Alabama Power

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December 11, 2018

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

Re: Rate CNP, Final Environmental Compliance Plan
Docket Nos. 18117 and 18416

Dear Mr. Thomas:

We are enclosing for filing an original and ten (10) copies of the final environmental compliance plan of Alabama Power, under Rate CNP, subpart C. 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. Richard Hutto at (205) 257-2941, who is the designated Company individual under Rule 10 of the Special Rules.

Yours very truly,

PC Raymond

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

Enclosures

hand delivered

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 11, 2018

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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 the **Company**), including regulations and requirements associated with 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, new regulations, as well as changes to existing 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 implementing regulations.

ACID RAIN REQUIREMENTS

The Acid Rain Program was implemented under Title IV of the Clean Air Act Amendments (**CAAA**) of 1990. This program covers fossil fuel-fired power plants across the contiguous United States and requires 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 established a permanent nationwide cap on the total cumulative amount of SO_2 that may be emitted by electric generating units. The program set a specific number of SO_2 "allowances" (one allowance being equivalent to one ton of emitted SO_2) to facilitate achievement of the national goal for SO_2 reductions. The current statutory SO_2 national cap is 8.95 million tons annually, or about one-half of the emissions from the power sector in 1980. 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; and installing emissions control equipment. Since the program began in 1995, Alabama Power has held sufficient SO_2 allowances to cover its annual SO_2 emissions and comply with the Acid Rain Program.

The requirements of the Acid Rain Program were 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 baseline (i.e., Btu heat input to the boiler) 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. Unlike SO_2 emissions, NO_x emissions under the Acid Rain Program are not capped utilizing an allowance trading system. Rather, NO_x emission reductions are achieved through an emission rate-based approach that applies to categories of coal-fired boiler types. The Phase I limits for NO_x are 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 common boiler types 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 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. Every state that has nonattainment areas is required by the CAA to develop and implement a State Implementation Plan (**SIP**) that includes 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 majority of costs for emission controls incurred by Alabama Power are attributable to the implementation of these increasingly stringent air quality standards.

1-Hour Ozone Standard

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 (the **Birmingham 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. 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 the Birmingham area 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 satisfy a limit of 0.21 pounds of NO_x per million Btus of heat input (over a 30-day rolling average) during the ozone season. To meet this mandate, Alabama Power installed, in addition to existing 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 stringent) 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 the Birmingham area did, in fact, attain the 1-hour ozone standard by November 15, 1993, the date required by the CAAA of 1990.

Consequently, in 2002 the Birmingham area retroactively was found to have met the 1-hour standard as of 1993. Birmingham again achieved the 1-hour standard in March 2004, and officially was redesignated to attainment. Unfortunately, attainment was short lived, as in April 2004 the area 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 air pollution that contributes to the formation of ozone in the eastern United States. 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 from power plants and other large combustion industrial sources 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 understated 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 indefinitely. 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. (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 from May 1, 2003 to May 31, 2004 for utilities and large industrial sources in 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. The NBP ended in 2008 with the promulgation of the Clean Air Interstate Rule (discussed later), which ensured continuing NO_x emission reductions from power plants.

8-Hour Ozone Standards

On July 18, 1997, EPA promulgated new ambient air quality standards for ozone. As compared to the original 1-hour ozone standard, the 1997 8-hour ozone standard prescribed a lower ozone concentration level (0.08 ppm vs. 0.12 ppm) and a longer averaging period (8 hours vs. 1 hour). The 8-hour standard also used a different calculation methodology 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 rendered the 1997 8-hour standard 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 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 the area was due June 15, 2007. However, ozone monitoring data for 2003-2005 showed that the Birmingham area was achieving the 1997 8-hour standard. ADEM requested that EPA redesignate the 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.

Even as many areas in the United States were still struggling to meet the 1997 8-hour ozone standard, EPA once again lowered the ozone standard. 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 State of Mississippi. In early 2009, 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, 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 0.075 ppm 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 (the **2015 ozone standard**). Based on ozone monitoring data for 2013–2015, 15 percent of monitored counties in the United States exceeded an ozone standard of 0.070 ppm; however, all of Alabama met the new standard based on 2013–2015 monitoring data. On September 30, 2016, ADEM informed EPA that all monitors in the State of Alabama were meeting the ozone standards and requested that all counties in Alabama be designated as attainment for the 2015 ozone standard. On November 6, 2017, EPA announced initial designations for the 2015 ozone standard for most areas of the United States including the designation of the entire State of Alabama as attainment. Litigation over the 2015 ozone standard is ongoing, however, and the D.C. Circuit court has scheduled oral argument for December 18, 2018, in the cases challenging the 2015 ozone standard. Additionally, EPA has begun a new review of the ozone standard for possible revision, with completion of the review targeted for the end of 2020.

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

Fine Particle Standards

On July 18, 1997, EPA 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 also were 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 the area to attainment. These EPA determinations suspend the requirements for ADEM to submit an attainment demonstration and other SIP elements as long as the Birmingham area continues to meet the standard. However, the most burdensome 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. 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 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 areas 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 upon which to base a determination. EPA deferred the designation for the Columbus-Phenix City area 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 the collection of necessary air quality monitoring data, EPA designated Russell County attainment for the 2012 PM2.5 annual standard on April 7, 2015, completing designations for Alabama. In a final rule issued on September 18, 2017, EPA determined that Alabama's SIP satisfies certain required infrastructure elements relating to the implementation, enforcement and maintenance of the 2012 PM2.5 annual NAAQS. On September 25, 2018, EPA approved Alabama's SIP concerning interstate transport obligations for the 2012 PM2.5 annual standard. With this action, Alabama's SIP demonstrates that air emissions from Alabama do not significantly contribute to nonattainment or interfere with maintenance of the 2012 PM2.5 standard in any other state, and therefore further emissions reductions from Alabama sources are not required to satisfy Alabama's interstate transport obligations. Additionally, and as with the ozone standard noted above, EPA is presently in the NAAQS review process for the PM2.5 standards, with a targeted completion of late 2020.

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 under the CAA's "good neighbor" provision.

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 three separate market-based allowance trading programs: annual SO_2, annual NO_x, and seasonal NO_x. CAIR leveraged 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 it had to meet. The states determined 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 CAIR 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. The court found EPA's CAIR approach to be "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 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 area 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 rule) and other programs (such as the Acid Rain Program), but also to address local attainment of the PM2.5 standards. In addition, the Company has installed SCRs at Plants Barry, Gaston, Gorgas and Miller and baghouses at Plants Gaston and Gorgas. CAIR was ultimately replaced with the Cross-State Air Pollution Rule (discussed below) and its compliance obligations began on January 1, 2015.

Cross-State Air Pollution Rule

On July 6, 2010, EPA signed a proposed 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, becoming more stringent in 2014. Under EPA's "preferred" approach, unlimited interstate trading (for three separate 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.

On July 7, 2011, EPA finalized the proposed rule as 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 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 during the pendency of the stay.

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. 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 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 to EPA, without vacating any part of the rule, to reconsider these emission budgets. The court rejected all other challenges to CSAPR. Although the court ruled that Alabama's CSAPR Phase II SO_2 budget was invalid (i.e., too stringent), ADEM has chosen to implement a CSAPR SIP with the current SO_2 budget so as to avoid further assessments of interstate transport of PM2.5 precursors and regional haze impacts on a state-by-state basis. While this approach will not increase Alabama's SO_2 budget, it fulfills ADEM's interstate transport obligations and enables ADEM to rely on CSAPR to satisfy other obligations under the CAA regarding visibility (discussed below). EPA believes this approach is responsive to the court's remand.

On November 17, 2015, EPA proposed reducing ozone season NO_x emission budgets under CSAPR to address interstate transport of ozone pollution with respect to the 2008 ozone NAAQS. On September 7, 2016, the EPA Administrator signed the **CSAPR Update Rule**, which finalized new lower ozone season NO_x emission budgets for 22 states, including Alabama. The CSAPR Update Rule is the first time EPA has updated an existing program to address transport of air pollution under promulgation of a new air quality standard (i.e., the 2008 ozone NAAQS). The 2016 final rule set an Alabama budget of 13,211 ozone season NO_x allowances, which represents a 58 percent decrease from the original CSAPR ozone season NO_x budget. The new budgets began with the 2017 ozone season (i.e., May through September). The CSAPR Update Rule is under review at the D.C. Circuit, with oral argument recently held on October 3, 2018.

EPA required the CSAPR and CSAPR Update Rules to be initially implemented through FIPs. However, ADEM has largely replaced the CSAPR FIP through a series of Alabama SIP revisions, which have been approved by EPA. These approved Alabama SIP revisions are substantively identical to the corresponding portions of the CSAPR Update Rule FIP, with the exception of ozone season NO_x allowance allocation provisions. ADEM has chosen another allowance allocation methodology for ozone season NO_x allowances instead of the EPA FIP default provisions for compliance periods in 2019 and thereafter.

Additionally, on July 10, 2018, EPA proposed for 20 covered states including Alabama that the CSAPR Update Rule also addresses interstate transport obligations for the 2008 ozone standard. With this action, EPA would have no obligation to establish additional requirements for sources in these states to further reduce transported ozone to meet the 2008 ozone standard. Finalization of this action remains pending.

The installation by Alabama Power of SCRs and scrubbers has helped to ensure compliance with CSAPR and the CSAPR Update Rule and will contribute to compliance efforts by the Company with subsequent additional transport rules EPA may promulgate.

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 **2010 NO_2 standard**). The rule required new roadside and community wide ambient air quality monitoring in larger urban areas, and the Jefferson County Department of Health installed two NO_2 ambient air quality monitors in Birmingham to meet this requirement. While the rule focused on mobile source emissions near major roadways, the new standard also reached other sources of NO_2 emissions. In June 2010, EPA provided guidance for air quality modeling assessments associated with the new standard. This guidance called for 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 the litigation.

On July 14, 2017, EPA proposed to retain, without revision, both of the current primary NO_2 NAAQS (i.e., the 1-hour standard as well as the annual NO_2 standard). In a final rule issued on April 6, 2018, EPA retained the current standards without revision, based on EPA's review of the most recent science on health effects of NO_2. While the NO_2 standards are not expected to result in any nonattainment issues in Alabama, the stringency of the 1-hour NO_2 standard remains a concern in air quality modeling associated with air permitting.

SO_2 Standards

In June 2010, EPA issued a final rule that revised the NAAQS for sulfur dioxide (SO_2). EPA established a new 1-hour standard of 75 ppb (the **2010 SO_2 standard**) and revoked the existing 24-hour and annual SO_2 standards (effective one year after final area designations for the new standard). Numerous states, industries and groups challenged the revised SO_2 NAAQS rule, but on July 20, 2012, the D.C. Circuit upheld the 2010 SO_2 standard. A petition for review filed with the Supreme Court was denied in January 2013. The 2010 1-hour SO_2 standard further complicated industry's ability to operate coal-fired electric generating units without low sulfur coal and/or scrubbers that reduce SO_2 emissions.

In June 2011, as part of the process for implementing the 2010 SO_2 standard, ADEM recommended to EPA that all areas in Alabama be designated "unclassifiable" for the standard. EPA solicited stakeholder input concerning a provision of the rule that required major SO_2 sources (including all Alabama Power coal-fired power plants) to be modeled, which contributed to delays in area designations. The 2010 SO_2 standard was implemented through a combination of ambient air quality monitoring and computer dispersion modeling, deviating from the traditional method of establishing attainment based only on ambient air monitoring data. Area designations were done in separate rounds, based on the use of monitoring data and modeling. On July 25, 2013, EPA designated 29 areas in 16 states (but did not designate other areas) as nonattainment for the 2010 SO_2 standard (round one). No areas in Alabama were designated in this first 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 (including Alabama) filed comments in opposition, but on March 2, 2015, the court accepted the consent decree as an enforceable order. The court's order directed EPA to complete designations for the SO_2 NAAQS in three additional rounds by prescribed dates. Alabama Power's Plant Greene County was originally affected by the decree; however, the Company's decision to convert the boilers on Greene County 1-2 to fire only natural gas rendered the consent decree inapplicable there.

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 was established for state air agencies to characterize SO_2 air quality and to provide that air quality data to EPA. The schedule required state air agencies to submit to EPA, by January 15, 2016, a list identifying SO_2 emitting facilities (including fossil fuel-fired electric generating plants) around which air quality is to be characterized, as well as sources with SO_2 emissions above 2,000 tons per year. ADEM submitted the list of sources that must meet the requirements of the DRR, which included Alabama Power's Plants Barry and Gaston. EPA subsequently added Plant Gorgas to the list of sources it believed to be affected by the DRR. 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 chose modeling, the analysis was due to EPA by January 13, 2017, with designations finalized by December 2017. For facilities that chose air monitoring, monitors were to be sited and operational by January 1, 2017, with designations 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 2,000 tons per year, these limits were effective as of January 13, 2017.

Pursuant to the court-ordered schedule in the March 2015 consent decree, EPA finalized additional designations on July 2, 2016 (round two). On this date, EPA designated four areas as nonattainment, 16 areas as unclassifiable, and 41 areas as unclassifiable/attainment for the 1-hour SO_2 standard (a total of 61 areas in 24 states). In November 2016, EPA supplemented round two by designating three additional areas as nonattainment and one additional area as unclassifiable (all in Texas).

In accordance with the DRR, Alabama Power submitted in January 2017 modeling characterizing SO_2 air quality around Plants Barry, Gaston, Gorgas and Miller (Plant Miller was modeled with

Plant Gorgas due to the close proximity of these plants to each other). In light of the conversions to natural gas at Plants Gadsden and Greene County, ADEM has not been required to characterize air quality around these plants regarding the DRR and SO_2. The submitted modeling data demonstrated that the air quality around the modeled Alabama Power plants meets the 1-hour SO_2 standard. Based in part on this information, EPA issued final third round designations on December 21, 2017, for the 1-hour SO_2 air quality standard including most areas in Alabama. All areas in Alabama were designated "attainment/unclassifiable" or "unclassifiable" except for a portion of Shelby County, Alabama, which will be designated by December 2020 based on ambient monitoring data.

On June 8, 2018, EPA proposed to retain the current 1-hour SO_2 air quality standard that was set in 2010 without revision. Comments on the proposal were due July 23, 2018, and EPA has indicated finalization of this rulemaking by January 2019.

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 only 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: 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 to EPA scheduled for 2018, 2028, 2038, 2048 and 2058. 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. On January 10, 2017, EPA finalized regional haze revisions that amended requirements for state CAVR plans. This rule included an extension of the deadline for the next regional haze SIP submittal from July 31, 2018 to July 31, 2021. EPA stated this date change will allow states to obtain and take into account information on the effects of a number of other regulatory programs impacting sources over the next few years and will better integrate state planning with these other programs.

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, EPA indicated support for CSAPR being equivalent to BART for SO_2 and NO_x emissions for electric generating units in CSAPR-affected states. ADEM adopted CSAPR as equivalent for BART for SO_2 and NO_x in the Alabama CAVR SIP. On September 29, 2017, EPA affirmed the continued validity of its determination that CSAPR is equivalent to BART. On October 12, 2017, EPA finalized four actions regarding regional haze and visibility obligations in Alabama's SIP. These actions included: (i) approval of Alabama's SIP revision seeking to change reliance from CAIR to CSAPR for certain regional haze requirements; (ii) conversion of EPA's prior limited approval/limited disapproval of Alabama's 2008 CAVR SIP to full approval; (iii) approval of visibility requirements of Alabama's SIP submittals for the 2012 PM2.5, 2010 NO_2, and 2010 SO_2 NAAQS; and (iv) conversion of EPA's disapproval of the visibility portion of Alabama's SIP for the 2008 ozone NAAQS to an approval.

Subsequently, EPA determined that compliance with CSAPR is better than BART for individual sources affected by CAVR. A challenge to that determination led to a March 20, 2018 order from the D.C. Circuit allowing states to treat CSAPR as a compliance option for regional haze SIPs. However, there is another pending case on this issue, leaving reliance on CSAPR as an equivalent to BART unresolved. In September 2018, EPA announced plans to revise the regional haze program, with the goal of (i) returning states to the lead role for compliance, as intended by Congress, (ii) reducing state planning burdens, and (iii) leveraging emission reductions achieved through other CAA programs that further improve visibility in protected areas. A proposed rulemaking is expected in connection with this effort.

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 to review CAMR, 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 and 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). For existing sources, compliance would begin three years from the effective date of the final rule (April 16, 2015), unless a compliance extension is granted.

Following promulgation of the final MATS rule, EPA received several administrative petitions to reconsider aspects of the rule. The D.C. Circuit also received several petitions for review of the final rule. On April 15, 2014, the court issued its opinion, denying all petitioners' challenges. 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. On December 15, 2015, the D.C. Circuit issued an order remanding the MATS proceedings to EPA without vacatur for EPA to consider cost. On April 25, 2016, the EPA published the final "Supplemental Finding that it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units" (**MATS Supplemental Finding**). EPA concluded that a consideration of cost does not cause a change to the determination that regulation of HAP emissions from EGUs is appropriate and necessary. Several petitions for review of the MATS Supplemental Finding were filed in the D.C. Circuit in mid-2016. On April 27, 2017, the D.C. Circuit granted EPA's motion to postpone oral argument and hold the case in abeyance while EPA conducts a review of the MATS Supplemental Finding.

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 implemented 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

In April 2007, the Supreme Court ruled that EPA has authority under the current CAA to regulate greenhouse gas (**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. However, it affirmed 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's 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 in the *Federal Register* its proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units. 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 to 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." (Note, 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 implementation plans to EPA 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 (**CPP**), 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 plant 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, a state either fails to submit a state plan in response to the final guidelines or its plan is not approved by EPA.

On February 9, 2016, the Supreme Court granted a stay of the Clean Power Plan. With the rule stayed, the requirement for state plan submittals was suspended. The stay will remain in effect until litigation is concluded or the Supreme Court otherwise terminates it. On September 27, 2016, oral argument of the CPP was held before the full panel of judges in the D.C. Circuit. On March 28, 2017, the President signed Executive Order 13783 "Promoting Energy Independence and Economic Growth", which among other provisions directs EPA to review the CPP (and the final rule applying to new sources) and, if appropriate and as soon as practicable, issue proposed rules suspending, revising, or rescinding the rules. Also on March 28, 2017, EPA filed a motion with the D.C. Circuit to hold litigation of the CPP in abeyance. On April 4, 2017, EPA initiated a review of the CPP as a result of Executive Order 13783. On April 28, 2017, the D.C. Circuit issued a temporary (60-day) abeyance of the CPP litigation. Through a series of subsequent court orders, the CPP case remains held in abeyance. On October 16, 2017, EPA proposed to repeal the CPP and initiated a 60-day comment period on that proposal (which was subsequently extended through January 16, 2018). EPA also indicated that it would separately ask for comment on whether to replace the CPP, which subsequently it did through an advanced notice of proposed rulemaking issued December 27, 2017.

On August 31, 2018, EPA proposed a replacement rule for the CPP, named the Affordable Clean Energy Rule (**ACE**). ACE would provide emission guidelines that inform the development and implementation of state plans to reduce GHG emissions from existing fossil-fired steam generating units. As proposed, ACE would largely apply to existing coal-fired electric generating units and not to natural gas-fired combined cycle and combustion turbine units. States must evaluate affected units against "candidate technologies" and identify the "best system of emission reduction" that can be applied to achieve heat rate or efficiency improvements for each unit. ACE also includes an optional hourly emissions test for determining whether New Source Review is triggered in implementing any heat rate improvement project. States would have three years to submit plans after the EPA emission guidelines are finalized. EPA has indicated it would like to finalize ACE in early 2019.

On June 30, 2016, EPA proposed the Clean Energy Incentive Program (**CEIP**), a voluntarily, early action program that could provide emission rate credits or allowances (earned through implementation of certain demand-side energy efficiency and/or zero-emitting renewable energy projects) for use in compliance with the Clean Power Plan. On April 3, 2017, EPA withdrew this proposed rule as well as the federal plan and model rule (discussed above).

On September 3, 2016, the U.S. Administration joined the Paris Agreement (which includes a goal to hold global average temperature to no more than 2°C above pre-industrial levels). The Paris Agreement states that "the Agreement shall enter into force on the thirtieth day after the date on which at least 55 Parties to the Convention accounting in total for at least an estimated 55 percent of the total global greenhouse gas emissions have deposited their instruments of ratification, acceptance, approval or accession." The Paris Agreement entered into force on November 4, 2016. On June 1, 2017, the President announced that the United States will withdraw from the Paris Agreement and begin negotiations for re-entry or negotiate a new agreement with more favorable terms for the United States. At this time, the implications of the Paris Agreement or any future international accord or treaty are unknown.

Lastly, Congress has considered many legislative proposals that would reduce emissions of GHGs 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. The prospect for any such legislation remains uncertain 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 or closed-loop ash handling, high levels of treatment for flue gas desulfurization (**FGD**) wastewater, treatment of non-chemical metal cleaning wastes, and restrictions on the flow and reuse of plant water. The compliance date for meeting the Effluent Limitation Guidelines (**ELG**) rule was November 1, 2018, with the latest possible compliance date of December 23, 2023. On September 18, 2017, EPA released a final postponement rule that delays the earliest compliance date for bottom ash transport water (**BATW**) and FGD wastewater streams from November 1, 2018 to November 1, 2020. EPA projects rulemaking on these wastewater streams to be finalized by 2020. Due to overlapping requirements of the Coal

Combustion Residuals (**CCR** or **CCRs**) and ELG rules, the Company plans to have dry or hybrid bottom ash systems and new low volume wastewater treatment systems in place by the end of 2018 or early 2019 to comply with the CCR rule rather than the ELG. The Company is currently evaluating the need for compliance deadline extensions for certain waste streams at each plant.

Impacts of MATS Rule on Water Treatment

As part of the Company's compliance with the MATS rule, calcium bromide and brominated activated carbon are used to capture mercury from the combustion gas. The mercury removed from the air and the bromide used for the removal of mercury can be transferred to the plant process water. Municipal water suppliers have to meet very low levels of halide compounds in drinking water, and based on their treatment methods, there is a possibility that bromide can impact the levels of halide compounds, especially during low flow periods. The Company began an ADEM-approved study in 2016 to evaluate the levels of bromide and mercury in both plant and river water. Alabama Power continued sampling under the applicable ADEM plan in 2017 and 2018.

Clean Water Act (CWA) Section 316(a)

A focus on thermal issues has arisen due to EPA's renewed 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 except Gadsden 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. The new Gadsden permit contains some modified and more stringent thermal requirements based on modeling performed by ADEM. The Company also has begun thermal modeling studies to potentially be used in the next permit cycle.

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."

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 the installation of "fish friendly" traveling screens and fish return troughs.

The Company performed entrainment sampling in 2017 and 2018 to meet the requirements under the rule, and expects ADEM to specify a schedule to submit the required studies in the NPDES permit renewal for each affected plant.

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 (**NMFS**) 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, including the provision giving FWS veto power over draft NPDES permits. The U.S. Court of Appeals for the Second Circuit recently denied all petitions to the rule. As a result, the final rule stands unchanged and in full effect. Alabama Power had been operating as if the rule would not change and has proceeded with the needed studies in order to comply with the 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 U.S. Army Corps of Engineers (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, Regional 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 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 using wetland mitigation banks managed either by the Company or by others in Alabama.

Previously, 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). On August 28, 2015, EPA redefined the "Waters of the United States" (**WOTUS** or **2015 WOTUS Rule**) 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. The application of the revised rule is very site specific and could cause compliance issues in the future should it stand.

On July 27, 2017, EPA and the Corps of Engineers released a proposed rule to recodify the regulatory text defining WOTUS that was in place prior to the Clean Water Rule. On January 22, 2018, the Supreme Court held that the federal district courts have jurisdiction over challenges to the 2015 WOTUS Rule (and not the circuit courts of appeal). This decision has set into motion various actions by EPA, the Corps of Engineers, the Department of Justice, and the federal courts. On February 28, 2018, the Sixth Circuit Court of Appeals lifted its nationwide stay of the 2015 WOTUS Rule that had been in place since October 9, 2015. At the same time, the Sixth Circuit dismissed all of the cases pending before it, consistent with the Supreme Court's decision. Notwithstanding the lifting of the nationwide stay of the 2015 WOTUS Rule, the rule is not scheduled to go into effect until February 6, 2020. As a result, EPA and the Corps of Engineers have taken steps to finalize a repeal and replacement rule (Step 1) and propose a replacement WOTUS definition (Step 2) by late 2018. The EPA's and the Corps of Engineers' supplemental proposal to their 2017 proposed rule to repeal the 2015 WOTUS Rule and recodify the prior regulatory text defining WOTUS was published in the Federal Register on July 12, 2018. EPA and the Corps of Engineers have identified some issues they believe may warrant further public comment, which are addressed in the supplement to the proposed repeal. It is likely that any final rule will be challenged.

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 (as issued by FERC) 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 were 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 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 requested that FERC correct this misinterpretation and change the license articles related to water quality to reflect the appropriate state water quality standard. Several other parties, including the Georgia Environmental Protection Division, the Atlanta Regional Commission, and Alabama Rivers Alliance and American Rivers also filed for rehearing of the Coosa License. These parties challenged several aspects of the Coosa License and requested FERC to require Alabama Power to meet an even more stringent standard of 5.0 ppm dissolved oxygen at all times.

On April 21, 2016, FERC issued an order on rehearing that corrected the misinterpretation of the water quality certification and changed the license requirement to 4.0 ppm dissolved oxygen during generation. In addition, the order finalized all other requirements of the license. The other rehearing requests from the parties listed above were denied. Alabama Power started implementing the terms of the new license including receiving agency and FERC approvals on various management plans.

In order to meet the existing state standard of 4.0 ppm during generation, new and upgraded turbine aeration systems were necessary at several facilities. These systems were installed and operational by the FERC compliance date and the start of the ADEM monitoring season. Alabama Power had planned to monitor and report for three years at all Coosa facilities to ensure water quality requirements were met.

Alabama Rivers Alliance and American Rivers appealed the April 21, 2016 FERC order on the Coosa license in the D.C. Circuit over National Environmental Policy Act **(NEPA)** and Endangered Species Act **(ESA)** issues. The Company participated in the litigation in support of FERC and the FWS.

On January 12, 2018, the D.C. Circuit held an oral argument in the Coosa license appeal. Alabama Power was an intervenor in the appeal and was not given an opportunity to participate in the oral argument. On July 6, 2018, the D.C. Circuit court vacated the Coosa License and remanded it back to FERC for further proceedings. Additionally, the Court deemed the biological opinion that the license relied on as unlawful.

On September 10, 2018 FERC issued a Notice of Reinstatement of Authorization for Continued Project Operation that reinstates the three August 8, 2007 Notice of Authorizations and returns the July 28, 2005 application for the Coosa Project to pending. Based on discussions with FERC, Alabama Power anticipates that within the next few months, FERC will issue a Notice of Intent (**NOI**) to develop an Environmental Impact Statement. The NOI will also include a detailed schedule for the relicensing process. Following the NOI will be additional information requests from FERC that will inform Alabama Power of the additional data that FERC believes necessary to issue a new license for the project. These efforts will help Alabama Power plan for the work that could be required for the process.

The new licenses for the Martin and the Warrior projects include many other terms and conditions that will result in significant additional capital and operational expenditures over the life of these licenses.

Alabama Power has begun the FERC process to obtain a new operating license for the R.L. Harris Project. This process involves a multi-year evaluation of the environmental, operational, and economic resource issues at the Harris Project. Alabama Power has hosted numerous public and agency meetings over the last year in anticipation of the Harris re-licensing. These meetings covered topics like the history of the dam, the current operations, current use of the lands around the project, and proposed study plans during relicensing. In addition, Alabama Power provided opportunities for stakeholders to bring up any issues they feel should be addressed during re-licensing.

On June 1, 2018, Alabama Power filed an NOI to relicense the project, as well as a Preliminary Application Document (**PAD**, which includes all the information known about the project along with potential issues that have been raised in the meetings discussed above), and draft study plans with FERC. This filing was the official start of the re-licensing process. On July 31, 2018, FERC issued the scoping document for Harris relicensing and requested comments on the PAD that was submitted. FERC held two scoping meetings in Lineville on August 28-29, 2018 to tour the dam and current license recreation sites, as well as solicit feedback from the agencies and public and get input for its NEPA analysis. Alabama Power hosted the first Harris action team meetings in Anniston on September 20, 2018 to get detailed feedback from stakeholders on the proposed study plans. Comments on the FERC scoping document and revised study plans will be filed with FERC by November 13, 2018.

In the spring of 2017, Alabama Power met with ADEM to discuss the possible monitoring locations and intervals for the CWA Section 401 certification. ADEM concurred with the location and the monitoring intervals, and monitoring began June 1, 2017 and will continue through October 31 for the 2017, 2018 and 2019 seasons. This data will be submitted in the 401 water quality certification application that Alabama Power will submit to ADEM prior to filing the license application with FERC.

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 protected status and critical habitat for the Gopher Tortoise to include the entirety of south Alabama. A decision is expected by 2021. Ongoing efforts by multiple agencies and other organizations are aimed at providing management tools that will preclude the need for this additional level of protection.

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. Also 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 into our service territory.

In November 2015, the Black Pine Snake was listed by the FWS as threatened, and FWS is currently accepting comments on a proposal to increase its critical habitat in Clarke County. In April 2015, the Northern Long-Eared Bat was also listed as threatened and it is likely that the tri-colored bat will be added in coming years. The listings of all three species will likely impact transmission line construction. In January 2018 the Black Warrior Waterdog was listed as endangered. Critical habitat has been proposed for Bankhead Reservoir up to Smith Dam.

On October 4, 2017, the FWS proposed listing the Tri-spot Darter as threatened. This small fish is endemic to the upper Coosa River drainage in Alabama and Georgia, and it is known to occur on Alabama Power lands in Alabama. This listing could impact forest management activities in some areas.

In 2015, Alabama Power began consultation with the FWS on the federally endangered Rough Hornsnail (**RHS**) found in the Coosa River. The conditions and restrictions have become part of the Company's Shoreline Permitting Program, in accordance with a Biological Opinion issued by FWS. The Company renewed FWS consultation on the RHS in 2018 in order to provide the maintenance drawdown on Mitchell reservoir. In addition, due to the court finding the 2012 biological opinion relied upon for the Coosa license "unlawful," Alabama Power requested a new biological opinion for Lay reservoir in order to allow for the maintenance drawdown. Additional biological opinion consultations, such as one for drought operations, may be needed prior to a possible new comprehensive Coosa biological opinion that FERC will likely require to support issuance of a new Coosa license.

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 had 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. Historically, the largest TRI releases from coal-fired power plants have consisted of acid gases such as hydrochloric acid, sulfuric acid and hydrogen fluoride. With the installation and operation of scrubbers at several plants, Alabama Power has reduced the release of these aerosols by 95 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 (the **CCR Rule**). 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 (under Subtitle C of RCRA), the stringency of the rule and its various compliance requirements effectively required the closure of wet ash handling facilities and, in some cases, 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. For this reason, Alabama Power encouraged ADEM to adopt the CCR Rule as a state program, which it did effective June 8, 2018. ADEM submitted the state program to the EPA for review and approval in July 2018.

The adoption of the original CCR rule resulted in litigation at the D.C. Circuit. Prior to action by the court, however, EPA announced on July 18, 2018 the finalization of "Phase One, Part One" to the proposed amendments to the CCR rule, which advanced the following EPA objectives:

- Harmonizing CCR and ELG implementation timelines;
- Facilitating development of EPA-approved state CCR permit programs; and
- Clarifying requirements for upcoming CCR milestones that could trigger CCR impoundment closures and remediation.

Thereafter, on August 21, 2018, the D.C. Circuit issued its decision in the CCR litigation. Among other things, the court's decision addressed the following issues:

- Denied EPA's request to hold the case in abeyance;
- Remanded to EPA for further consideration certain challenges by industry regarding (1) regulation of on-site CCR piles destined for beneficial use and (2) the 12,400 ton threshold for the beneficial use criterion;
- Denied relief for remaining industry claims, including the challenge to EPA's authority to regulate inactive surface impoundments; and
- Remanded to EPA for further consideration challenges by certain environmental groups regarding (1) the ability of unlined impoundments to continue operating; (2) the classification of unlined impoundments with two feet of compacted clay as "lined" units; and (3) EPA's failure to regulate legacy ponds.

The consequences of the court's findings for environmental challenges will require EPA to revisit elements of the CCR rule, though the precise actions EPA will have to take still have to be evaluated. Neither the July 18, 2018 rulemaking nor the order of the court immediately affect Alabama Power's commitment to move expeditiously toward closure of unlined ash ponds.

Alabama Power currently operates a number of surface impoundments to store CCR materials. As originally promulgated, the CCR rule excluded facilities that were able to cease using CCRs and close within three years. Alabama Power had planned to close one relatively small ash pond (at Plant Gadsden) under that provision. However, due to litigation, this exclusion was eliminated and the rule's requirements extended to all of the Company's CCR disposal units. 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. Even so, 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.

Ultimately, the compliance scenario for the Company's affected impoundments will encompass a course of closure, along with the requisite facility adaptions to permit closure. In the event a CCR pond is required to close, closure is anticipated to begin in January 2019. With that compliance date in mind, preparations are underway to convert to dry ash handling and pursue alternative treatment for waste waters that were formerly routed to the ash pond and its permitted NPDES discharge point, as well as managing NPDES compliance for dewatering activities that are necessary for pond closure. The Company also is evaluating other strategies, such as possible off-site storage options (as compared to on-site storage options) for coal ash generated in the future and increasing the beneficial reuses of CCRs where possible.

National and local environmental groups have filed lawsuits against other utilities challenging the cap-in-place closure method, even though it has been approved by EPA in the CCR Rule and scientifically proven to be effective in protecting groundwater. In one notable decision issued August 4, 2017, a Tennessee federal district court ordered TVA to close ash disposal facilities at the Gallatin plant by removing all CCRs. The case concerned allegations that ash had migrated to a nearby river, which constituted a violation of the CWA. TVA appealed to the Sixth Circuit Court of Appeals and the ruling was overturned. In another case, a Virginia federal district court found in March 2017 that a Dominion ash pond was in violation of the CWA for similar reasons, but the court did not order closure by removal. That case was appealed to the Fourth Circuit Court of Appeals and the court found that the ash pond was not a "point source" for purposes of the CWA. While the Company believes the outcome of these appeals are consistent with the requirements of the CWA and the CCR rule, the risk of an adverse outcome remains, as petitions for the certiorari to Supreme Court in these cases are being pursued. A requirement to close by removal would introduce new environmental risks, dramatically increase the costs of closure, and adversely impact the quality of life for residents near the plant sites (e.g., resulting in decades of constant truck traffic as part of the removal process).

ESTIMATED ENVIRONMENTAL CAPITAL EXPENDITURES FOR 2019 – 2023

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

GENERATION

Table 1 – Summary of Generation Environmental Capital Expenditures for 2019–2023
(in thousands)

Official 2019 Capital Budget

	2019	2020	2021	2022	2023
NOx Projects (SCRs)	22,262	14,715	20,162	9,564	13,353
SO2 Projects (Scrubbers)	6,511	6,718	6,125	3,959	11,965
CCR-WATER	39,957	-	-	-	-
CCR-LAND	50,450	16,231	51,561	44,411	46,174
Effluent Guidelines/NPDES	111,047	50,138	97,984	119,294	50,357
MATS	2,275	7,701	6,083	127	2,750
Particulate Matter (PM)	34,960	3,899	13,536	1,971	2,100
Hydro Aeration and Minimum Flow Projects	-	350	500	-	-
CEMS Projects	1,050	20	560	239	-
Sewage Treatment	-	-	70	-	-
Cooling Tower/Intake Structure	4,440	4,730	1,280	9,301	10,951
Ecological Projects - Total	272,952	104,503	197,861	188,867	137,650

Air	67,058	33,054	46,466	15,861	30,168
Land	50,450	16,231	51,561	44,411	46,174
Water	155,445	55,218	99,834	128,595	61,307
Ecological Projects - Total	272,952	104,503	197,861	188,867	137,650

Totals may not sum due to rounding

Total CCR Expenditures (Including Cost of Removal by Closure in Place)

	2019	2020	2021	2022	2023
Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	90,407	16,231	51,561	44,411	46,174
Cost of Removal (Closure in Place) for CCR (Not included in above dollars)	231,743	238,391	246,365	252,225	258,289
Total CCR	322,150	254,622	297,926	296,636	304,463

Totals may not sum due to rounding

Table 2 – Summary by Plant of Environmental Capital Expenditures for 2019–2023

(in thousands)

Official 2019 Capital Budget

	2019	2020	2021	2022	2023
Total Barry	57,573	15,059	46,719	24,778	34,177
Barry NOx Projects (SCRs)	450	1,400	3,500	150	1,650
Barry SO2 Projects (Scrubbers)	375	400	2,325	-	4,350
Barry CEMS Projects	100	-	-	-	-
Barry CCR-WATER	3,642	-	-	-	-
Barry CCR-LAND	10,613	2,305	17,616	11,927	12,940
Barry Effluent Guidelines/NPDES	9,943	8,704	9,028	9,015	12,216
Barry MATS	50	-	1,100	-	-
Barry Particulate Matter (PM)	32,400	2,250	13,150	1,650	1,000
Barry Cooling Tower/Intake Structure	-	-	-	2,036	2,021
Total Gadsden	100	-	-	-	-
Gadsden CCR-LAND	100	-	-	-	-
Total Gaston	9,488	35,816	28,744	41,563	26,614
Gaston NOx Projects (SCRs)	1,100	5,005	550	3,850	3,091
Gaston SO2 Projects (Scrubbers)	1,265	2,552	-	330	3,740
Gaston CCR-WATER	792	-	-	-	-
Gaston Effluent Guidelines/NPDES	1,588	16,670	26,764	36,480	13,783
Gaston Particulate Matter (PM)	660	1,485	-	-	-
Gaston CCR-LAND	2,708	743	1,342	726	2,041
Gaston MATS	1,375	7,601	88	77	2,750
Gaston Cooling Tower/Intake Structure	-	1,760	-	100	1,210
Total Gorgas	47,987	37,374	79,525	76,684	27,400
Gorgas NOx Projects (SCRs)	7,500	100	7,750	50	-
Gorgas SO2 Projects (Scrubbers)	250	1,550	3,800	300	250
Gorgas CCR-WATER	319	-	-	-	-
Gorgas CCR-LAND	34,050	10,740	2,018	896	50
Gorgas MATS	-	100	4,895	50	-
Gorgas Particulate Matter (PM)	1,900	100	-	-	-
Gorgas Effluent Guidelines/NPDES	3,768	24,764	60,992	72,697	24,358
Gorgas CEMS Projects	200	20	-	-	-
Gorgas Cooling Tower/Intake Structure	-	-	-	2,691	2,742
Gorgas Sewage Treatment	-	-	70	-	-
Total Greene Co	-	-	-	2,889	2,916
Greene Co Cooling Tower/Intake Structure	-	-	-	2,889	2,916
Total Miller	148,859	12,535	39,543	41,368	44,723
Miller NOx Projects (SCRs)	10,212	7,810	7,112	5,514	8,612
Miller SO2 Projects (Scrubbers)	4,621	2,216	-	3,329	3,625
Miller CCR-LAND	2,854	2,444	30,585	30,862	31,144
Miller CCR-WATER	34,624	-	-	-	-
Miller MATS	800	-	-	-	-
Miller Particulate Matter (PM)	-	64	386	321	1,100
Miller CEMS Projects	-	-	260	239	-
Miller Effluent Guidelines/NPDES	95,748	-	1,200	1,102	-
Miller Cooling Tower/Intake Structure	-	-	-	-	242
Total Other	8,945	3,370	2,830	1,585	1,820
Other NOx Projects (SCRs)	3,000	400	1,250	-	-
Other CCR-WATER	580	-	-	-	-
Other CCR-LAND	125	-	-	-	-
Other Effluent Guidelines/NPDES	-	-	-	-	-
Other CEMS Projects	750	-	300	-	-
Other MATS	50	-	-	-	-
Other Cooling Tower/Intake Structure	4,440	2,970	1,280	1,585	1,820
Total Hydro	-	350	500	-	-
Hydro Aeration and Minimum Flow Projects	-	350	500	-	-

Totals may not sum due to rounding

Table 2 – Summary by Plant of Environmental Capital Expenditures for 2019–2023 (continued)
(in thousands)

Total CCR Expenditures (Including Cost of Removal by Closure in Place)

	2019	2020	2021	2022	2023
Barry Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	14,255	2,305	17,616	11,927	12,940
Barry Cost of Removal (Closure in Place) for CCR (Not included in above amounts)	51,590	52,802	54,026	55,314	56,648
Barry Total CCR	65,845	55,107	71,642	67,241	69,588
Gadsden Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	100	-	-	-	-
Gadsden Cost of Removal (Closure in Place) for CCR (Not included in above amounts)	323	330	337	343	350
Gadsden Total CCR	423	330	337	343	350
Gaston Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	3,500	743	1,342	726	2,041
Gaston Cost of Removal (Closure in Place) for CCR (Not included in above amounts)	6,950	7,113	7,278	7,451	7,631
Gaston Total CCR	10,450	7,856	8,620	8,177	9,672
Gorgas Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	34,369	10,740	2,018	896	50
Gorgas Cost of Removal (Closure in Place) for CCR (Not included in above amounts)	91,994	95,360	100,018	102,392	104,843
Gorgas Total CCR	126,363	106,100	102,036	103,288	104,893
Greene Co Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	-	-	-	-	-
Greene Co Cost of Removal (Closure in Place) for CCR (Not included in above amounts)	12,917	13,220	13,527	13,849	14,183
Greene County Co Total CCR	12,917	13,220	13,527	13,849	14,183
Miller Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	37,478	2,444	30,585	30,862	31,144
Miller Cost of Removal (Closure in Place) for CCR (Not included in above amounts)	67,969	69,566	71,179	72,876	74,633
Miller Total CCR	105,447	72,010	101,764	103,738	105,777
Other Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	705	-	-	-	-
Other Cost of Removal (Closure in Place) for CCR (Not included in above amounts)	-	-	-	-	-
Other Total CCR	705	-	-	-	-

Totals may not sum due to rounding

Table 3(a) – Plant Barry Environmental Capital Expenditures for 2019–2023

(in thousands)

Official 2019 Capital Budget

	DESCRIPTION	PE	2019	2020	2021	2022	2023
BARRY	Unit 1 - CEMS	011506	100	-	-	-	-
BARRY	Unit 4 - Replace C&D Precipitator	028302	-	-	-	-	1,000
BARRY	Unit 4 - Precip Fly Ash Carrier Line Replacement	028305	-	-	2,800	-	-
BARRY	Unit 4 - C & D Precipitator Wash System	028308	500	-	-	-	-
BARRY	Unit 4 - Fly Ash Transport Blower/Motor	028309	-	-	-	-	115
BARRY	Unit 4 - Fly Ash Storage Silo Blower/Motor	028310	-	-	-	-	145
BARRY	Unit 4 - Replace 4A Hydrovacator Tank & Ejector	029303	-	-	600	-	-
BARRY	Unit 4 - Boiler Bottom Ash Containment	030437	-	-	2,000	-	-
BARRY	Unit 4 - Precipitator Replacement Project	034501	25,971	-	-	-	-
BARRY	Unit 4 - Precipitator Ductwork	034503	-	500	6,000	-	-
BARRY	Unit 4 - ACI Blowers	034921	-	-	300	-	-
BARRY	Unit 4 - DSI Blowers	034922	-	-	300	-	-
BARRY	Unit 4 - DSI Air Compressor	034923	-	-	500	-	-
BARRY	Unit 4 - Landfill Phase 1	0349LF	-	150	3,416	3,472	3,538
BARRY	Unit 4 - Intake Screens	0349TS	-	-	-	458	440
BARRY	Unit 5 - Replace Precipitator Rappers (A&B)	035403	1,279	-	-	-	-
BARRY	Unit 5 - C&D Precipitator Control House Roof	035405	-	450	-	-	-
BARRY	Unit 5 - Precipitator Hoists	035406	1,150	-	-	-	-
BARRY	Unit 5 - Precipitator Hopper Heater	035408	3,500	-	-	-	-
BARRY	Unit 5 - Pyrite Carrier Line Replacement	035409	-	150	450	-	-
BARRY	Unit 5 - Pyrite Hopper Replacement	035410	-	150	275	-	-
BARRY	Unit 5 - Boiler Bottom Ash Containment	038904	-	-	3,000	-	-
BARRY	Unit 5 - Fly Ash Transport Blower/Motor	038905	-	-	-	-	180
BARRY	Unit 5 - Fly Ash Storage Silo Air Compressor	038906	-	-	-	-	100
BARRY	Unit 5 - Fly Ash Storage Silo Blower/Motor	038907	-	-	-	-	175
BARRY	Unit 5 - Sulfur Burner Catalyst	039105	-	-	250	-	-
BARRY	Unit 5 - Precipitator Fly Ash Carrier Line Replacement	039110	-	1,300	3,500	-	-
BARRY	Unit 5 - Scrubber Elevator	039520	-	-	-	-	350
BARRY	Unit 5 - SCR Catalyst Replacement	039905	-	1,000	3,400	-	1,000
BARRY	Unit 5 - Scrubber Mist Eliminator	039906	-	150	500	-	-
BARRY	Unit 5 - JBR Gearbox Replacement	039922	-	-	250	-	-
BARRY	Unit 5 - Air Compressor Replacement (Scrubber)	039923	125	-	-	-	-
BARRY	Unit 5 - Scrubber Teflon Expansion Joints Replacement	039929	-	-	500	-	-
BARRY	Unit 5 - Scrubber Make-Up Water Filter	039931	-	-	250	-	-
BARRY	Unit 5 - Scrubber JBR Alignment Grid Replacement	039933	-	-	-	-	2,000
BARRY	Unit 5 - Scrubber Viton Expansion Joint Replacement	039934	-	-	375	-	-
BARRY	Unit 5 - Gas Cooling Duct Replacement	039938	-	-	-	-	2,000
BARRY	Unit 5 - Scrubber Ox Air Blower Resizing/Replacement	039946	250	250	250	-	-
BARRY	Unit 5 - FGD Gypsum Slurry Transfer Pump & Motor Replacement	039952	-	-	100	-	-
BARRY	Unit 5 - FGD Return Water Pump and Motor Replacement	039953	-	-	100	-	-
BARRY	Unit 5 - SCR Sonic Air Horn Compressor Replacement	039956	-	-	-	150	150
BARRY	Unit 5 - SCR Vacuum System	039957	100	-	-	-	-
BARRY	Unit 5 - SCR Flue Gas Fans	039958	350	350	-	-	-
BARRY	Unit 5 - SCR Sonic Air Horns	039959	-	50	100	-	-
BARRY	Unit 5 - SCR Inlet Turning Vanes	039963	-	-	-	-	500
BARRY	Unit 5 - ELG Waste Water Management	0399EG	8,543	8,704	8,848	9,015	9,216
BARRY	Unit 5 - Landfill Phase 2	0399LF	-	355	6,825	6,955	7,087
BARRY	Unit 5 - Intake Screens	0399TS	-	-	-	1,578	1,581
BARRY	Unit 5 - Replace Clinker Grinder	040305	-	-	180	-	-
BARRY	Common 1-5 - Mercury Monitor Replacement	044511	50	-	-	-	-
BARRY	Common 1-5 - Lagoon Addition	046102	125	-	-	-	-
BARRY	Common 1-5 - Fly Ash Transport Air Compressor	046803	-	-	-	-	100
BARRY	Common 1-5 - Fly Ash Transport Area New Hoist Project	046804	200	-	-	-	-
BARRY	Common 1-5 - RSCC Lamella Plate Replacements	046811	-	-	150	-	-
BARRY	Unit 5 - Ash Handling	047409	1,500	1,500	1,500	1,500	1,500
BARRY	Common 1-5 - Barry Ash Pond Non ARO	0474AP	1,000	-	-	-	-
BARRY	Common 4-5 - Dry Bottom Ash	0474BA	7,788	-	-	-	-
BARRY	Common 1-5 - Waste Water Management	0474CR	3,642	-	-	-	-
BARRY	Unit 5 - ELG - Scrubber Return Water	0474EG	1,400	-	-	-	3,000
BARRY	Common 1-5 - Dust Suppression - 4&5 Bunker Floor	049802	-	-	-	1,650	-
	Total Barry		57,573	15,059	46,719	24,778	34,177
	Barry NOx Projects (SCRs)		450	1,400	3,500	150	1,650
	Barry SO2 Projects (Scrubbers)		375	400	2,325	-	4,350
	Barry CEMS Projects		100	-	-	-	-
	Barry CCR-WATER		3,642	-	-	-	-
	Barry CCR-LAND		10,613	2,305	17,616	11,927	12,940
	Barry Effluent Guidelines/NPDES		9,943	8,704	9,028	9,015	12,216
	Barry MATS		50	-	1,100	-	-
	Barry Particulate Matter (PM)		32,400	2,250	13,150	1,650	1,000
	Barry Cooling Tower/Intake Structure		-	-	-	2,036	2,021

Totals may not sum due to rounding

Total Plant Barry CCR Expenditures (Including Cost of Removal by Closure in Place)

	DESCRIPTION	2019	2020	2021	2022	2023
Barry	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	14,255	2,305	17,616	11,927	12,940
Barry	Cost of Removal (Closure in Place) for CCR (Not included in above dollars)	51,590	52,802	54,026	55,314	56,648
	Barry Total CCR	65,845	55,107	71,642	67,241	69,588

Totals may not sum due to rounding

Table 3(b) – Plant Gadsden Environmental Capital Expenditures for 2019–2023

(in thousands)

Official 2019 Capital Budget

	DESCRIPTION	PE	2019	2020	2021	2022	2023
GADSDEN	Replace Pump	064603	100	-	-	-	-
	Total Gadsden		100	-	-	-	-
	Gadsden CCR-LAND		100	-	-	-	-

Totals may not sum due to rounding

Total Plant Gadsden CCR Expenditures (Including Cost of Removal by Closure in Place)

	DESCRIPTION	2019	2020	2021	2022	2023
Gadsden	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	100	-	-	-	-
Gadsden	Cost of Removal (Closure in Place) for CCR (Not included in above dollars)	323	330	337	343	350
	Gadsden Total CCR	423	330	337	343	350

Totals may not sum due to rounding

Table 3(c) – Plant Gaston Environmental Capital Expenditures for 2019–2023

(in thousands)

Official 2019 Capital Budget

	DESCRIPTION	PE	2019	2020	2021	2022	2023
GASTON	Unit 5 - Replace Remote Submerged Chain Conveyor	066208	-	-	-	-	1,100
GASTON	Unit 5 - Bottom Ash Hoppers	066209	550	4,070	-	-	-
GASTON	Unit 5 - Bottom Ash RSCC Bearings	066210	-	-	242	-	275
GASTON	Unit 5 - Bottom Ash Clinker Grinders	066211	-	275	-	-	303
GASTON	Unit 5 - Bottom Ash Hydro Ejectors	066212	-	83	-	-	110
GASTON	Unit 5 - Bottom Ash System Pumps	066213	-	231	-	-	-
GASTON	Unit 5 - Bottom Ash System Valves	066214	220	-	-	242	-
GASTON	Unit 5 - Cooling Tower Fill	066501	-	1,430	-	-	1,210
GASTON	Unit 5 - Power Feed to Cooling Tower	066511	-	330	-	-	-
GASTON	Unit 5 - Catalyst Replacement	069904	1,100	4,840	550	3,850	2,750
GASTON	Unit 5 - Scrubber Sparger Tubes	069910	-	-	-	220	1,650
GASTON	Unit 5 - Scrubber Valves	069919	-	-	-	-	55
GASTON	Unit 5 - Scrubber Motors	069924	-	-	-	110	110
GASTON	Unit 5 - Scrubber Limestone Blowers	069932	880	385	-	-	-
GASTON	Unit 5 - Scrubber Nozzles	069937	-	935	-	-	-
GASTON	Unit 5 - Scrubber Gas Expansion Joints	069940	-	1,100	-	-	1,650
GASTON	Unit 5 - Baghouse Bags	069944	1,375	5,775	-	-	-
GASTON	Unit 5 - Unit 5 - SCR Air Compressors	069947	-	-	-	-	110
GASTON	Unit 5 - SCR Air Dryer	069948	-	-	-	-	55
GASTON	Unit 5 - Ammonia DIVA Control Valve	069956	-	165	-	-	176
GASTON	Unit 5 - Booster Fan Hub Replacement	069971	-	-	-	-	2,750
GASTON	Unit 5 - Baghouse Pulse Air Transmitters	069972	-	880	-	-	-
GASTON	Unit 5 - Add Cathodic Protection on Natural Gas System at Rockford	069973	-	-	-	-	275
GASTON	Unit 5 - Baghouse Expansion Joints	069975	-	880	-	-	-
GASTON	Unit 5 - Scrubber Gas Cooling Header Piping to FGC Scrubber	069980	385	-	-	-	-
GASTON	Unit 5 - Scrubber Gas Cooling Lance Expansion Joints	069984	-	132	-	-	-
GASTON	Unit 5 - Dry Bottom Ash	0699BA	2,048	-	-	-	-
GASTON	Unit 5 - CCC Monitor	0699CC	-	-	-	100	-
GASTON	Unit 5 - ELG Waste Water Management	0699EG	1,038	12,325	26,764	36,480	13,480
GASTON	Unit 5 - Replace Dry Ash Silo Bin Vent Filter Bags	070605	-	-	55	55	-
GASTON	Unit 5 - Replace Air and Motor Operated Valve on Fly Ash	070606	110	209	198	154	220
GASTON	Unit 5 - Precipitator Dust Valve Isolation Gates	070609	660	-	-	-	-
GASTON	Unit 5 - Precipitator Outlet Expansion Joints	070610	-	1,485	-	-	-
GASTON	Unit 5 - Fly Ash Handling Blower	070611	110	-	-	-	248
GASTON	Unit 5 - Fly Ash Handling Blower Motor	070612	-	110	-	220	-
GASTON	Unit 5 - Fly Ash Handling Vacuum Pump	070613	-	-	242	-	-
GASTON	Unit 5 - FA Handling Vacuum Pump Motor	070614	-	110	-	-	-
GASTON	Unit 5 - PAC Ash Blower and Motor	070615	-	-	-	-	88
GASTON	Unit 5 - ACI Bowers	070616	-	-	-	77	-
GASTON	Unit 5 - SAMC Blowers	070617	-	66	88	-	-
GASTON	Unit 5 - Gypsum Pond Pumps	075508	-	-	605	55	-
GASTON	Unit 5 - Gypsum Transfer Pumps	075509	220	-	-	-	-
GASTON	Unit 5 - Gaston Waste Water Management	0835CR	792	-	-	-	-
	Total Gaston		9,488	35,816	28,744	41,563	26,614
	Gaston NOx Projects (SCRs)		1,100	5,005	550	3,850	3,091
	Gaston SO2 Projects (Scrubbers)		1,265	2,552	-	330	3,740
	Gaston CCR-WATER		792	-	-	-	-
	Gaston Effluent Guidelines/NPDES		1,588	16,670	26,764	36,480	13,783
	Gaston Particulate Matter (PM)		660	1,485	-	-	-
	Gaston CCR-LAND		2,708	743	1,342	726	2,041
	Gaston MATS		1,375	7,601	88	77	2,750
	Gaston Cooling Tower/Intake Structure		-	1,760	-	100	1,210

Totals may not sum due to rounding

Total Plant Gaston CCR Expenditures (Including Cost of Removal by Closure in Place)

	DESCRIPTION	2019	2020	2021	2022	2023
Gaston	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	3,500	743	1,342	726	2,041
Gaston	Cost of Removal (Closure in Place) for CCR (Not included in above dollars)	6,950	7,113	7,278	7,451	7,631
	Gaston Total CCR	10,450	7,856	8,620	8,177	9,672

Totals may not sum due to rounding

Table 3(d) – Plant Gorgas Environmental Capital Expenditures for 2019–2023

(in thousands)

Official 2019 Capital Budget

	DESCRIPTION	PE	2019	2020	2021	2022	2023
GORGAS	Unit 8 - CEMS	096902	100	-	-	-	-
GORGAS	Unit 9 - CEMS	101402	100	-	-	-	-
GORGAS	Unit 10 - Replace Precipitator Dust Boxes	107301	1,900	100	-	-	-
GORGAS	Unit 10 - Boiler Bottom Ash Hopper - ELG	108602	-	500	5,000	100	-
GORGAS	Unit 10 - Install Title 1 Clean Air SCR Catalyst	108903	7,500	100	7,500	50	-
GORGAS	Unit 10 - Ammonia Unloading Compressors	108917	-	-	100	-	-
GORGAS	Unit 10 - Ammonia Vaporizers	108918	-	-	150	-	-
GORGAS	Unit 10 - Data Logger-CEMS	108922	-	20	-	-	-
GORGAS	Unit 10 - Clinker Grinders - ELG	110906	325	325	325	350	350
GORGAS	Common 8-10 - Sewage Treatment Blowers	111536	-	-	70	-	-
GORGAS	Common 8-10 - Replace Scrubber Stack Mercury Monitor Umbilicals	111718	-	-	100	-	-
GORGAS	Common 8-10 - Scrubber Absorber Sump Pump	111732	-	-	-	-	100
GORGAS	Common 8-10 - Scrubber Booster Fans	111733	-	-	-	-	50
GORGAS	Common 8-10 - Scrubber Duct Expansion Joints	111737	-	50	1,400	50	-
GORGAS	Common 8-10 - Scrubber Inlet Joint	111738	-	-	-	-	100
GORGAS	Common 8-10 - Gypsum Dry Stacking Transfer Pumps	111744	-	-	-	-	50
GORGAS	Common 8-10 - Scrubber Controls Retrofit	111747	-	1,500	2,000	150	-
GORGAS	Common 8-10 - 5000 Baghouse Bag Replacement	111757	-	50	2,150	25	-
GORGAS	Common 8-10 - 5100 Baghouse Bag Replacement	111758	-	50	2,150	25	-
GORGAS	Common 8-10 - Byproduct Silo Filter Collector Bag Replacement	111768	-	-	175	-	-
GORGAS	Common 8-10 - Byproduct Silo Fluidizing Media Replacement	111769	-	-	320	-	-
GORGAS	Common 8-10 - Scrubber HMI Replacement	111787	-	-	400	100	-
GORGAS	Common 8-10 - Scrubber Station Service Batteries	113525	250	-	-	-	-
GORGAS	Common 8-10 - Dry Ash CCR	11178A	6,117	6,826	1,141	547	-
GORGAS	Common 8-10 - Waste Water Management	11178W	1,113	1,678	877	349	-
GORGAS	Unit 10 - Dry Bottom Ash	1117BA	24,647	723	-	-	-
GORGAS	Unit 10 - Gorgas Waste Water Management	1117CR	319	-	-	-	-
GORGAS	Unit 10 - ELG Waste Water Management - Scrubber	1117EG	2,762	23,939	55,667	72,247	24,008
GORGAS	Unit 10 - Waste Water NPDES	1117NP	681	-	-	-	-
GORGAS	Unit 10 - Dry Fly Ash	1117FA	2,173	1,513	-	-	-
GORGAS	Unit 10 - Intake Screens	1117TS	-	-	-	2,691	2,742
	Total Gorgas		47,987	37,374	79,525	76,684	27,400
	Gorgas NOx Projects (SCRs)		7,500	100	7,750	50	-
	Gorgas SO2 Projects (Scrubbers)		250	1,550	3,800	300	250
	Gorgas CCR-WATER		319	-	-	-	-
	Gorgas CCR-LAND		34,050	10,740	2,018	896	50
	Gorgas MATS		-	100	4,895	50	-
	Gorgas Particulate Matter (PM)		1,900	100	-	-	-
	Gorgas Effluent Guidelines/NPDES		3,768	24,764	60,992	72,697	24,358
	Gorgas CEMS Projects		200	20	-	-	-
	Gorgas Cooling Tower/Intake Structure		-	-	-	2,691	2,742
	Gorgas Sewage Treatment		-	-	70	-	-

Totals may not sum due to rounding

Total Plant Gorgas CCR Expenditures (Including Cost of Removal by Closure in Place)

		2019	2020	2021	2022	2023
Gorgas	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	34,369	10,740	2,018	896	50
Gorgas	Cost of Removal (Closure in Place) for CCR (Not included in above dollars)	91,994	95,360	100,018	102,392	104,843
	Gorgas Total CCR	126,363	106,100	102,036	103,288	104,893

Totals may not sum due to rounding

Table 3(e) – Plant Greene Co. Environmental Capital Expenditures for 2019–2023

(in thousands)

Official 2019 Capital Budget

	DESCRIPTION	PE	2019	2020	2021	2022	2023
GREENE CO	Intake Screens	1299TS	-	-	-	2,889	2,916
	Total Greene Co		-	-	-	2,889	2,916
	Greene Co Cooling Tower/Intake Structure		-	-	-	2,889	2,916

Totals may not sum due to rounding

Total Plant Greene Co. CCR Expenditures (Including Cost of Removal by Closure in Place)

	DESCRIPTION	2019	2020	2021	2022	2023
Greene	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	-	-	-	-	-
Greene	Cost of Removal (Closure in Place) for CCR (Not included in above dollars)	12,917	13,220	13,527	13,849	14,183
	Greene Total CCR	12,917	13,220	13,527	13,849	14,183

Totals may not sum due to rounding

Table 3(f) – Plant Miller Environmental Capital Expenditures for 2019–2023
(in thousands)

Official 2019 Capital Budget

	DESCRIPTION	PE	2019	2020	2021	2022	2023
MILLER	Unit 1 - Install Clean Air Catalyst	131403	1,056	1,607	1,056	1,607	1,056
MILLER	Unit 1 - Replace Popcorn Ash Screens	131407	-	230	-	-	-
MILLER	Unit 1 - Booster Fan A Blade Replacement	131410	-	-	-	344	-
MILLER	Unit 1 - Booster Fan B Blade Replacement	131411	-	-	-	344	-
MILLER	Unit 1 - Booster Fan Hub Replacement (A&B)	131420	-	-	-	1,148	-
MILLER	Unit 1 - Replace Fly Ash Seg Valve	131424	-	220	-	-	-
MILLER	Unit 1 - Replace Absorber Mist Eliminators	131429	-	1,929	-	-	-
MILLER	Unit 1 - Replace Clinker Grinders	131431	-	-	-	551	-
MILLER	Unit 1 - Replace Hopper ISO Gates	131432	-	-	-	129	-
MILLER	Unit 1 - Replace Unit Seg Valves	131433	-	-	28	28	28
MILLER	Unit 2 - Replace Screw Feeder	131434	-	-	-	37	-
MILLER	Unit 2 - Replace Dust Suppression Compressor	131435	-	64	-	-	-
MILLER	Unit 1 - Install SCR Air Cannon Systems	131436	-	1,378	-	-	-
MILLER	Unit 1 - Replace Dry ash Transfer Vessel	136502	-	-	-	321	-
MILLER	Unit 2 - Replace Dry Ash Transfer Vessel	139802	-	-	321	-	-
MILLER	Unit 2 - Booster Fan B Blade Replacement	141811	-	-	-	344	-
MILLER	Unit 2 - Booster Fan Hub Replacement (A&B)	141819	-	-	-	1,148	-
MILLER	Unit 2 - Replace Clinker Grinders	141826	-	-	-	551	-
MILLER	Unit 2 - Replace Hopper ISO Gates	141827	-	-	-	129	-
MILLER	Unit 2 - Replace Unit Seg Valves	141828	-	-	28	28	28
MILLER	Unit 2 - Replace Screw Feeder	141829	-	-	-	37	-
MILLER	Unit 2 - Replace Dust Suppression Compressor	141830	-	-	64	-	-
MILLER	Unit 2 - Replace Fly Ash Seg Valves & Install Limit Switches	141831	-	138	-	-	-
MILLER	Unit 2 - Replace Fly Ash Line From U2 To Silos	141833	459	-	-	-	-
MILLER	Unit 2 - Install SCR Catalyst	143701	1,056	1,607	1,056	1,607	1,056
MILLER	Unit 2 - Replace Popcorn Ash Screens	143702	-	689	-	-	-
MILLER	Units 1&2 - Replace FGD Inlet Cems Umbilical	145211	-	-	-	101	-
MILLER	Units 1&2 - Replace FGD Stack Cems Umbilical	145212	-	-	-	138	-
MILLER	Units 1&2 - Replace FGD DGA Monitors On Transformers	145215	-	138	-	-	-
MILLER	Common 1-4 - Gypsum Dewatering System Main Filter Belt B Replacement	150317	221	-	-	-	-
MILLER	Common 1-4 - Replace Dry Load Out Spout	150354	10	-	-	-	5
MILLER	Common 1-4 - Replace Scavenger Air Fans	150355	-	-	5	-	5
MILLER	Common 1-4 - Replace Silo Booster Pumps	150356	-	29	-	-	29
MILLER	Common 1-4 - Replace Silo Seg Valves	150357	-	-	-	29	29
MILLER	Unit 1 - Dry Bottom Ash CCR	1503B1	8	-	-	-	-
MILLER	Unit 2 - Dry Bottom Ash CCR	1503B2	10	-	-	-	-
MILLER	Common 1-4 - Dry Bottom Ash CCR	1503BA	2,270	-	-	-	-
MILLER	Common 1-4 - Close Cycle Cooling (CCC) Monitor	1503CC	-	-	-	-	242
MILLER	Common 1-4 - ELG Waste Water Management	1503CR	34,624	-	-	-	-
MILLER	Common 1-4 - ELG Waste Water Management - Scrubber	1503EG	33,019	-	-	-	-
MILLER	Common 1-4 - Landfill Phase 1	1503LF	-	928	29,625	30,188	30,762
MILLER	Common 1-4 - Install Biological WTP	1503SE	62,730	-	-	-	-
MILLER	Common 1-4 - Replace Ash Booster Station Switchgear	150404	96	719	-	-	-
MILLER	Unit 3 - Install Mercury Monitor	157515	400	-	-	-	-
MILLER	Unit 3 - Booster Fan A Blade Replacement	157516	-	-	-	-	375
MILLER	Unit 3 - Booster Fan B Blade Replacement	157517	-	-	-	-	375
MILLER	Unit 3 - Booster Fan Hub Replacement (A&B)	157521	-	-	-	-	1,250
MILLER	Unit 3 - Replace SCR Expansion Joints	157528	800	-	-	-	-
MILLER	Unit 3 - Replace SCR FGAS Shelter	157529	-	-	-	-	1,500
MILLER	Unit 3 - Precipitator Rewire	157530	-	-	-	-	750
MILLER	Unit 3 - Absorber Mist Eliminators	157531	2,300	-	-	-	-
MILLER	Unit 3 - Replace Hopper ISO Gates	157533	-	-	140	-	-
MILLER	Unit 3 - Replace Screw Feeders	157534	-	-	40	-	-
MILLER	Unit 3 - Replace Unit Seg Valves	157535	-	30	30	30	30
MILLER	Unit 3 - Replace Clinker Grinders	157536	-	-	600	-	-
MILLER	Unit 3 - Replace Fly Ash Seg Valves & Install Limit Switches	157538	-	-	240	-	-
MILLER	Unit 3 - Replace Dry Bottom Ash Transport Line	157539	-	-	-	200	-
MILLER	Unit 3 - Replace SCR Catalyst	159501	1,750	1,150	1,750	1,150	1,750
MILLER	Unit 3 - SCR Sonic Horn Installation	159502	1,500	-	-	-	-
MILLER	Unit 3 - Popcorn Ash Screen Replacement	161301	-	-	750	-	-
MILLER	Unit 4 - Replace SCR Catalyst	164503	1,750	1,150	1,750	1,150	1,750
MILLER	Unit 4 - Replace Popcorn Ash Screens	164504	-	-	750	-	-
MILLER	Unit 4 - Install Mercury Monitor	164515	400	-	-	-	-
MILLER	Unit 4 - Booster Fan B blade Replacement	164517	-	-	-	-	375
MILLER	Unit 4 - Booster Fan Hub Replacement (A&B)	164522	-	-	-	-	1,250
MILLER	Unit 4 - Replace SCR Expansion Joints	164528	800	-	-	-	-
MILLER	Unit 4 - Replace SCR FGAS Shelter	164529	-	-	-	-	1,500
MILLER	Unit 4 - Absorber Mist Eliminators	164532	2,100	-	-	-	-
MILLER	Unit 4 - Replace Seg Valves	164534	-	30	30	30	30
MILLER	Unit 4 - Replace Clinker Grinders	164536	-	-	600	-	-
MILLER	Unit 4 - Replace Hopper Iso Gates (2)	164537	-	-	140	-	-
MILLER	Unit 4 - Replace Screw Feeder	164538	-	-	40	-	-
MILLER	Unit 4 - Replace Fly Ash Seg Valves & Install Limit Switches	164539	-	-	240	-	-
MILLER	Unit 4 - Replace Dry Bottom Ash Transport Line	164540	-	-	-	-	200
MILLER	Unit 4 - Install SCR Air Cannons	166602	1,500	-	-	-	-

Totals may not sum due to rounding

Table 3(f) – Plant Miller Environmental Capital Expenditures for 2019–2023 (continued)

(in thousands)

Official 2019 Capital Budget

	DESCRIPTION	PE	2019	2020	2021	2022	2023
MILLER	Units 3&4 - Replace FGD Inlet Cems Umbilical	170210	-	-	110	-	-
MILLER	Units 3&4 - Replace FGD Stack Cems Umbilical	170211	-	-	150	-	-
MILLER	Units 3&4 - Replace FGD DGA Monitors On Transformers	170214	-	150	-	-	-
MILLER	Units 3&4 - Dry Ash Transfer Vessel	174903	-	-	-	-	350
MILLER	**Units 3&4 - Replace Fly Ash Air Compressor**	**174910**	-	**350**	-	-	-
	Total Miller		**148,859**	**12,535**	**39,543**	**41,368**	**44,723**
	Miller NOx Projects (SCRs)		**10,212**	**7,810**	**7,112**	**5,514**	**8,612**
	Miller SO2 Projects (Scrubbers)		**4,621**	**2,216**	-	**3,329**	**3,625**
	Miller CCR-LAND		**2,854**	**2,444**	**30,585**	**30,862**	**31,144**
	Miller CCR-WATER		**34,624**	-	-	-	-
	Miller MATS		**800**	-	-	-	-
	Miller Particulate Matter (PM)		-	**64**	**386**	**321**	**1,100**
	Miller CEMS Projects		-	-	**260**	**239**	-
	Miller Effluent Guidelines/NPDES		**95,748**	-	**1,200**	**1,102**	-
	Miller Cooling Tower/Intake Structure		-	-	-	-	**242**

Totals may not sum due to rounding

Total Plant Miller CCR Expenditures (Including Cost of Removal by Closure in Place)

		2019	2020	2021	2022	2023
Miller	**Capital Expenditures for CCR** **(Included in above amounts for CCR-Water and CCR-Land)**	37,478	2,444	30,585	30,862	31,144
Miller	**Cost of Removal (Closure in Place) for CCR** **(Not included in above dollars)**	67,969	69,566	71,179	72,876	74,633
	Miller Total CCR	105,447	72,010	101,764	103,739	105,777

Totals may not sum due to rounding

Table 4 – Other Generation Environmental Capital Expenditures for 2019–2023

(in thousands)

Official 2019 Capital Budget

	DESCRIPTION	PE	2019	2020	2021	2022	2023
WASHINGTON CO	Package Boiler 201 CEMS	182307	130	-	-	-	-
WASHINGTON CO	Cooling Tower Media Replacement	182401	-	-	-	300	-
WASHINGTON CO	Cooling Tower Drift Eliminator Media Replacement	182406	-	100	-	-	-
WASHINGTON CO	Cooling Tower Integrity	182412	400	400	400	400	400
THEODORE	Replace SCR Catalyst	182901	-	250	1,250	-	-
THEODORE	HRSG & PB CEMS Replacement	183210	-	-	300	-	-
THEODORE	Cooling Tower Structural Strengthening	183231	110	-	-	-	-
THEODORE	Cooling Tower Integrity	183232	250	250	250	250	260
BARRY CC	Unit 6 - Cooling Tower Integrity	185602	480	470	470	475	500
BARRY CC	Unit 6 - Replace SCR Catalyst	186801	1,500	-	-	-	-
BARRY CC	Unit 7 - Replace SCR Catalyst	186802	1,500	-	-	-	-
BARRY CC	Units 6&7 - Replace SCR Catalyst	186804	-	150	-	-	-
BARRY CC	Unit 7 - Cooling Tower Acid Tank	186805	-	150	-	-	-
BARRY CC	Units 6&7 - Mercury Monitor Replacement	186817	50	-	-	-	-
BARRY CC	Units 6&7 - Lagoon Addition	186824	125	-	-	-	-
BARRY CC	Unit 6 - Cooling Tower Drift Eliminator Media Replacement	187146	-	-	-	-	250
BARRY CC	Unit 6 - Cooling Tower Fans	187139	-	-	-	-	125
BARRY CC	Unit 7 - Cooling Tower Fans	187140	-	-	-	-	125
BARRY CC	Unit 6 - Cooling Tower Media Replacement	187135	1,500	-	-	-	-
BARRY CC	Unit 6 - 6F Cooling Tower Gearbox	187186	100	800	80	80	80
BARRY CC	Unit 7 - 7E Cooling Tower Gearbox	187187	100	800	80	80	80
BARRY CC	Units 6&7 - Waste Water Management	1868CR	580	-	-	-	-
BARRY CC	Unit 6 - Replace CEMS Monitoring Equipment	187109	310	-	-	-	-
BARRY CC	Unit 7 - Cooling Tower Media Replacement	187136	1,500	-	-	-	-
BARRY CC	Unit 7 - Replace CEMS Monitoring Equipment	187110	310	-	-	-	-
	Total Other		8,945	3,370	2,830	1,585	1,820
	Other NOx Projects (SCRs)		3,000	400	1,250	-	-
	Other CCR-WATER		580	-	-	-	-
	Other CCR-LAND		125	-	-	-	-
	Other Effluent Guidelines/NPDES		-	-	-	-	-
	Other CEMS Projects		750	-	300	-	-
	Other MATS		50	-	-	-	-
	Other Cooling Tower/Intake Structure		4,440	2,970	1,280	1,585	1,820

Totals may not sum due to rounding

Total Other CCR Expenditures (Including Cost of Removal by Closure in Place)

		2019	2020	2021	2022	2023
Other	Capital Expenditures for CCR (Included in above amounts for CCR-Water and CCR-Land)	705	-	-	-	-
Other	Cost of Removal (Closure in Place) for CCR (Not included in above dollars)	-	-	-	-	-
	Other Total CCR	705	-	-	-	-

Totals may not sum due to rounding

Table 5 – Hydro Generation Environmental Capital Expenditures for 2019–2023

(in thousands)

Official 2019 Capital Budget

	DESCRIPTION	PE	2019	2020	2021	2022	2023
HYDRO	Coosa System - Adaptive Mgmt Plan for Habitat of Endangered Species	259202	-	350	500	-	-
	Total Hydro		-	350	500	-	-
	Hydro Aeration and Minimum Flow Projects		-	350	500	-	-

Totals may not sum due to rounding

ESTIMATED ENVIRONMENTAL CAPITAL EXPENDITURES FOR 2019 – 2023

POWER DELIVERY

Table 6 – Summary of Power Delivery Environmental Capital Expenditures for 2019–2023
(in thousands)

Official 2019 Capital Budget

	DESCRIPTION	2019	2020	2021	2022	2023
POWER DELIVERY	230 KV Transmission Line	1,087				
	Total Power Delivery Projects	1,087	-	-	-	-

Totals may not sum due to rounding

Table 7 – Power Delivery Capital Expenditures for 2019–2023

(in thousands)

Official 2019 Capital Budget

	DESCRIPTION	PE	DISP	2019	2020	2021	2022	2023
POWER DELIVERY	Raise Gaston - Goat Rock (#1) 230kVTL	44522A	T230E	304				
POWER DELIVERY	Raise Gaston - Goat Rock (#2) 230kVTL	44522B	T230E	347				
POWER DELIVERY	Raise Gaston - Fayetteville DS 230kVTL	44522C	T230E	436				
	Total Power Delivery Projects			1,087	-	-	-	-

Totals may not sum due to rounding

ESTIMATED ENVIRONMENTAL O&M EXPENSE FOR 2019–2023

Table 8 – Environmental O&M Expense for 2019–2023

2019 O&M Budget and Forecast

Activity	Environmental Activities	2019	2020	2021	2022	2023
E316A	316A REGULATION	164,327	169,256	174,334	179,564	184,951
E316B	316B REGULATION	693,049	713,840	735,255	757,313	780,033
EDISP	ENVIRO DISPOSAL ACTIVITY-ENVIRO AFFAIRS COMPLIANCE	204,369	210,499	216,815	223,318	230,019
EHYDR1	COOSA/WARRIOR/TALLAPOOSA SHORELINE STUDIES, ESA STUDIES	465,000	478,950	493,319	508,118	523,362
EHYDR11	ENVIRO FISH CULTURE FACILITY	564,057	580,979	598,408	616,360	634,851
EHYDR12	ENVIRO FISHERIES HABITAT ENHANCEMENT	423,043	435,734	448,806	462,271	476,139
EHYDR9	ENVIRO WILDLIFE HABITAT ENHANCEMENT&RESTORATION	1,129,186	1,163,062	1,197,953	1,233,892	1,270,909
EMERC	ENVIRONMENTAL MERCURY RATA TESTING	1,920,857	1,978,481	2,037,837	2,098,973	2,161,942
F34	COMPLIANCE-ENVIRONMENTAL	35,113,360	34,637,089	39,256,360	38,077,579	41,856,712
F8A	ASH SALES	(2,876,744)	(2,876,744)	(2,876,744)	(2,876,744)	(2,876,744)
F8E	OTHER ENVIRONMENTAL	0	0	2,508,000	2,508,000	0
F8G	GYPSUM SALES	(489,192)	(489,192)	(489,192)	(489,192)	(489,192)
FAA	ASH SLUICE	378,884	384,473	534,602	462,715	460,464
FAAE	ASH SLUICE-ENVIRONMENTAL	220,696	253,293	259,359	268,078	615,562
FAB	BOTTOM ASH	5,250,989	5,965,593	6,870,747	6,318,782	6,609,249
FAC	FLY ASH	3,597,622	3,535,676	3,805,437	3,709,467	4,421,826
FAD	NPDES TREATMENT	3,787,285	1,789,690	1,832,701	1,836,405	1,840,969
FAE	ASH DISPOSAL	3,814,154	3,903,284	4,576,341	4,076,630	4,158,077
FAF	PRECIPITATOR	3,107,930	2,779,441	4,193,524	3,428,075	4,805,322
FAFE	PRECIP. FLUE GAS CONDITIONING	0	0	0	0	211,069
FAG	BAG HOUSE	933,978	938,819	1,699,450	957,549	964,752
FAGA	BAGHOUSE SYSTEM	70,176	72,276	74,448	76,683	78,984
FAGE	BYPRODUCT HANDLING	49,120	50,592	52,112	53,676	55,284
FAGP	SERVICE FACILITIES (SUPPORT)	18,360	18,912	19,476	20,064	20,664
FAGS	SERVICE/CONTROL AIR SYSTEMS	67,344	69,364	71,444	73,588	75,796
FAY	ASH HANDLING SYSTEM	300,581	307,693	318,777	328,501	336,091
FBF	STACK	601,451	198,681	263,147	240,053	205,234
FBH	CEMS-ALL ASSOC. DEVICES	3,288,831	3,371,238	3,475,002	3,546,650	3,637,547
FBK	EMISSION CONTROL CHEMICAL INJECTION	145,008	149,352	153,840	158,448	163,200
FBKA	ACTIVATED CARBON INJECTION (ACI)	2,836,100	3,717,360	3,596,291	3,012,866	3,010,251
FBKB	SULFURIC ACID MIST CONTROL (SAMC)	1,119,992	1,123,592	1,327,300	1,316,742	1,335,051
FBKC	DRY SORBENT INJECTION (DSI)	356,100	320,040	344,872	391,023	338,382
FBKE	BROMINE INJECTION	269,800	319,800	341,000	319,800	319,800
FBKG	CHEMICAL INJECTION FOR MERCURY	668,753	656,674	703,534	596,197	606,782
FDA	DUST SUPPRESSION	4,509,605	4,593,561	4,912,313	4,945,530	7,532,044
FHK	COOLING TOWERS	3,438,432	3,224,685	3,252,107	3,327,882	3,597,555
FNF	WASTE WATER	3,416,946	3,325,519	3,486,622	3,869,398	6,284,464
FNW	PLANT PROCESS WASTE WATER TREATMENT	7,341,641	7,388,299	7,517,653	7,649,601	7,784,238
FTE	ENVIRONMENTAL PROJECTS (HYDRO)	3,523,500	3,635,430	3,749,187	3,868,264	3,990,139
FVK	WATER/STEAM INJECTION SYSTEM	165,727	166,155	179,678	178,932	182,511
FXA	FLUE GAS HANDLING	2,246,650	1,697,482	2,155,326	1,246,736	1,276,386
FXB	LIMESTONE HANDLING	22,876,327	20,306,307	24,876,673	24,880,059	23,573,475
FXC	SCRUBBER VESSEL	6,829,569	6,879,624	9,456,141	6,989,203	7,341,408
FXD	GYPSUM HANDLING	3,496,914	3,569,930	3,645,034	3,720,107	3,794,674
FXE	RETURN WATER	117,840	121,375	125,015	128,767	131,811
FXF	MAKE-UP WATER	141,578	143,584	469,869	149,781	147,507
FXG	SUBSTATION/SWITCHYARD	4,942	5,090	5,243	5,401	5,563
FXJ	GAS COOLING/RECYCLE SPRAY	594,498	609,788	1,073,959	649,622	669,113
FXK	STATION SERVICE	35,000	35,000	173,667	68,180	70,225
FXL	GYPSUM DRAW-OFF	196,643	201,112	208,619	214,876	221,322
FXM	OXIDATION AIR	56,673	57,750	60,125	61,928	63,512
FXN	WATER TREATMENT	106,531	107,375	108,236	109,109	109,998
FXP	SERVICE FACILITIES-SCRUBBER SYS	422,872	450,087	488,529	461,934	475,669
FXR	FIRE PROTECTION-SCRUBBER SYS	58,378	59,568	61,297	62,271	63,828
FXS	AIR SYSTEM-SCRUBBER SYS	437,516	445,397	465,681	452,858	397,958
FXW	WASTE WATER TREATMENT	6,949,638	910,975	912,387	913,826	625,625
FXY	SCRUBBER SYSTEM	4,743,445	11,741,274	5,768,401	5,103,720	17,166,250
FYA	AMMONIA UNLOADING/STORAGE AREA	7,987,937	8,122,391	8,320,705	8,334,039	8,531,631
FYB	AMMONIA FORWARDING SYSTEM	62,320	63,163	155,374	65,586	66,884
FYC	AMMONIA VAPORIZATION SKID	92,025	93,253	94,737	94,710	95,310
FYD	AMMONIA INJECTION GRID	59,208	110,208	134,208	107,358	210,093
FYE	REACTOR BOXES	1,288,917	1,228,844	1,580,373	1,260,059	1,347,928
FYF	AUXILIARY SYSTEMS	376,294	379,806	391,589	397,205	399,265
FYH	SNCR	574,259	399,800	418,340	541,069	438,365
FYP	SERVICE FACILITIES	25,500	26,010	26,530	27,061	27,602
FYY	SELECTIVE CATALYTIC REDUCTION	1,676,220	1,690,112	954,606	968,706	982,287
	Grand Total	152,048,009	148,716,750	164,042,778	155,345,223	176,627,978

Totals may not sum due to rounding

ENVIRONMENTAL CAPITAL PLACED IN SERVICE FOR 2019

GENERATION & POWER DELIVERY

Table 9 – Environmental Generation & Power Delivery Capital Placed In Service for 2019

Alabama Power Company
2019 Environmental Projects Placed In Service
Generation and Power Delivery

Plant	Project	PE	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019 Total
Barry CC	UNIT 6 REPLACE SCR CATALYST	APC-1868				1,593,534									1,593,534
Barry CC	UNIT 7 REPLACE SCR CATALYST	APC-1868											1,593,534		1,593,534
Barry CC	UNITS 6&7 MERCURY MONITOR REPLACEMENT	APC-1868					50,000								50,000
Barry CC	LAGOON ADDITION	APC-1868												125,000	125,000
Barry CC	UNITS 6&7 WASTE WATER MANAGEMENT	APC-1868		580,000											580,000
Barry CC	UNIT 6 REPLACE CEMS MONITORING EQUIP	APC-1871				310,000									310,000
Barry CC	UNIT 7 REPLACE CEMS MONITORING EQUIP	APC-1871			310,000										310,000
Barry CC	UNIT 6 COOLING TOWER MEDIA REPLACEMENT	APC-1871												1,500,000	1,500,000
Barry CC	UNIT 7 COOLING TOWER MEDIA REPLACMENT	APC-1871											1,500,000		1,500,000
Barry CC	UNIT 6 COOLING TOWER GEARBOX	APC-1871						25,000	25,000	25,000	25,000				100,000
Barry CC	UNIT 7 COOLING TOWER GEARBOX	APC-1871						25,000	25,000	25,000	25,000				100,000
Barry CC		**Sub-Total Barry CC**		**580,000**	**310,000**	**1,903,534**	**50,000**	**50,000**	**50,000**	**50,000**	**50,000**		**3,093,534**	**1,625,000**	**7,762,068**
Barry Steam	UNIT 1 REPLACE CEMS EQUIPMENT	APC-0115					100,000								100,000
Barry Steam	UNIT 4 PRECIPITATOR WASH SYSTEM	APC-0283												500,000	500,000
Barry Steam	UNIT 4 PRECIPITATOR REPLACEMENT PROJECT	APC-0345	609,000	609,000	609,000	609,000	575,000	575,000	575,000	575,000	4,557,000	5,557,000	7,136,000	3,985,000	25,971,000
Barry Steam	UNIT 5 REPLACE PRECIPITATOR RAPPERS (A&B)	APC-0354	1,279,000												1,279,000
Barry Steam	UNIT 5 PRECIPITATOR ELEVATOR	APC-0354			1,050,660	150,000									1,200,660
Barry Steam	UNIT 5 PRECIPITATOR HOPPER HEATERS	APC-0354				4,952,256									4,952,256
Barry Steam	UNIT 5 AIR COMPRESSOR REPLACEMENT	APC-0399				125,000									125,000
Barry Steam	UNIT 5 SCRUBBER OX AIR BLOWER	APC-0399											250,000		250,000
Barry Steam	UNIT 5 SCR VACUUM SYSTEM	APC-0399											100,000		100,000
Barry Steam	UNIT 5 SCR FLUE GAS FANS	APC-0399											350,000		350,000
Barry Steam	UNITS 1-5 MERCURY MONITOR REPLACEMENT	APC-0445												50,000	50,000
Barry Steam	LAGOON ADDITION	APC-0461												125,000	125,000
Barry Steam	UNITS 4&5 FLY ASH TRANSPORT AREA HOIST	APC-0468					200,000								200,000
Barry Steam	ASH HANDLING	APC-0474	124,950	124,950	7,220,768	124,950	124,950	124,950	124,950	124,950	124,950	124,950	124,950	125,550	8,595,818
Barry Steam	COMMON DRY BOTTOM ASH	APC-0474	4,864,000	2,333,000	313,000	128,000	90,000	60,000							7,788,000
Barry Steam	UNITS 1-5 WASTE WATER MANAGEMENT	APC-0474	2,560,000		494,000	379,000	138,000	71,000							3,642,000
Barry Steam	UNIT 5 ELG SCRUBBER RETURN WATER	APC-0474												1,400,000	1,400,000
Barry Steam		**Sub-Total Barry Steam Plant**	**9,436,950**	**3,066,950**	**9,687,428**	**6,468,206**	**1,227,950**	**830,950**	**699,950**	**699,950**	**4,681,950**	**5,681,950**	**7,960,950**	**6,185,550**	**56,628,734**
Gadsden Steam	UNITS 1&2 REPLACE PUMP	APC-0646												100,000	100,000
Gadsden Steam		**Sub-Total Gadsden Steam Plant**												**100,000**	**100,000**
Gaston Steam	UNIT 5 BOTTOM ASH SYSTEM VALVES	APC-0662									220,000				220,000
Gaston Steam	UNIT 5 REPLACE SCR CATALYST	APC-0699											1,564,524		1,564,524
Gaston Steam	UNIT 5 SCRUBBER LIMESTONE BLOWERS	APC-0699												1,365,477	1,365,477
Gaston Steam	UNIT 5 SCRUBBER GAS COOLING HEADER PIPING	APC-0699									385,000				385,000
Gaston Steam	UNIT 5 DRY BOTTOM ASH	APC-0699	924,000	924,000	50,000	50,000	50,000	50,000							2,048,000
Gaston Steam	UNIT 5 FLY ASH SYSTEM VALVES	APC-0706						110,000							110,000
Gaston Steam	UNIT 5 PRECIPITATOR DUST VALVE ISO GATES	APC-0706											985,230		985,230
Gaston Steam	UNIT 5 FLY ASH HANDLING BLOWER	APC-0706									110,000				110,000
Gaston Steam	UNIT 5 GYPSUM TRANSFER PUMPS	APC-0755									220,000				220,000
Gaston Steam	UNITS 1-5 WASTE WATER MANAGEMENT	APC-0835	296,000	296,000	50,000	50,000	50,000	50,000							792,000
Gaston Steam		**Sub-Total Gaston Steam Plant**	**1,220,000**	**1,220,000**	**100,000**	**100,000**	**100,000**	**210,000**			**935,000**		**2,549,754**	**1,365,477**	**7,800,231**
Gorgas Steam	UNIT 8 CEMS	APC-0969												150,000	150,000
Gorgas Steam	UNIT 9 CEMS	APC-1014												200,000	200,000
Gorgas Steam	UNIT 10 PRECIPITATOR BOX REPLACEMENT	APC-1073												1,900,000	1,900,000
Gorgas Steam	UNIT 10 REPLACE SCR CATALYST	APC-1089												7,500,000	7,500,000
Gorgas Steam	UNIT 10 CLINKER GRINDERS	APC-1109												325,000	325,000
Gorgas Steam	WASTE WATER MANAGEMENT	APC-1117	106,000	106,500	106,500										319,000
Gorgas Steam	NPDES LOW VOLUME WASTE WATER	APC-1117												681,000	681,000
Gorgas Steam	SCRUBBER STATION SERVICE BATTERIES	APC-1135												350,000	350,000
Gorgas Steam		**Sub-Total Gorgas Steam Plant**	**106,000**	**106,500**	**106,500**									**11,106,000**	**11,425,000**

Totals may not sum due to rounding.

Table 9 – Environmental Generation & Power Delivery Capital Placed In Service for 2019

Alabama Power Company
2019 Environmental Projects Placed In Service
Generation and Power Delivery

Plant	Project	PE	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019 Total
Miller Steam	UNIT 2 REPLACE FLY ASH LINE TO SILOS	APC-1418							459,200						459,200
Miller Steam	UNIT 2 REPLACE SCR CATALYST	APC-1437							243,375	785,232	6,887	6,887	6,888	6,889	1,056,158
Miller Steam	UNITS 1-4 GYPSUM DEWATERING MAIN FILTER BELT B	APC-1503								278,491	55,154				333,645
Miller Steam	UNITS 1-4 REPLACE DRY LOAD OUT SPOUT	APC-1503								7,194	2,398				9,592
Miller Steam	UNIT 1 DRY BOTTOM ASH	APC-1503	3,674	3,674	918										8,266
Miller Steam	UNIT 2 DRY BOTTOM ASH	APC-1503	4,592	4,592	918										10,102
Miller Steam	UNITS 1-4 DRY BOTTOM ASH	APC-1503	1,230,654	1,039,772											2,270,426
Miller Steam	UNITS 1-4 WASTE WATER MANAGEMENT	APC-1503							185,882,600						185,882,600
Miller Steam	UNITS 1-4 ELG WASTER WATER MANAGEMENT	APC-1503							118,447,509						118,447,509
Miller Steam	UNITS 1-4 BIOLOGICAL TREATMENT SYSTEM	APC-1503									88,225,768				88,225,768
Miller Steam	UNIT 3 REPLACE FGD VIBRATION MONITORING	APC-1575				429,081	100,000	20,000							549,081
Miller Steam	UNIT 3 REPLACE SCR EXPANSION JOINT	APC-1575				560,000	200,000	40,000							800,000
Miller Steam	UNIT 3 REPLACE ABSORBER MIST ELIMINATORS	APC-1575				1,610,000	575,000	115,000							2,300,000
Miller Steam	UNIT 3 REPLACE SCR CATALYST	APC-1595				1,427,648	437,500	87,500							1,952,648
Miller Steam	UNIT 3 INSTALL SCR AIR CANNONS	APC-1595							1,500,000						1,500,000
Miller Steam	UNIT 4 REPLACE SCR CATALYST	APC-1645					1,863,817	87,500							1,951,317
Miller Steam	UNIT 4 INSTALL FGD VIBRATION MONITORING	APC-1645				356,404	100,000	20,000							476,404
Miller Steam	UNIT 4 REPLACE SCR EXPANSION JOINTS	APC-1645				560,000	200,000	40,000							800,000
Miller Steam	UNIT 4 REPLACE ABSORBER MIST ELIMINATORS	APC-1645				1,520,000	525,000	105,000							2,150,000
Miller Steam	UNIT 4 INSTALL SCR AIR CANNONS	APC-1666							1,500,000						1,500,000
Miller Steam	Sub-Total Miller Steam Plant		1,238,920	1,048,038	1,836	6,463,133	4,001,317	515,000	308,032,684	1,070,917	88,290,207	6,887	6,888	6,889	410,682,716
Theodore Co-Gen	COOLING TOWER STRUCTURAL STRENGTHENING	APC-1832							110,005						110,005
Theodore Co-Gen	COOLING TOWER INTEGRITY	APC-1832												250,000	250,000
Theodore Co-Gen	Sub-Total Theodore Co-Gen								110,005					250,000	360,005
Washington Co. Co-Gen	CEMS FOR PACKAGE BOILER	APC-1823			130,000										130,000
Washington Co. Co-Gen	COOLING TOWER INTEGRITY	APC-1824												400,000	400,000
Washington Co. Co-Gen	Sub-Total Washington Co. Co-Gen				130,000									400,000	530,000
	Total Generation Placed In Service		12,001,870	6,021,488	10,335,764	14,934,873	5,379,267	1,605,950	308,892,639	1,820,867	93,957,157	5,688,837	13,611,126	21,038,916	495,288,753
	Total Generation Retirements		(5,510,200)		(39,000)	(37,500)	(4,755,000)	(515,760)	(405,000)		(197,878)	(156,185)	(330,000)	(9,240,000)	(21,186,522)
	Generation Cumulative Plant In Service 2019 Budget Process		**5,110,397,132**	**5,116,418,620**	**5,126,715,384**	**5,141,612,757**	**5,142,237,024**	**5,143,327,214**	**5,451,814,853**	**5,453,635,720**	**5,547,394,999**	**5,552,927,652**	**5,566,208,778**	**5,578,007,694**	

Plant	Project	PE	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019 Total
Power Delivery	RAISE GASTON - GOAT ROCK (#1) 230KV TL	APC-4452					364,279	804							365,083
Power Delivery	RAISE GASTON - GOAT ROCK (#2) 230KV TL	APC-4452					383,908	920							384,828
Power Delivery	RAISE GASTON - FAYETTEVILLE DS 230KV TL	APC-4452					466,111	1,153							467,264
	Total Power Delivery Placed In Service						1,214,298	2,877							1,217,175
	Power Delivery Cumulative Plant In Service 2019 Budget Process		**34,983,471**	**34,983,471**	**34,983,471**	**34,983,471**	**36,197,769**	**36,200,646**	**36,200,646**	**36,200,646**	**36,200,646**	**36,200,646**	**36,200,646**	**36,200,646**	
	Total Cumulative Plant In Service 2019 Budget Process		**5,145,380,603**	**5,151,402,091**	**5,161,698,855**	**5,176,596,228**	**5,178,434,793**	**5,179,527,860**	**5,488,015,499**	**5,489,836,366**	**5,583,595,645**	**5,589,128,298**	**5,602,409,424**	**5,614,208,340**	

Totals may not sum due to rounding.

ENVIRONMENTAL O&M EXPENSE FOR 2019

Table 10 – Environmental O&M Expense for 2019

2019 O&M Budget and Forecast

Activity	Environmental Activities	2019
E316A	316A REGULATION	164,327
E316B	316B REGULATION	693,049
EDISP	ENVIRO DISPOSAL ACTIVITY-ENVIRO AFFAIRS COMPLIANCE	204,369
EHYDR1	COOSA/WARRIOR/TALLAPOOSA SHORELINE STUDIES, ESA STUDIES & CONS	465,000
EHYDR11	ENVIRO FISH CULTURE FACILITY	564,057
EHYDR12	ENVIRO FISHERIES HABITAT ENHANCEMENT	423,043
EHYDR9	ENVIRO WILDLIFE HABITAT ENHANCEMENT & RESTORATION	1,129,186
EMERC	ENVIRONMENTAL MERCURY RATA TESTING	1,920,857
F34	COMPLIANCE-ENVIRONMENTAL	35,113,358
F8A	ASH SALES	(2,876,744)
F8E	OTHER ENVIRONMENTAL	0
F8G	GYPSUM SALES	(489,192)
FAA	ASH SLUICE	378,884
FAAE	ASH SLUICE-ENVIRONMENTAL	220,696
FAB	BOTTOM ASH	5,250,989
FAC	FLY ASH	3,597,622
FAD	NPDES TREATMENT	3,787,285
FAE	ASH DISPOSAL	3,814,154
FAF	PRECIPITATOR	3,107,930
FAFE	PRECIP. FLUE GAS CONDITIONING	0
FAG	BAG HOUSE	933,978
FAGA	BAGHOUSE SYSTEM	70,176
FAGE	BYPRODUCT HANDLING	49,120
FAGP	SERVICE FACILITIES (SUPPORT)	18,360
FAGS	SERVICE/CONTROL AIR SYSTEMS	67,344
FAY	ASH HANDLING SYSTEM	300,581
FBF	STACK	601,451
FBH	CEMS-ALL ASSOC. DEVICES	3,288,831
FBK	EMISSION CONTROL CHEMICAL INJECTION	145,008
FBKA	ACTIVATED CARBON INJECTION (ACI)	2,836,100
FBKB	SULFURIC ACID MIST CONTROL (SAMC)	1,119,992
FBKC	DRY SORBENT INJECTION (DSI)	356,100
FBKE	BROMINE INJECTION	269,800
FBKG	CHEMICAL INJECTION FOR MERCURY	668,753
FDA	DUST SUPPRESSION	4,509,605
FHK	COOLING TOWERS	3,438,432
FNF	WASTE WATER	3,416,946
FNW	PLANT PROCESS WASTE WATER TREATMENT	7,341,641
FTE	ENVIRONMENTAL PROJECTS (HYDRO)	3,523,500
FVK	WATER/STEAM INJECTION SYSTEM	165,727
FXA	FLUE GAS HANDLING	2,246,650
FXB	LIMESTONE HANDLING	22,876,327
FXC	SCRUBBER VESSEL	6,829,569
FXD	GYPSUM HANDLING	3,496,914
FXE	RETURN WATER	117,840
FXF	MAKE-UP WATER	141,578
FXG	SUBSTATION/SWITCHYARD	4,942
FXJ	GAS COOLING/RECYCLE SPRAY	594,498
FXK	STATION SERVICE	35,000
FXL	GYPSUM DRAW-OFF	196,643
FXM	OXIDATION AIR	56,673
FXN	WATER TREATMENT	106,531
FXP	SERVICE FACILITIES-SCRUBBER SYS	422,872
FXR	FIRE PROTECTION-SCRUBBER SYS	58,378
FXS	AIR SYSTEM-SCRUBBER SYS	437,516
FXW	WASTE WATER TREATMENT	6,949,638
FXY	SCRUBBER SYSTEM	4,743,445
FYA	AMMONIA UNLOADING/STORAGE AREA	7,987,937
FYB	AMMONIA FORWARDING SYSTEM	62,320
FYC	AMMONIA VAPORIZATION SKID	92,025
FYD	AMMONIA INJECTION GRID	59,208
FYE	REACTOR BOXES	1,288,917
FYF	AUXILIARY SYSTEMS	376,294
FYH	SNCR	574,259
FYP	SERVICE FACILITIES	25,500
FYY	SELECTIVE CATALYTIC REDUCTION	1,676,220
Total		152,048,009

Totals may not sum due to rounding

APPENDIX A

ACRONYMS AND ABBREVIATIONS

ACE	Affordable Clean Energy
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
BATW	Bottom Ash Transport Water
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
CCR or CCRs	Coal Combustion Residuals
CEIP	Clean Energy Incentive Program

CEMS	Continuous Emissions Monitoring System
CMMS	Continuous Mercury Monitoring System
CFR	Code of Federal Regulations
CPP	Clean Power Plan
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COHPAC	Compact Hybrid Particulate Collector
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DOJ	Department of Justice
DRR	Data Requirement Rule
DSI	Dry Sorbent Injection
EGU	Electric Generating Unit
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPCRA	Emergency Planning and Community Right-to-Know Act
ESA	Endangered Species 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
HAT	Harris Action Team
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
NEPA	National Environmental Policy Act
NH3	Ammonia
NMFS	National Marine Fisheries Service
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NOI	Notice of Intent
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
PM2.5	Particulate Matter less than 2.5 micrometers in size

PM10	Particulate Matter less than 10 micrometers in size
PME	Protection Mitigation and Enhancement
PPB	Parts per billion
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
RHS	Rough Hornsnail
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
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
WOTUS	Waters of the United States