100									100
Miller Steam Plant	APC-170605: U3&4 INSTALL CT SODIUM HYPOCHLORITE SYSTEM	APC-1706				150									150
Miller Steam Plant		Sub-Total Miller Steam Plant	14,960	92	1,084	107,246								207	123,589
		Accumulated Sub-Total	14,960	15,052	16,136	123,382	123,382	123,382	123,382	123,382	123,382	123,382	123,382	123,589	
Theodore CC	APC-183224: Neutralization Tank Pumps (Waste Water)	APC-1832										75			75
Theodore CC		Sub-Total Theodore CC										75			75
		Accumulated Sub-Total										75	75	75	
Washington County CC	APC-182307: CEMS FOR PACKAGE BOILER	APC-1823	110												110
Washington County CC	APC-182407: SIDE STEAM FILTRATION SYSTEM FOR COOLING TOWERS	APC-1824												200	200
Washington County CC		Sub-Total Washington County CC	110											200	310
		Accumulated Sub-Total	110	110	110	110	110	110	110	110	110	110	110	310	
		Total	21,871	5,153	5,028	459,240	5,172	18,694	12,091	710	550	829	260	23,060	552,758
		Retirements	(348)	(150)	(216)	(17,025)	(330)			(16,807)		(140)	(165)	(822)	(36,003)
	Generation Cumulative Placed In Service 2016 Budget Process		3,645,412	3,650,415	3,655,227	4,097,442	4,102,284	4,120,978	4,133,069	4,116,972	4,117,522	4,118,213	4,118,306	4,140,544	
	Transmission & Distribution Cumulative Placed In Service 2016 Budget Process		32,992	32,992	32,992	32,992	32,992	32,992	32,992	32,992	32,992	32,992	32,992	32,992	

ENVIRONMENTAL O&M EXPENSE FOR 2016

Table 8 – Environmental O&M Expense for 2016

2016 O&M Budget and Forecast

Activity	Environmental Activities	2016
E316A	316A REGULATION	41,082
E316B	316B REGULATION	41,082
EDISP	ENVIRO DISPOSAL ACTIVITY-ENVIRO AFFAIRS COMPLIANCE	231,417
EHYDR1	COOSA/WARRIOR/TALLAPOOSA SHORELINE STUDIES, ESA ST	465,000
EHYDR11	ENVIRO FISH CULTURE FACILITY	-
EHYDR12	ENVIRO FISHERIES HABITAT ENHANCEMENT	-
EHYDR9	ENVIRO WILDLIFE HABITAT ENHANCEMENT&RESTORATION	182,000
EMERC	ENVIRONMENTAL MERCURY RATA TESTING	1,814,918
F34	COMPLIANCE-ENVIRONMENTAL	25,665,375
F8A	ASH SALES	(2,157,344)
F8E	OTHER ENVIRONMENTAL	97,628
F8G	GYPSUM SALES	(518,349)
FAAE	ASH SLUICE-ENVIRONMENTAL	524,132
FAC	FLY ASH	2,462,489
FAD	NPDES TREATMENT	6,567,031
FAE	ASH DISPOSAL	3,848,541
FAF	PRECIPITATOR	6,409,925
FAFE	PRECIP. FLUE GAS CONDITIONING	175,000
FAG	BAG HOUSE	4,243,951
FAY	ASH HANDLING SYSTEM	2,359,212
FBF	STACK	767,693
FBH	CEMS-ALL ASSOC. DEVICES	2,358,102
FBKA	ACTIVATED CARBON INJECTION (ACI)	10,896,794
FBKB	SULFURIC ACID MIST CONTROL (SAMC)	2,608,395
FBKC	DRY SORBENT INJECTION (DSI)	5,025,258
FBKE	BROMINE INJECTION	1,332,858
FDA	DUST SUPPRESSION	6,573,443
FHK	COOLING TOWERS	4,282,632
FNF	WASTE WATER	920,467
FTE	ENVIRONMENTAL PROJECTS (HYDRO)	3,186,061
FVK	WATER/STEAM INJECTION SYSTEM	82,061
FXA	FLUE GAS HANDLING	2,088,498
FXB	LIMESTONE HANDLING	24,046,816
FXC	SCRUBBER VESSEL	3,748,999
FXD	GYPSUM HANDLING	4,220,426
FXE	RETURN WATER	36,087
FXF	MAKE-UP WATER	83,091
FXG	SUBSTATION/SWITCHYARD	8,624
FXJ	GAS COOLING/RECYCLE SPRAY	500,998
FXK	STATION SERVICE	42,586
FXL	GYPSUM DRAW-OFF	161,810
FXM	OXIDATION AIR	30,000
FXN	WATER TREATMENT	8,000
FXP	SERVICE FACILITIES-SCRUBBER SYS	375,383
FXR	FIRE PROTECTION-SCRUBBER SYS	25,112
FXS	AIR SYSTEM-SCRUBBER SYS	341,615
FXY	SCRUBBER SYSTEM	9,365,806
FXZ	INSTRUMENTS AND CONTROLS-SCRUBBER SYS	28,836
FYA	AMMONIA UNLOADING/STORAGE AREA	11,911,484
FYB	AMMONIA FORWARDING SYSTEM	44,816
FYC	AMMONIA VAPORIZATION SKID	77,083
FYD	AMMONIA INJECTION GRID	50,000
FYE	REACTOR BOXES	178,291
FYF	AUXILIARY SYSTEMS	200,489
FYH	SNCR	680,067
FYY	SELECTIVE CATALYTIC REDUCTION	3,146,556
FYZ	INSTRUMENTS AND CONTROLS-SCR	337,021
Total		152,245,348

APPENDIX A

ACRONYMS AND ABBREVIATIONS

ACI	Activated Carbon Injection
ADEM	Alabama Department of Environmental Management
ADROP	Alabama Drought Response Operating Proposal
AIR	Additional Information Request
APC	Alabama Power Company
APEA	Applicant Prepared Environmental Assessment
ARP	Acid Rain Program
BA	Biological Assessment
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BO	Biological Opinion
BTU	British Thermal Unit
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CAIR	Clean Air Interstate Rule
CAM	Compliance Assurance Monitoring
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCRs	Coal Combustion Residuals
CEMS	Continuous Emissions Monitoring System
CMMS	Continuous Mercury Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide

CO_2	Carbon Dioxide
COHPAC	Compact Hybrid Particulate Collector
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DRR	Data Requirement Rule
DSI	Dry Sorbent Injection
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPCRA	Emergency Planning and Community Right-to-Know Act
ESP	Electrostatic Precipitator
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FPA	Federal Power Act
FR	Federal Register
FWS	Fish and Wildlife Service – Department of Interior
GHG	Greenhouse Gases
HAP	Hazardous Air Pollutant
Hg	Mercury
HLI	Hydrated Lime Injection
LAER	Lowest Achievable Emission Rate
LNB	Low-NO_x Burner
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards

NAAQS	National Ambient Air Quality Standards
NBP	NO_x Budget Trading Program
NH3	Ammonia
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NPDES	National Pollution Discharge Elimination System
NSPS	New Source Performance Standards
OFA	Overfire Air
OTAG	Ozone Transport Assessment Group
O&M	Operation and Maintenance
PM	Particulate Matter
PM-2.5	Particulate Matter less than 2.5 micrometers in size
PM-10	Particulate Matter less than 10 micrometers in size
PME	Protection Mitigation and Enhancement
PPM	Parts per million
PPT	Parts per trillion
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RCRA	Resource Conservation and Recovery Act
RES	Renewable Electricity Standard
SAMC	Sulfuric Acid Mist Control
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Noncatalytic Reduction

SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
T-Fired	Tangential or tangentially fired
T&E	Threatened and Endangered
TMDL	Total Maximum Daily Load
TR	Transformer/Rectifier
TRI	Toxics Release Inventory
UARG	Utility Air Regulatory Group
USWAG	Utility Solid Waste Activities Group
UWAG	Utility Water Act Group
UVB	Ultraviolet-B
VOC	Volatile Organic Compounds