Implementation of the "Clean Smokestacks Act"

A Report to the Environmental Review Commission and the Joint Legislative Utility Review Committee

Submitted by the North Carolina Department of Environment and Natural Resources and the North Carolina Utilities Commission

Report No. IX

June 1, 2011

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This report is submitted pursuant to the requirement of Section 14 of Session Law 2002-4, Senate Bill 1078 enacted June 20, 2002. The actions taken to date by Progress Energy Carolinas, Inc. and Duke Energy Carolinas, LLC appear to be in accordance with the provisions and requirements of the Clean Smokestacks Act.

Dee A. Freeman

Signed: ______________________________

Dee A. Freeman, Secretary
Department of Environment and Natural Resources

Edward S. Finley, Jr

Signed: ______________________________

Edward S. Finley, Jr., Chairman
North Carolina Utilities Commission

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Executive Summary

The Clean Smokestacks Act or Act was enacted to improve air quality in North Carolina by imposing limits on the emission of certain pollutants from certain coal burning electric generating facilities and to provide for the recovery of costs associated with achieving compliance with those limits. In addition to imposing certain emissions limitations on the investor-owned electric utilities (IOUs) subject to its provisions, Duke Energy Carolinas, LLC (Duke Energy) and Progress Energy Carolinas, Inc. (Progress Energy), the Act also imposed certain specific requirements on the Department of Environment and Natural Resources (DENR); the Division of Air Quality (DAQ) of DENR; the Environmental Management Commission; the Department of Justice, effectively; and the Utilities Commission (Commission). The Act, among other things, requires DENR and the Commission to report annually on the implementation of the Act to the Environmental Review Commission and the Joint Legislative Utility Review Committee. The Act also requires the IOUs to submit annual reports to DENR and the Commission containing certain specified, pertinent information.

This report includes summaries of the IOUs' annual reports and certain actions and/or activities undertaken by the aforementioned state agencies in compliance with the Act. In summary, DENR and the Commission have concluded that the actions taken to date by Duke Energy and Progress Energy are in accordance with the provisions and requirements of the Clean Smokestacks Act. Further, the compliance plans and schedules proposed by Duke Energy and Progress Energy appear adequate to achieve the emissions limitations set out in G.S. 143-215.107D.

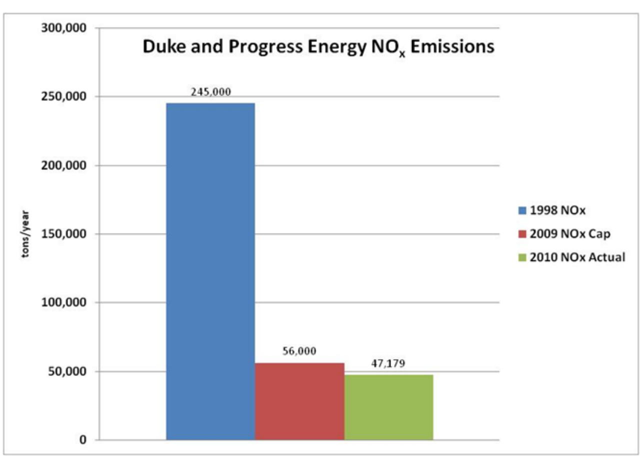
The General Assembly of North Carolina, Session 2001, passed Session Law 2002-4, also known as Senate Bill 1078. This legislation is titled "*An Act to Improve Air Quality in the State by Imposing Limits on the Emission of Certain Pollutants from Certain Facilities that Burn Coal to Generate Electricity and to Provide for Recovery by Electric Utilities of the Costs of Achieving Compliance with Those Limits*" ("the Clean Smokestacks Act" or "the Act"). The Clean Smokestacks Act, in Section 14, requires the Department of Environment and Natural Resources (DENR) and the Utilities Commission (Commission) to report annually, i.e., by June 1 of each year, on the implementation of the Act to the Environmental Review Commission (ERC) and the Joint Legislative Utility Review Committee (JLURC).

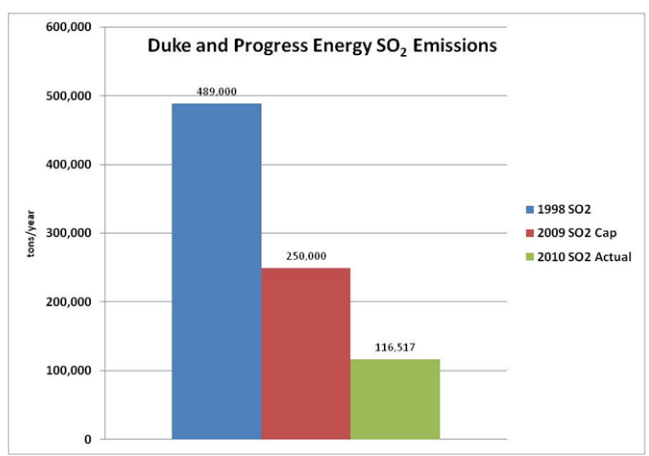
The Act, in Section 9, requires Duke Energy Carolinas, LLC (Duke Energy), and Progress Energy Carolinas, Inc. (Progress Energy), to submit annual reports to DENR and the Commission containing certain specified information. Duke Energy and Progress Energy filed reports, with DENR and the Commission, by cover letters dated March 29 and April 1, 2011, respectively. Specifically, such reports were submitted in compliance with the requirements of G.S. 62-133.6(i). Duke Energy's and Progress Energy's reports are attached, and made part of this report, as Attachments A and B, respectively.

Additionally, by letter dated May 13, 2011, the Secretary of DENR wrote to the Commission stating that, pursuant to G.S. 62-133.6(j), DENR has reviewed the information provided and has determined that the submittals comply with the Act. The Secretary further stated that the plans and schedules of the Companies appear adequate to achieve the emission limitations set out in G.S. 143-215.107D.

Significantly, 2007 marked the first step in meeting the emission reductions required by the Clean Smokestacks Act. Duke Energy was limited to 35,000 tons of oxides of nitrogen (NOx) in any calendar year beginning 1 January 2007, and Progress Energy was limited to 25,000 tons of NOx. Both utilities reported to have met their respective limits as recorded through continuous emission monitoring (CEM) data. DENR/DAQ has verified the utilities' CEM data with those reported to the United States Environmental Protection Agency (EPA).

The end of 2009 marked the second milestone in emission reductions, when Duke Energy had to further reduce its calendar year NOx emissions to 31,000 tons, and Progress Energy was required to emit less than 25,000 tons (combined cap of 56,000 tons NOx). Both utilities were also required to reduce their calendar year sulfur dioxide (SO_2) emissions, Duke Energy to 150,000 tons and Progress Energy to 100,000 tons (combined cap of 250,000 tons SO_2). For calendar year 2010, both utilities reported that they have continued to meet their respective limits. This has been confirmed by DENR/DAQ. The figure below shows the decrease in NOx and SO_2 emissions as a result of control measures implemented by Progress Energy and Duke Energy on a combined basis:





The next milestone in emission reductions occurs in 2013, when Duke Energy and Progress Energy must reduce their annual SO_2 emissions to 80,000 tons and 50,000 tons, respectively (combined cap of 130,000 tons SO_2). Duke Energy's SO_2 emissions are well below the 2013 cap (based on calendar year 2010 data). Progress Energy's is expected to meet its 2013 target in the coming years with the recently planned retirement of the Lee coal-fired plant and its replacement with a combined-cycle natural gas-fired plant.

This report is presented to meet the reporting requirement of the Act pertaining to DENR and the Commission, as discussed above, and is submitted jointly by DENR and the Commission. The report is structured to address the various actions that have occurred pursuant to the provisions of Sections 9, 10, 11, 12, and 13 of the Act. Reports of actions under these Sections describe the extent of implementation of the Act to this date.

I. Section 9(c) of the Act, Codified as Section 62-133.6(c) of the North Carolina General Statutes

G.S. 62-133.6(c) provides: *The investor-owned public utilities shall file their compliance plans, including initial cost estimates, with the Commission and the Department of Environment and Natural Resources not later than 10 days after the date on which this section becomes effective. The Commission shall consult with the Secretary of Environment and Natural Resources and shall consider the advice of the Secretary as to whether an investor-owned public utility's proposed compliance plan is adequate to achieve the emissions limitations set out in G.S. 143-215.107D.*

Status: North Carolina's IOUs, Progress Energy and Duke Energy, filed their initial compliance plans as required in June and July of 2002, respectively, in accordance with G.S. 62-133.6(c), Section 9(c) of Session Laws 2002-4, the Clean Smokestacks Act. DENR/DAQ reviewed this information and determined that the submittals complied with the Act and, as proposed, appeared adequate to achieve the emission limitations set out in G.S. 143-215.107D. The Commission agreed with and accepted DENR/DAQ's evaluations and findings.

II. Section 9(d) of the Act, Codified as Section 62-133.6(d) of the North Carolina General Statutes

G.S. 62-133.6(d) provides: *Subject to the provisions of subsection (f) of this section, the Commission shall hold a hearing to review the environmental compliance costs set out in subsection (b) of this section. The Commission may modify and revise those costs as necessary to ensure that they are just, reasonable, and prudent based on the most recent cost information available and determine the annual cost recovery amounts that each investor-owned public utility shall be required to record and recover during calendar years 2008 and 2009. In making its decisions pursuant to this subsection, the Commission shall consult with the Secretary of Environment and*

Natural Resources to receive advice as to whether the investor-owned public utility's actual and proposed modifications and permitting and construction schedule are adequate to achieve the emissions limitations set out in G.S. 143-215.107D. The Commission shall issue an order pursuant to this subsection no later than 31 December 2007.

Commission proceedings conducted in compliance with this provision of the Act and related Commission rulings were comprehensively discussed in DENR and the Commission's 2009 Clean Smokestacks Act joint report to the ERC and the JLURC. For a complete detailed explanation of such matters, please refer to Part II of the 2009 report, beginning on Page 2.

III. Section 9(i) of the Act, Codified as Section 62-133.6(i) of the North Carolina General Statutes

G.S. 62-133.6(i) provides: *An investor-owned public utility that is subject to the emissions limitations set out in G.S. 143-215.107D shall submit to the Commission and to the Department of Environment and Natural Resources on or before 1 April of each year a verified statement that contains all of the following [specified information]:*

The following are the eleven subsections of G.S. 62-133.6(i) and the related responses from Progress Energy and Duke Energy for each subsection:

1. G.S. 62-133.6(i)(1) requires: *A detailed report on the investor-owned public utility's plans for meeting the emissions limitations set out in G.S. 143-215.107D.*

Progress Energy Response: "PEC originally submitted its compliance plan on July 29, 2002. Appendix A [of the attached Progress Energy submittal dated April 1, 2011, i.e., Attachment B of this report] contains an updated version of this plan, effective April 1, 2011."

Duke Energy Response: "Exhibits A and B [of the attached Duke Energy submittal dated March 29, 2011, i.e., Attachment A of this report] outline the [plan for] technology selections by facility and unit, actual and projected operational dates, actual and expected emission rates, and the corresponding tons of emissions that demonstrate compliance with the provisions of G.S. 143-215.107D." The following changes to the plan for meeting emissions limits as compared to past compliance plans have been identified:

NO_x Compliance

"Emission Rate Changes – Expected rates for certain units have been adjusted in this 2011 update based on operating experience in 2010 with installed controls, targeted future performance and planned retirements."

SO_2 Compliance
"Emission Rate Changes – Expected rates have been adjusted in this 2011 update based on operating experience in 2010 with installed controls, targeted future performance and planned retirements."

2. G.S. 62-133.6(i)(2) requires: *The actual environmental compliance costs incurred by the investor-owned public utility in the previous calendar year, including a description of the construction undertaken and completed during that year.*

Summary of Progress Energy Report: The actual environmental compliance net costs (see Attachment B, Appendix B) incurred by Progress Energy in calendar year 2010 were $5.3 million. Such costs, in all material respects, were related to remediation work with respect to the wastewater treatment settling ponds at the Company's Roxboro plant.

Summary of Duke Energy Report: The actual environmental compliance net costs (see Attachment A, Exhibit C) incurred by Duke Energy in calendar year 2010 were $78.1 million. Such costs, in all materials respects, were incurred with respect to flue gas desulfurization (FGD) at the Company's Allen and Cliffside Steam Stations.

3. G.S. 62-133.6(i)(3) requires: *The amount of the investor-owned public utility's environmental compliance cost amortized in the previous calendar year.*

Summary of Progress Energy Report: Progress Energy amortized $0 environmental compliance cost in 2010. As reflected in earlier reports, Progress Energy has previously amortized a total of $584.1 million. No additional amortization is anticipated.

Summary of Duke Energy Report: Duke Energy amortized $0 environmental compliance cost in 2010. As reflected in earlier reports, Duke Energy has previously amortized a total of $1.05 billion. No additional amortization is anticipated.

4. G.S. 62-133.6(i)(4) requires: *An estimate of the investor-owned public utility's environmental compliance costs and the basis for any revisions of those estimates when compared to the estimates submitted during the previous year.*

Summary of Progress Energy Report: Progress Energy reported that its total estimated net capital costs (that is, excluding the portion for which the Power Agency is responsible) are currently projected to be $1.056 billion. Such amount is virtually unchanged from the Company's April 2010 cost estimate of $1.060 billion.

Progress Energy's current cost estimate of $1.056 billion, which excludes allowance for funds used during construction (AFUDC), is $243 million or 30% greater than the original 2002 cost estimate of $813 million.

Summary of Duke Energy Report: Duke Energy reported that there has been no significant change to the scope or timing associated with any of its projects but that forecasts for active projects have been updated as compared to those contained in the Company's 2010 report. Duke Energy's current cost estimate of its compliance costs is $1.843 billion, excluding AFUDC. Such amount is basically unchanged, in all material respects, from its cost estimate of $1.809 billion as contained in its 2010.

Duke Energy's current cost estimate of $1.843 billion is $343 million or 23% greater than the original 2002 estimate of $1.5 billion.

5. G.S. 62-133.6(i)(5) requires: *A description of all permits required in order to comply with the provisions of G.S. 143-215.107D for which the investor-owned public utility has applied and the status of those permits or permit applications.*

Summary of Progress Energy Response:

<u>Roxboro Plant</u>

Erosion and Sediment Control Plan
A revised plan for an increase in disturbed land for a Construction Borrow area for the Waste Water Treatment Ponds was submitted on March 16, 2010, and approved on March 19, 2010. This Erosion and Sediment Control Plan was closed as documented in the Sedimentation Inspection Report (submitted on September 28, 2010).

Dam Safety Submittals
On April 28, 2010, an application for Certificate of Approval for construction of a new East Gypsum settling pond was submitted to the DENR Division of Land Resources. Final approval to impound the new East Settling Pond was received on November 16, 2010.

On June 8 and September 27, 2010, applications for a Certificate of Approval for repair of the West Gypsum settling pond were submitted to the DENR Division of Land Resources.

Summary of Duke Energy Response:

<u>Allen</u>

- Land Permit to Operate Phase 1 cell 2 – submitted 9/3/10; granted 12/8/10.

<u>Belews Creek</u>

- No change in compliance permitting.

Cliffside (Unit 5 FGD)

- Submitted Air Permit Application for Cliffside Station FGD Project (Common Support Facilities for Units 5&6); received permit on 2/3/10.
- Received permit to operate FGD Landfill on 9/7/10.

Marshall Steam Station FGD

- Submitted and received approval to Construct Vertical Flow Constructed Wetlands.

6. G.S. 62-133.6(i)(6) requires: *A description of the construction related to compliance with the provisions of G.S. 143-215.107D that is anticipated during the following year.*

Summary of Progress Energy Response: At the Roxboro plant, "work on the settling ponds will continue through their anticipated completion in the 3rd quarter. There is no further construction anticipated."

Summary of Duke Energy Response: At the Allen Steam Station, installation of additional relays to eliminate reliability issue with the Belmont Tie will be performed. Additionally, absorber vessel corrosion analysis will be performed. This will include a third party review of corrosion issues discovered during equipment inspections. Activities at the Cliffside Steam Station Unit 5 FGD will consist of installation of 230 kV breakers on FGD Aux Transformers, a variety of closeout activities, and achieving final completion.

7. G.S. 62-133.6(i)(7) requires: *A description of the applications for permits required in order to comply with the provisions of G.S. 143-215.107D that are anticipated during the following year.*

Progress Energy Response: "PEC has completed the permitting required to comply with the provisions of G.S. 143-215.107D. Approval to impound the repaired West Settling Pond [Roxboro Plant] is expected to be requested from the Division of Land Resources in the second quarter of 2011."

Duke Energy Response: "No additional applications for permits are expected."

8. G.S. 62-133.6(i)(8) requires: *The results of equipment testing related to compliance with G.S. 143-215.107D.*

Progress Energy Response: "No additional equipment testing related to compliance with G.S. 143-215.107D was performed in 2010."

Duke Energy Response: The Cliffside Steam Station FGD (Unit 5) system was commissioned in 2010 and a Performance Test was conducted on November 18 and 19, 2010. "The Performance Test results reported by the testing contractor indicated the FGD system's SO_2 removal efficiency achieved its performance guarantee of 99 percent."

9. G.S. 62-133.6(i)(9) requires: *The number of tons of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emitted during the previous calendar year from the coal--fired generating units that are subject to the emissions limitations set out in G.S. 143-215.107D.*

Both utilities determine their actual emissions through CEM data. The raw CEM data are recorded and verified by the utilities, and then reported to the EPA.

Progress Energy Response: "The total calendar year 2010 emissions from the affected coal-fired Progress Energy Carolinas units are:

- NOx 24,741 tons
- SO_2 73,748 tons"

DENR/DAQ has verified these emissions using EPA's Clean Air Market Division database. It should be noted that 2007 marked the first limit imposed by the Act, requiring Progress Energy to meet a limit of 25,000 tons of NOx and maintain this emission limit in future years. 2009 marked the second emission limit of 100,000 tons of SO_2. Progress Energy's reported NOx and SO_2 emissions for 2010 comply with the limits specified in the Act. The Company has achieved emissions that are well below the required levels.

The Company's next steps to comply with the Act are to continue to meet the NOx and SO_2 emissions limit of 25,000 tons and 100,000 tons, respectively. It must further reduce its SO_2 emissions to 50,000 tons in 2013 and maintain that level on an annual basis in future years.

Duke Energy Response: "In the 2010 calendar year, 22,438 tons of NOx and 42,769 tons of SO_2 were emitted from the Duke Energy Carolinas coal-fired units located in North Carolina and subject to the emissions limitations set out in G.S. 143-215.107D."

DENR/DAQ has verified these emissions using EPA's Clean Air Market Division database. As previously noted, the first emissions limitation imposed by the Act became operative in 2007, requiring Duke Energy to meet a limit of 35,000 tons of NOx. By 2009, Duke was required to further reduce its annual NOx emissions to 31,000 tons and reduce SO_2 emissions to 150,000 tons per year. Duke Energy's reported emissions for 2010 comply with the NOx and SO_2 limits specified in the Act. The Company has achieved emissions that are well below the required levels.

The Company's next steps to comply with the Act are to continue to meet the annual NOx and SO_2 emission limits of 31,000 tons and 150,000 tons per year, respectively. In 2013, the SO_2 emission limit drops to 80,000 tons. The Company is already meeting that target by a wide margin.

10. G.S. 62-133.6(i)(10) requires: *The emissions allowances described in G.S. 143-215.107D(i) that are acquired by the investor-owned public utility that result from compliance with the emissions limitations set out in G.S. 143-215.107D.*

Progress Energy Response: "During 2010, PEC did not acquire any allowances as a result of compliance with the emission limitations set out in N.C. General Statute 143-215.107D."

DENR/DAQ neither agrees nor disagrees with the above statement at this time. DENR/DAQ is in the process of verifying if 2010 allowance transfer is required from Progress Energy.

For compliance year 2009, DENR/DAQ has verified that Progress Energy surrendered 41,259 tons SO_2 allowances to the state of North Carolina. No NO_x allowances were surrendered in 2009.

Duke Energy Response: "In order to comply with the June 21, 2002 Agreement Under Seal, on 2/14/2011, Duke Energy Carolinas surrendered to the state of North Carolina 28,492 SO_2 allowances and 1,958 annual NO_x allowances for compliance year 2009. The agreement calls for the surrender of all allowances allocated by the US EPA that are in excess of the limits in this Legislation. For 2009, those limits were 150,000 tons SO_2 and 31,000 tons NO_x."

DENR/DAQ agrees with the above statement, and has verified Duke Energy's surrender of allowances for compliance year 2009.

DENR/DAQ has not received a 2010 allowance transfer statement from Duke Energy as of the date of this report.

11. G.S. 62-133.6(i)(11) requires: *Any other information requested by the Commission or the Department of Environment and Natural Resources.*

Progress Energy Response: "There have been no additional requests for information from the North Carolina Utilities Commission or the Department of Environment and Natural Resources since the last report."

Duke Energy Response: "No additional information has been requested to be included in this annual data submittal."

IV. Section 10 of the Act provides: *It is the intent of the General Assembly that the State use all available resources and means, including negotiation, participation in interstate compacts and multistate and interagency agreements, petitions pursuant to 42 U.S.C. § 7426, and litigation to induce other states and entities, including the Tennessee Valley Authority, to achieve reductions in emissions of oxides of nitrogen*

(NOx) and sulfur dioxide (SO_2) comparable to those required by G.S. 143-215.107D, as enacted by Section 1 of this act, on a comparable schedule. The State shall give particular attention to those states and other entities whose emissions negatively impact air quality in North Carolina or whose failure to achieve comparable reductions would place the economy of North Carolina at a competitive disadvantage.

DENR/DAQ and Department of Justice (Attorney General) Activities to Implement this Section:

The State continues to pursue opportunities to carry forward the Legislature's objectives in Section 10 of the Act. The State reports the following recent activities and developments:

1) On January 30, 2006, the State, through the Attorney General, sued the Tennessee Valley Authority (TVA) in federal district court in Asheville. The suit alleges that emissions of SO_2 and NOx from TVA's fleet of coal-fired power plants are inadequately controlled and therefore create a public nuisance. The Attorney General asked the court to require TVA to install NOx and SO_2 controls to abate the public nuisance.

   On January 13, 2009, the court found that four TVA coal-fired generating stations are creating a public nuisance in North Carolina. These facilities are the Bull Run, John Sevier, and Kingston plants in eastern Tennessee and the Widows Creek plant in northeastern Alabama. The Judge ordered that each unit of each facility install modern pollution controls for SO_2 and NOx and meet emission limits that are consistent with the continuous operation of such controls. The court ordered that TVA meet these limits on a staggered schedule ending in 2013.

   On July 26, 2010, the United States Court of Appeals for the Fourth Circuit reversed the judgment, primarily on the ground that the action was pre-empted by the Clean Air Act. North Carolina has petitioned the United States Supreme Court to review the case and that petition is pending.

   Meanwhile, on April 14, 2011, North Carolina, TVA, and several other parties agreed to a comprehensive settlement of a variety of air pollution allegations. The settlement was lodged with the federal district court in eastern Tennessee. The detailed settlement would, among other things, (1) subject SO_2 and NOx emissions at all of TVA's coal-fired facilities to system-wide caps that decline on an annual basis to permanent levels of 110,000 tons of SO_2 in 2019 and 52,000 tons of NOx in 2018; (2) require TVA to install modern pollution controls on or shutdown all of its coal-fired units (except certain units at the Shawnee plant in western Kentucky); and (3) require TVA to pay North Carolina \$11.2 million to fund mitigation projects in North Carolina. The settlement must be approved by the court before it becomes effective.

2) On July 8, 2005, the Attorney General filed in the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) a petition for review of the United States Environmental Protection Agency's (EPA's) Clean Air Interstate Rule (CAIR). CAIR was designed to reduce emissions of SO_2 and NOx from power plants that cause particulate matter and ozone pollution across the eastern United States. Among other things, the State alleged that CAIR fails to take into account significant air quality problems in North Carolina, fails to guarantee a remedy to North Carolina because the rule relies too heavily on the trading of pollution credits, and fails to require controls to be installed expeditiously.

   On July 11, 2008, the D.C. Circuit granted North Carolina's petition in part. The court found that CAIR's trading program failed to comply with the Clean Air Act because it did not guarantee that emission reductions would be targeted to the downwind areas that need them, that EPA improperly refused to consider North Carolina's problems with maintaining national air quality standards, and that EPA set the CAIR pollution reduction deadlines without proper consideration of the tight deadlines faced by impacted States. The court also granted petitions from other parties on other issues.

   In response to the court's judgment, on July 6, 2010, EPA proposed the Clean Air Transport Rule (CATR). The rule would cap SO_2 and NOx emissions from States that impact attainment or maintenance of the national particulate matter and ozone standards in downwind states. Unlike CAIR, the CATR, as proposed, would largely abandon the interstate trading of pollution allowances. The deadlines for these emissions reductions would be coordinated with the needs of the downwind States and would ensure that the delay caused by the litigation would not negatively impact downwind States. EPA is expected to finalize the rule in early summer 2011. On March 14, 2011, the Attorney General, along with the Attorney General of New York, sent a letter to the EPA Administrator requesting that EPA establish a schedule for completing the rule by the end of June 2011.

3) On July 8, 2005, the Attorney General filed a petition with EPA requesting that EPA administratively reconsider certain aspects of CAIR. EPA denied this petition. This petition was reviewed by the D.C. Circuit and resolved along with the petition for review discussed in the preceding item.

4) On March 18, 2004, the State filed a petition under §126 of the Clean Air Act requesting that EPA impose NOx and/or SO_2 controls on large coal-fired utility boilers in 13 upwind states that impact North Carolina's air quality. On March 15, 2006, EPA denied the State's petition. The Attorney General then petitioned EPA for administrative reconsideration, which was also denied. The Attorney General petitioned the D.C. Circuit for judicial review of both of these decisions.

Based on subsequent events, including the court's holding in the CAIR case, EPA conceded that it must reconsider its denial of North Carolina's §126 petition. The court agreed and, on March 5, 2009 remanded the matter back to EPA for further consideration. As part of the settlement with TVA, North Carolina agreed to withdraw the petition as it relates to TVA once the settlement becomes final.

5) In April 2008, EPA finalized a rule that exempts sources of NOx in Georgia from any summertime NOx cap under EPA's "NOx SIP Call" rule. The NOx SIP Call was designed to help downwind States reduce ambient levels of ozone. Sources in Georgia are also exempt from summertime NOx controls for ozone pollution under CAIR. On June 20, 2008, the Attorney General petitioned the D.C. Circuit for review of EPA's decision to exempt Georgia sources from the NOx SIP Call. On November 24, 2009, the court ruled that North Carolina did not have standing to sue EPA on this issue. The court concluded that, through the recent adoption and/or implementation of NOx reduction rules by Georgia, sources in Georgia have reduced NOx emissions to levels consistent with the NOx SIP Call.

V. Section 11 of the Act provides: *The Environmental Management Commission shall study the desirability of requiring and the feasibility of obtaining reductions in emissions of oxides of Nitrogen (NOx) and Sulfur Dioxide (SO_2) beyond those required by G.S. 143-215.107D, as enacted by Section 1 of this act. The Environmental Management Commission shall consider the availability of emission reduction technologies, increased cost to consumers of electric power, reliability of electric power supply, actions to reduce emissions of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) taken by states and other entities whose emissions negatively impact air quality in North Carolina or whose failure to achieve comparable reductions would place the economy of North Carolina at a competitive disadvantage, and the environment, and the natural resources, including visibility. In its conduct of this study, the Environmental Management Commission may consult with the Utilities Commission and the Public Staff. The Environmental Management Commission shall report its findings and recommendations to the General Assembly and the Environmental Review Commission annually beginning 1 September 2005.*

Note: Session Law 2010-142 changed the beginning date of the requirements of this Section to September 1, 2011.

Environmental Management Commission and DENR Response: A letter was submitted to the Environmental Review Commission from Mr. Stephen T. Smith, Environmental Management Commission Chairman, dated October 12, 2009, which stated the following:

> Since the CSA was passed in June 2002, significant Federal regulatory changes have occurred. The federal Clean Air Interstate Rule (CAIR) was promulgated to require North Carolina's neighboring states to achieve major reductions in NO_x and SO_2 – reductions that require installation of state-of-the-art control equipment. Installation of state-of-the-art

emissions control equipment was already required by the CSA; however CAIR may require controls on additional generating units. Although on July 11, 2008, the D.C. Circuit Court vacated CAIR, on December 23, 2008, the Court granted USEPA's petition to remand the case without vacatur, allowing CAIR to remain in effect until a replacement rule is promulgated. On August 7, 2009, consistent with the Court's order, USEPA proposed approval of North Carolina's Clean Air Interstate Rules (NC-CAIR) into the State Implementation Plan (SIP). This approval is based, in part, on North Carolina's use of the NO_x and SO_2 budgets outlined in the remanded rule. CAIR NO_x and SO_2 emissions allowances for North Carolina utilities are even lower than those set by the Clean Smokestacks Act. Final SIP approval by USEPA will likely occur in late October 2009.

On March 12, 2008, USEPA promulgated a more stringent 8-hour standard for ozone, revising the standard for the first time in more than a decade. In March 2009, the North Carolina Division of Air Quality made recommendations to USEPA on what areas of the state should be designated as nonattainment under the new standard. However, on September 16, 2009, the USEPA announced it would reconsider the 2008 ozone standard. The USEPA will propose a more-stringent ozone standard in December 2009 and issue a final decision by August 2010. The state's attainment demonstration SIP will be due to USEPA in December 2013 identifying any new NO_x control strategies that may be needed to attain the new standard. That analysis may require additional targeted emission reductions beyond CSA in certain critical areas in North Carolina and in other states.

On July 15, 2009, USEPA proposed a revision to the current annual NOx standard by adding a 1-hour daily NOx standard. Although this proposal seems to be aimed at emission reductions from sources other than utilities, the North Carolina Division of Air Quality is studying the potential effect of this new proposal on all emission sources.

In judicial actions pursuant to Section 10 of the Clean Smokestacks Act authorizing other actions to achieve emissions reduction in NO_x and SO_2 from other states and entities, the North Carolina Attorney General on January 20, 2006, filed suit alleging that NO_x and SO_2 emissions from TVA power plants were inadequately controlled and created a public nuisance. On January 13, 2009, the federal District Court in Asheville found four TVA coal-fired generating facilities within 100 miles of North Carolina to be creating a public nuisance in the state. The court ordered that each unit at each of these facilities meet emission limits for NO_x and SO_2 consistent with the installation and continuous operation of modern pollution controls no later than December 2013. TVA has appealed the decision of the Court.

In other actions by the North Carolina Attorney General, a petition was filed under §126 of the Clean Air Act requesting that USEPA impose NO_x and SO_2 controls on large coal-fired utility boilers in 13 upwind states that impact air quality in North Carolina. Although USEPA originally denied both the petition and administrative reconsideration, the State petitioned the D.C. Circuit for judicial review. Based in part upon the outcome of the CAIR case, USEPA conceded that it must reconsider its earlier denial and the court remanded the matter back to the USEPA on March 5, 2009.

In April 2008, USEPA exempted sources of NO_x in Georgia from any summertime NO_x emissions cap. The NO_x cap had been required by a separate federal rule designed to help downwind states reduce ambient levels of ozone. Sources in Georgia are also exempt from summertime NO_x controls for ozone under the remanded CAIR. On June 20, 2008, the North Carolina Attorney General petitioned the D.C. Circuit for a review of USEPA's April 2008 action to exempt Georgia and a decision is expected on this petition in early 2010. The outcome of this case could impact the extent to which Georgia sources are controlled or participate in Federal cap and trade programs. The Division of Air Quality will need to analyze the downwind impacts in North Carolina as they study whether additional reductions are needed beyond CSA.

SL2009-390, passed in the 2009-2010 legislative session, has the potential to further reduce power plant emissions of NO_x and SO_2 from Progress Energy. SL2009-390 amends G.S. § 62-110.1 by allowing an expedited certification process through the Utilities Commission when coal-fired generating units are retired and replaced by natural gas generating units. When compared to coal, natural gas will achieve reductions of NO_x and SO_2 and other air pollutants, promoting cleaner air. Progress Energy has formally announced that three coal-fired boilers at its Lee Plant in Wayne County, N.C. will be replaced by gas-fired turbines by 2013. It is anticipated that federal climate change legislation may also result in further reductions of NO_x and SO_2 emissions as utility companies decide how to most economically address future required reductions of carbon dioxide emissions.

Given the recent actions by the state, the federal government, the Asheville federal District Court and the D.C. Circuit Court affecting power plant emissions and NO_x and SO_2 regulation, and given possible federal climate change legislation, it is recommended that the study of further State action to achieve additional reduction of these air contaminants be presented on December 1, 2013. That reporting date will:

- Allow the affected public utilities in North Carolina time to implement their control strategies to meet the compliance deadline under CSA,

- Give the Division of Air Quality time to quantify air quality impacts from CSA compliance, and
- Give industry and the Division time to implement new Federal rules and court actions.

Any reports made prior to the implementation of these control strategies would likely provide little new or beneficial information beyond the Division's ongoing analyses to meet other obligations, such as the federal Clean Air Act requirements. Furthermore, since evolution of new control technologies is fairly long-term, I recommend that reporting thereafter be on a three-year basis.

VI. Section 12 of the Act provides: *The General Assembly anticipates that measures implemented to achieve the reductions in emissions of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) required by G.S. 143-215.107D, as enacted by Section 1 of this act, will also result in significant reductions in the emissions of mercury from coal-fired generating units. The Division of Air Quality of the Department of Environment and Natural Resources shall study issues related to monitoring emissions of mercury and the development and implementation of standards and plans to implement programs to control emissions of mercury from coal-fired generating units. The Division shall evaluate available control technologies and shall estimate the benefits and costs of alternative strategies to reduce emissions of mercury. The Division shall annually report its interim findings and recommendations to the Environmental Management Commission and the Environmental Review Commission beginning 1 September 2003. The Division shall report its final findings and recommendations to the Environmental Management Commission and the Environmental Review Commission no later than 1 September 2005. The costs of implementing any air quality standards and plans to reduce the emission of mercury from coal-fired generating units below the standards in effect on the date this act becomes effective, except to the extent that the emission of mercury is reduced as a result of the reductions in the emissions of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) required to achieve the emissions limitations set out in G.S. 143-215.107D, as enacted by Section 1 of this act, shall not be recoverable pursuant to G.S. 62-133.6, as enacted by Section 9 of this act.*

DAQ Actions to Implement this Section: DENR/DAQ submitted reports in September of 2003, 2004, and 2005, as required by this Section. The first report primarily focused on the "state of knowledge" of the co-benefit of mercury control that would result from the control of NOx and SO_2 from coal-fired utility boilers. Also, preliminary estimates were made for this co-benefit for North Carolina utility boilers based on the initial plans submitted by Progress Energy and Duke Energy. The second report primarily focused on "definition of options." DENR/DAQ has also submitted the third and final report titled Mercury Emissions and Mercury Controls for Coal-Fired Electrical Utility Boilers. In 2006, DENR/DAQ developed a state mercury rule that goes beyond the now-vacated federal Clean Air Mercury Rule (CAMR). The North Carolina mercury rules, contained in Section 15A NCAC 02D .2500, became effective January 1, 2007. The coal-fired units of Duke Energy and Progress Energy have to meet this State-only requirement. This requirement is that the emissions of mercury from each coal-fired unit at Duke Energy and Progress Energy have to be controlled to the maximum degree that is technically and economically feasible or shut down by a prescribed date.

On March 16, 2011 the EPA proposed national standards to limit mercury, arsenic, and other toxic pollution from new and existing coal- and oil-fired electric utility steam generating units. The rule replaces the court-vacated CAMR, and is expected to be promulgated before the end of 2011. Although EPA's final requirements have yet to be set, mercury reductions in North Carolina remain on schedule. The controls needed to comply with the Clean Smokestacks Act provide significant co-benefits in the form of mercury emission reductions. Therefore, mercury emission reductions in North Carolina will continue through the year 2013. By 2018, all of the Duke Energy and Progress Energy units will either have controls in place or be shut down, as a matter of State law. The Clean Smokestacks Act greatly reduces mercury emissions (as a co-benefit of the NOx and SO_2 controls) from sources within the State.

As noted earlier herein, on July 6, 2010, EPA proposed the Clean Air Transport Rule. The significance of the proposed rule has been previously explained and such explanation, in large measure, does not need to be repeated here. However, it is worth repeating to note that EPA is expected to finalize the rule in summer 2011; and that, based on the proposed rule, it is reasonable to believe that the final rule will require emissions reductions beyond Clean Smokestacks, and mercury reduction is likely to be an added benefit. It is expected that CATR reductions from our border states will provide further reductions in mercury deposition in North Carolina.

VII. Section 13 of the Act provides: *The Division of Air Quality of the Department of Environment and Natural Resources shall study issues related to the development and implementation of standards and plans to implement programs to control emissions of carbon dioxide (CO_2) from coal-fired generating units and other stationary sources of air pollution. The Division shall evaluate available control technologies and shall estimate the benefits and costs of alternative strategies to reduce emissions of carbon dioxide (CO_2). The Division shall annually report its interim findings and recommendations to the Environmental Management Commission and the Environmental Review Commission beginning 1 September 2003. The Division shall report its final findings and recommendations to the Environmental Management Commission and the Environmental Review Commission no later than 1 September 2005. The costs of implementing any air quality standards and plans to reduce the emission of carbon dioxide (CO_2) from coal-fired generating units below the standards in effect on the date this act becomes effective, except to the extent that the emission of carbon dioxide (CO_2) is reduced as a result of the reductions in the emissions of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) required to achieve the emissions limitations set out in G.S. 143-215.107D, as enacted by Section 1 of this act, shall not be recoverable pursuant to G.S. 62-133.6, as enacted by Section 9 of this act.*

DENR Actions to Implement this Section: DENR/DAQ submitted reports in September of 2003, 2004, and 2005, as required by this Section. The first report primarily focused on the "state of knowledge" and actions being taken or planned elsewhere regarding CO_2 control from coal-fired utility boilers. The second report primarily focused on "definition of options". DENR/DAQ submitted the third and final report titled, "Carbon Dioxide (CO_2) Emission Reduction Strategies for North Carolina", to the Environmental Management Commission and the Environmental Review Commission as required. Numerous recommendations were set forth in this report, including a recommendation for a North Carolina Climate Action Plan.

The North Carolina Global Warming/Climate Change Bill (HB 1191/SB 1134) was enacted during the 2005 Session of the General Assembly. Along with the passage of the bill, the North Carolina 2005 Session of the General Assembly passed the Global Climate Change Act. This act established a Legislative Commission on Global Climate Change (LCGCC). Additionally, a formalized stakeholder group, the Climate Action Plan Advisory Group (CAPAG), was formed by DENR. The CAPAG's purpose was to assess possible mitigation options, carry out analysis, and make recommendations that state policy makers could consider for state-level climate action planning which included CO_2 and other greenhouse gas (GHG) reductions. Impacts on economic opportunities and co-benefits of proposed potential mitigation options were evaluated through a formal consensus-based stakeholder process. Determination of economic benefits to North Carolina was also assessed. The inaugural meeting of the CAPAG was held on February 16, 2006, and the CAPAG made recommendations regarding 56 mitigation options in the following five sectors: (1) Agriculture, Forestry, and Waste; (2) Energy Supply; (3) Transportation and Land Use; (4) Residential, Commercial, and Industrial; and (5) Cross Cutting (for issues that cut across different sectors, such as establishing a GHG registry). The work of developing these recommendations and evaluating potential GHG emissions reductions was divided among five technical work groups.

The CAPAG commissioned a secondary economic analysis expanding the technical work groups' implementation-only cost analysis to also include jobs impacts. This analysis, conducted by Appalachian State University (ASU), was incorporated into the final CAPAG report. A summary conclusion from the ASU analysis stated:

> By 2020, the mitigation options analyzed would result in the creation of more than 15,000 jobs, $565 million in employee and proprietor income, and $302 million in gross state product. For the study period, 2007-2020, the mitigation options analyzed would generate more than $1.2 billion net present value (NPV) in net gross state product.

One of the earlier recommendations of the CAPAG, a Renewable Energy and Energy Efficiency Portfolio Standard (REPS), was enacted by Session Law 2007-397 (SB3) and codified under G.S. 62-133.8. The Utilities Commission, in the context of an extensive rulemaking proceeding, has developed and issued comprehensive rules implementing the provisions of G.S. 62-133.8, including provisions related to REPS. The final CAPAG report can be found at http://www.ncclimatechange.us/.

On October 28, 2008, the Air Quality Committee of the Environmental Management Commission held a public hearing on proposed amendments to the Air Quality Annual Emissions Reporting Rule for major stationary (point) sources. The amendments propose to add GHGs including CO_2, to the list of compounds reported as emissions releases annually by major point sources, including electric power utilities such as Duke Energy and Progress Energy. An inventory of GHG emissions was identified by the CAPAG technical workgroup on cross-cutting issues and unanimously supported as a mitigation option. On October 30, 2009, EPA promulgated the "Mandatory Reporting of Greenhouse Gases", a regulation to require reporting of GHG emissions from certain large emissions sources. The rule would apply to electricity generation. On November 19, 2009, the Environmental Management Commission chose not to take action on amendments to the NC Annual Emissions Reporting Rule (15A NCAC 02Q .0207) because GHG emissions data collected under the federal rule are considered to be sufficient in content and are expected to be released to the public within a reasonable timeframe.

On December 7, 2009, the EPA Administrator signed two distinct findings regarding GHGs under Section 202(a) of the Clean Air Act (CAA). In the Endangerment Finding, the Administrator found "that the current and projected concentrations of the six key well-mixed greenhouse gases--carbon dioxide (CO2)…--in the atmosphere threaten the public health and welfare of current and future generations." In the Cause or Contribute Finding, the Administrator found "that the combined emissions of these well-mixed greenhouse gases from new motor vehicles and new motor vehicle engines contribute to the greenhouse gas pollution which threatens public health and welfare."

On April 1, 2010, the EPA set national emission standards under Section 202(a) of the CAA to control GHGs from passenger cars and light-duty trucks, and medium-duty passenger vehicles, as part of a joint rulemaking with the National Highway Traffic Safety Administration (NHTSA). The standards would be phased in beginning with model year 2012 through 2016. The implementation of EPA's light-duty vehicle standard will make GHG emissions subject to regulation under the CAA for the first time. As written in the CAA, air pollutants that are subject to regulation under the statute, are subject to prevention of significant deterioration (PSD) and operating-permit provisions for stationary sources (CAA Section 169(3)). To identify when stationary sources are subject to regulation, the EPA completed its reconsideration of the December 18, 2008 memorandum entitled "EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program." The final action, issued on March 29, 2010, confirms that "any new pollutant that EPA may regulate becomes covered under the PSD program on the date when the EPA rule regulating that new pollutant takes effect." It then clarifies that for GHGs that date will be January 2, 2011, when the vehicle rule took effect.

To limit the number of stationary sources that would be subject to GHG regulations, the EPA promulgated a rule on May 13, 2010 that would apply a tailored approach to GHG regulations under the PSD and Title V programs of the CAA. The

Tailoring Rule temporarily raises statutory thresholds and sets a PSD significance level for GHGs. By tailoring the applicability thresholds, only large emitting sources would be affected. EPA is phasing in the permit requirements. During the first half of 2011, only those facilities that already must apply for permits, as a result of non-GHG emissions, are required to address their GHG emissions in their permit applications. Other large sources will be phased in between the latter half of 2011 and 2013. Sources subject to the Clean Smokestacks Act are likely to be affected by the GHG Tailoring Rule. Future modifications at these sites, determined to meet significant emission levels, would require a review of best available control technologies. This will most likely consist of energy efficiency improvements at affected sites.

On December 23, 2010, the EPA entered into two proposed settlement agreements to issue rules that will address GHG emissions from fossil fuel-fired power plants and refineries. The CAA requires the EPA to set new source performance standards (NSPS) for industrial categories that cause, or significantly contribute to, air pollution. These standards set the level of pollution new facilities may emit and address air pollution from existing facilities. The EPA is expected to propose NSPS for power plants in July 2011 and issue final standards in May 2012. These standards will impact sources complying with the Clean Smokestacks Act.

VIII. Supplementary Information

Public Staff ─ North Carolina Utilities Commission Audit Reports: As noted in earlier reports, the Public Staff ─ North Carolina Utilities Commission (Public Staff) has audited the books and records of the IOUs with regard to the costs incurred and amortized in compliance with the Act and has filed reports of its findings with the Commission. According to these reports, the Public Staff's audits have confirmed that the costs in question have been incurred in compliance with the Act and have been properly accounted for.

By letter dated May 20, 2008, the Public Staff requested that the Commission confirm that its audit and reporting responsibilities with respect to the costs incurred and amortized by Duke Energy in compliance with the Act have been fulfilled with the filing of its 2008 report; inasmuch as Duke Energy's obligation under the Act, with respect to accelerated amortization, had been completed as of December 31, 2007. By letter dated July 10, 2008, the Commission advised the Public Staff that, in consideration of the foregoing, it was of the opinion that the Public Staff should not need to further monitor and make reports to the Commission regarding Duke Energy's recording of accelerated amortization, per se. The Commission further advised that the Commission was

> . . . also of the opinion that the Public Staff does not need to conduct further regularly scheduled investigations or make further regularly scheduled reports to the Commission relating specifically and exclusively to Duke's compliance with the Act. But rather, the Commission is of the opinion that such investigations should be undertaken and that such

reports should be provided on a case-by-case basis as circumstances and/or events may require.

Progress Energy's obligation under the Act, with respect to accelerated amortization, was completed in June 2008. Consequently, neither IOU recorded accelerated amortization in 2009.

The Public Staff filed its most recent Clean Smokestacks Act report concerning Progress Energy and it also filed certain comments regarding Duke Energy with the Commission on May 12, 2009. Such filings were addressed in DENR and the Commission's 2009 Clean Smokestacks Act joint report.

In its May 12, 2009 cover letter accompanying its 2008 Progress Energy Clean Smokestacks Act report, the Public Staff requested that the Commission ". . . confirm that its audit and reporting responsibilities with respect to costs incurred and amortized by [Progress Energy] in compliance with the Clean Smokestacks Act have been fulfilled with the filing of [the Public Staff's report for 2008]." While the Commission has not responded to that request directly, its expectations regarding any further audits and reports by the Public Staff relating exclusively to compliance with the Act are the same for Progress Energy as they are for Duke Energy.

Estimated 2011 Cost-of-Service Impact of IOUs' Continuing Compliance with the Act: The cost-of-service[1] or, synonymously, the revenue requirement impact of continuing compliance with the Act, for calendar year 2011, for each IOU is estimated to be as follows:

Progress Energy:

● Total company	$117.6 million
● N.C. retail	$82.3 million
● Residential customer monthly bill impact with usage @ 1,000 kWh per month	$2.20
● Residential customer monthly bill with usage @1,000 kWh	$102.19

Duke Energy:

● Total company	$203.8 million
● N.C. retail	$148.2 million
● Residential customer monthly bill impact with usage @ 1,000 kWh per month	$2.71
● Residential customer monthly bill with usage @1,000 kWh	$92.72

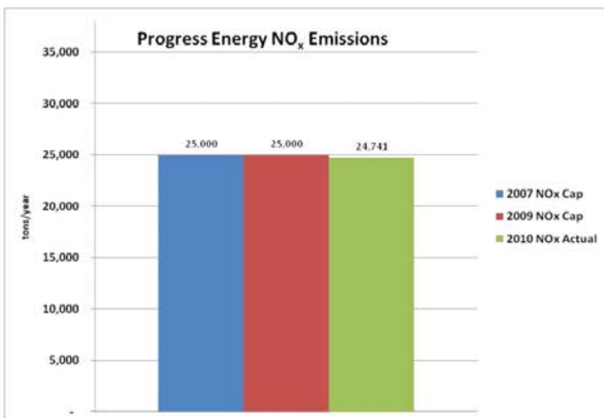
[1] The annual cost of service or, synonymously, annual revenue requirement of an investor-owned public utility, such as Progress Energy and/or Duke Energy, is typically defined as the sum total of reasonable operating expenses, depreciation expense, taxes, and a reasonable return on the net valuation of property.

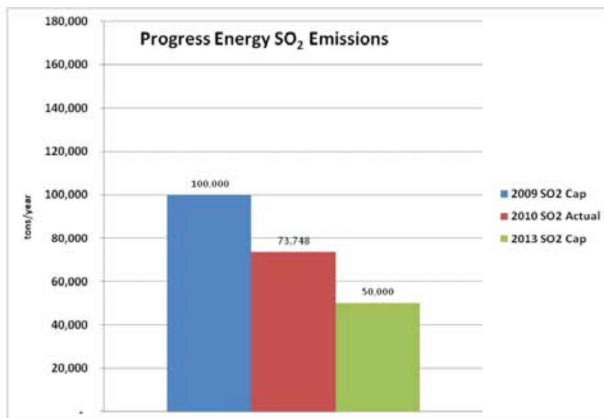
IX. Conclusions

<u>DENR/DAQ</u>

DENR/DAQ carefully reviewed and considered the information provided by Progress Energy and Duke Energy in their April 1 and March 29, 2011, compliance plan submittals, respectively. Both companies continue to meet the emissions limitations as specified in the Act.

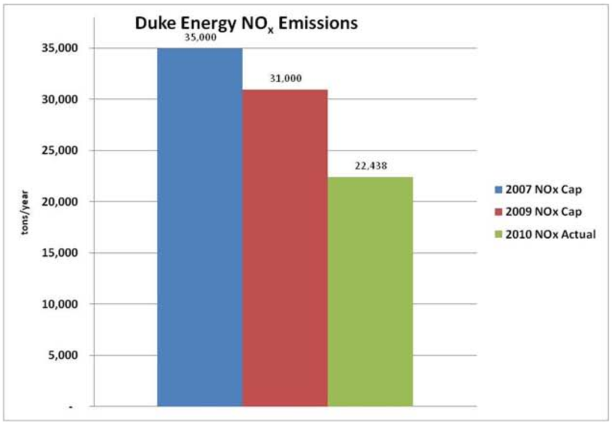
Progress Energy has completed nearly all of the emissions control projects and associated work to assure compliance with the Clean Smokestacks Act. The remaining work and associated expenditures will be completed by the end of 2011. The Company has installed a mix of combustion devices, which minimize the formation of NOx (e.g., low-NOx burners and over-fire air technologies), and post-combustion controls, which reduce NOx produced during the combustion of fossil fuel to molecular nitrogen (e.g., selective catalytic reduction and selective non-catalytic reduction technologies). Progress Energy has continued to meet its 2009 annual emission limit of 25,000 tons NOx. Calendar year 2010 NOx emissions were 24,741 tons (see Figure below):

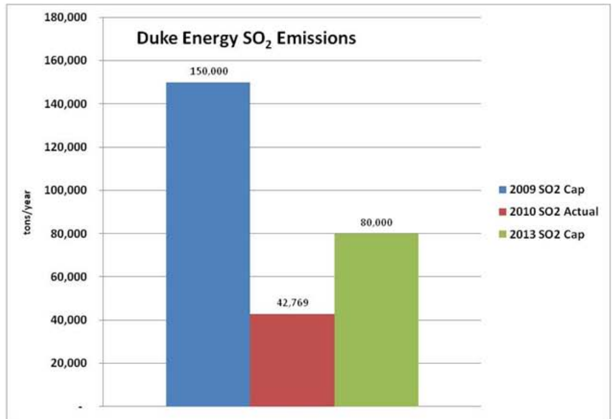




Progress Energy's initial SO_2 control plan included putting scrubbers on eight units. The Company's 2004 SO_2 emissions were 195,655 tons with no scrubbers. Progress Energy has continued to meet its 2009 SO_2 limit of 100,000 tons. Calendar year 2010 SO_2 emissions were 73,748 tons. By 2013, Progress Energy plans to retire the Lee coal-fired plant and replace the plant with a combined-cycle natural gas-fired unit. It is reasonable to conclude that with the annual operation of the two Asheville units, all four Roxboro units, one Mayo unit, and retirement of the three Lee units, Progress Energy is on track to meet its SO_2 limit of 50,000 tons in 2013.

Duke Energy has completed all emissions control projects to assure compliance with the Clean Smokestacks Act. The Company has completed installing controls for NOx reductions, which consists of a combination of selective catalytic reduction and selective non-catalytic reduction technologies, and low NOx burners. Duke Energy has continued to meet its 2009 annual emissions limit of 31,000 tons for NOx. Calendar year 2010 NOx emissions were 22,438 tons (see Figure below):





Duke Energy's SO_2 control plan included installation and operation of 12 scrubbers to meet emissions limits of 150,000 tons in 2009 and 80,000 tons in 2013. Duke Energy has completed installation of wet flue-gas desulfurization scrubbers on all 12 generating units, and all scrubbers were in operation at the end of 2010. These units have so far reduced Duke Energy's SO_2 emissions from 298,781 tons (2005) to 42,769 tons (2010). Duke Energy's SO_2 controls are several years ahead of the planned schedule. The Company has already met its 2013 SO_2 target, and is likely to maintain such emissions levels through continuous operation of the required control systems.

COMMISSION

The Commission has also carefully reviewed and considered the information and data provided by the investor-owned public utilities in their Clean Smokestacks annual reports for calendar year 2010. Based upon those reports and in consideration of DENR's findings, the Commission is also of the opinion that Progress Energy and Duke Energy continue to be in compliance with the Act.

SUMMARY

In summary, DENR and the Commission conclude that the actions taken to date by Progress Energy and Duke Energy are in accordance with the provisions and requirements of the Clean Smokestacks Act. Further, the compliance plans and schedules proposed by Progress Energy and Duke Energy appear adequate to achieve the emissions limitations set out in G.S. 143-215.107D.

Attachments

Attachment A: Duke Energy Carolinas, LLC, *NOx and SO_2 Compliance Plan Annual Update*, Submitted by Cover Letter Dated March 29, 2011

Attachment B: Progress Energy Carolinas, Inc. *Annual NC Clean Smokestacks Act Compliance Report*, Submitted by Cover Letter Dated April 1, 2011

Duke Energy® Carolinas

GEORGE T. EVERETT, Ph.D.
Director
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March 29, 2011

Ms. Renne C. Vance, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

Mr. Dee A. Freeman, Secretary
North Carolina Department of Environment and Natural Resources
1601 Mail Service Center
Raleigh, NC 27699-1601

Subject: Docket No. E-7, Sub 718
Duke Energy Carolinas, LLC
NO_x and SO_2 Compliance Plan Annual Update
Record No: NC CAP 0010

Dear Ms. Vance and Mr. Freeman

Duke Energy Carolinas, LLC is required by Senate Bill 1078 ("North Carolina Clean Air Legislation") to file information on or before April 1 of each year to update the North Carolina Utilities Commission ("Commission") of the progress to date, upcoming activities and expected plans to achieve the emissions limitations set out in G.S. 143-215.107D. Enclosed for filing are the original and thirty (30) copies of Duke Energy Carolinas' Compliance Plan Annual Update for 2011 that fully describe the Company's efforts to comply with the North Carolina Clean Air Legislation.

The current plan to meet the emission requirements for NO_x and SO_2 includes:

NO_x Control – Duke Energy Carolinas has completed installing controls for NO_x reductions originally planned under the North Carolina Clean Air Legislation. The combination of SCR, SNCR, and low NO_x burners, along with year round operation of these controls, has achieved and continues to maintain annual emissions below Duke Energy Carolinas' final annual target of 31,000 tons of NO_x per year.

SO_2 Control – Except for finalizing a small amount of project close-out work, Duke Energy Carolinas has completed installation of wet flue-gas desulfurization scrubbers on our twelve largest generating units. At the end of 2010 all twelve scrubbers were in operation. In 2010, Duke Energy Carolinas operated well below its 2010 SO_2 emission limit of 150,000 tons and well below the 80,000 ton emissions limit that will be applicable beginning in 2013.

Exhibits A and B outline current unit specific technology selections, operational year, expected emission rates and the corresponding tons of emissions that demonstrate compliance with the legislative requirements to the best of Duke Energy Carolinas' knowledge at this time. The current estimate of the costs of these pollution control projects are included in Exhibit C. Duke Energy's current total predicted cost to comply is equivalent to the cost predicted in the 2008 report (NC CAP 007).

Duke Energy Carolinas will continue to examine the technology selection, implementation schedule and associated costs. Annual updates will be provided to the Commission as required. If you have questions regarding any aspect of our plan, please do not hesitate to contact my office at 919-235-0955.

Sincerely,

George T. Everett

George T. Everett
Director, Environmental and Legislative Affairs
Duke Energy Carolinas

Enclosures

xc: Robert P. Gruber
Executive Director – Public Staff

xc: Sheila Holman, Director
North Carolina Division of Air Quality

Duke Energy Carolinas, LLC

General Assembly of North Carolina Session 2001

Senate Bill 1078 – Improve Air Quality/Electric Utilities (NC Clean Air Legislation)

2011 Annual Data Submittal

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1. A detailed report on the investor-owned public utility's plans for meeting the emissions limitations set out in G.S. 143-215.107D.

Exhibits A and B outline the technology selections by facility and unit, actual and projected operational dates, actual and expected emission rates, and the corresponding tons of emissions that demonstrate compliance with the provisions of G.S. 143-215.107D. Changes to the expected plan for meeting these emissions limitations as compared to past compliance plans are:

NO_x Compliance

- Emission Rate Changes – Expected rates for certain units have been adjusted in this 2011 update based on operating experience in 2010 with installed controls, targeted future performance and planned retirements.

SO_2 Compliance

- Emission Rate Changes – Expected rates have been adjusted in this 2011 update based on operating experience in 2010 with installed controls, targeted future performance and planned retirements.

2. The actual environmental compliance costs incurred by the investor-owned public utility in the previous calendar year, including a description of the construction undertaken and completed during that year.

In the 2010 calendar year, Duke Energy Carolinas incurred construction charges of $78,058,000 on activities in support of compliance with the provisions of G.S. 143-215.107D. Exact amounts associated with each project are provided in Exhibit C. A description of the associated activities is provided below:

Allen Steam Station FGD

- Completed final drawing turnover and archival.
- Completed strainer replacement with automatic strainers due to algae issue.

Cliffside Steam Station Unit 5 FGD

- Completed backfeed power to Unit 5 Auxiliary Transformers.
- Completed turnover of the control of the Raw Water Pump Structure and Clarifier to the station.
- Completed upgrade of the Unit-5 Distributed Control System (DCS).
- Completed project mechanical systems.

- Finalized FGD System tie-in to Unit-5.
- Completed FGD System Testing and Tuning.
- Completed FGD System Performance Testing.
- Turned over control of the FGD facility the station.

3. **The amount of the investor-owned public utility's environmental compliance costs amortized in the previous calendar year.**

As discussed in the December 20, 2007 order associated with rates and environmental compliance costs (Docket E-7 Sub 829), no additional amounts were amortized related to construction work activity in the 2010 calendar year in support of compliance with the provisions of G.S. 143-215.107D. **$1,050,000,000** was amortized in total for the program through year-end 2007.

4. **An estimate of the investor-owned public utility's environmental compliance costs and the basis for any revisions of those estimates when compared to the estimates submitted during the previous year.**

The estimated "environmental compliance costs" as defined in G.S. 143-215.107D are provided in Exhibit C. While there has been no significant change to the scope or timing associated with any of these projects, actual charges and forecasts for active projects have been updated as compared to the 2010 filing. The net overall cost is currently predicted to be $1.843 billion and is basically unchanged from the overall cost predicted in the 2008 report.

5. **A description of all permits required in order to comply with the provisions of G.S. 143-215.107D for which the investor-owned public utility has applied and the status of those permits or permit applications.**

<u>Allen Steam Station FGD</u>

- Request to revise NPDES Permit to include FGD wastewater – Submitted 1/24/2006; received revision 9/11/2006
- Authorization to Construct (ATC) application for Wastewater Treatment System – Submitted 9/14/2006; received Permit to Construct 12/15/2006
- Air Permit Application for Allen FGD project Submitted 4/10/2006; received Air Permit 6/30/2006
- Stack contractor applied for air permit associated with flue liner fabrication on 11/1/2006 and received permit on 2/2/2007.
- Landfill Site Suitability Application – Submitted 10/31/07; received 12/7/07
- Landfill Permit to Construct – Submitted 3/25/08; received permit to construct 9/4/2008
- Landfill Supplemental Stability Analysis – Submitted 8/11/09; accepted 12/9/09
- FGD Landfill Permit to Operate – Submitted 11/20/09; granted 12/9/09

- Landfill Permit to Operate Phase 1 cell 2 – Submitted 9/3/10; granted 12/8/10
- Erosion control permits received in 2006 (7/13/2006 and 12/18/2006).
- Submittal to DENR/ACOE regarding stream crossing of entrance road – Received permits 5/25/2006
- Received permit from NCDOT to improve Highway NC273 at the Allen FGD entrance road on 12/3/2008.
- FAA Permit for Stack – Submitted 12/9/05, received permit 1/11/06

Belews Creek Steam Station FGD

- Request to revise NPDES Permit to include FGD wastewater – Submitted 6/30/2004; received Permit Revision 5/16/2005
- Authorization to Construct (ATC) application for Constructed Wetlands – Submitted 7/21/2005; received Permit to Construct 12/27/2005
- Authorization to Construct (ATC) application for Wastewater Treatment System – Submitted 7/21/2005; received Permit to Construct 12/27/2005
- Air Permit Application for Belews Creek FGD project Submitted 4/18/2005; received Air Permit 2/6/2006
- Air Permit – Notice of Intent to Construct – Submitted 10/11/2005; received Permit to Construct 10/24/2005
- Landfill Site Suitability Application – Submitted 3/30/2005; received Site Suitability Approval Letter 6/19/2006
- Revised Landfill Construction Plan Application – Submitted 9/30/2005; received Permit to Construct 6/29/2006
- FGD Landfill Permit to Operate – Submitted 9/28/2007; granted 1/24/2008
- Initial Erosion Control Permit – Submitted 2/4/2005; received Permit 3/7/2005
- Erosion Control Permit to construct Used Oil Building – Submitted August 2008; received permit 10/10/2008
- Revisions to Erosion Control Permit submitted on various dates; most recent revised permit received 3/30/2006
- Authorization to Construct Sanitary Waste Lagoon – Submitted 3/23/2006; received Permit to Construct 9/1/2006
- Existing Sewage Lagoon Approval to Decommission – Submitted 10/31/2006; received permit 1/25/2007
- Building Permit to construct Used Oil Building – Submitted August 2008; received permit 10/21/2008
- FAA Permit for Stack – Submitted 7/22/05, received permit 9/1/05

Cliffside Steam Station Unit 5 FGD

- Request to revise NPDES Permit (including new Cliffside Unit 6) – Submitted 4/30/2007; Received Permit Revision 8/13/2007
- Authorization to Construct (ATC) application for Wastewater Treatment System – received Permit to Construct 9/22/08
- Air Permit Application for Cliffside Unit 5 FGD project
- Submitted 12/16/2005; received Air Permit 12/15/2006

- Air Permit Application for Cliffside Station FGD Project (Common Support Facilities for Units 5&6) - Submitted 12/23/09; received permit 2/3/10.
- Landfill Site Suitability Application – Submitted 1/7/08; received 11/18/08
- Landfill Construction Plan Application – Submitted 12/18/08, received 6/4/09
- FGD Landfill Permit to Operate – Submitted 8/23/10; granted 9/7/10
- Roadway Erosion and Sedimentation Control Plan – Submitted 6/12/09 received 11/3/09
- CCP Landfill Erosion and Sedimentation Control Plan – Submitted 2/2/09, received 3/16/09
- Building Permits from Cleveland & Rutherford Counties for WFGD Control Room – received 1/26/09
- Design Hydrogeologic Report and Water Quality Monitoring Plan – Submitted 7/08, received 6/3/09
- Rutherford County Watershed Protection Plan – Submitted 3/13/09, received 5/14/09
- FAA Permit for Stack – Submitted 8/22/07, received permit 10/30/2007

Marshall Steam Station FGD

- Request to revise NPDES Permit to include FGD wastewater – Submitted 10/27/2004; received Permit Revision 4/25/2005
- Authorization to Construct (ATC) application for Solids Removal System – Submitted 11/19/04; received 12/22/04
- Authorization to Construct (ATC) application for Constructed Wetlands – Submitted 5/21/04; received 8/10/04
- Authorization to Construct (ATC) Vertical Flow Constructed Wetlands – Submitted 2/1/10; received 6/1/10
- Air Permit Application for Marshall FGD project
- Submitted 9/17/2003; received Air Permit 2/5/2004
- Air Permit Revisions (for material handling issues) – Submitted 9/2/05; received approval 12/7/05
- Landfill Construction Plan Application – Submitted 4/1/04; received 2/4/05
- Landfill Permit Documents (to line landfill) – Submitted 12/15/05; received 6/5/06
- FGD Landfill Permit to Operate – Submitted 10/27/06; granted 11/21/06"
- Sedimentation and Erosion Control Plan Permits for Gypsum Landfill – Submitted 3/31/04; received 4/21/04
- Sedimentation and Erosion Control Plan Permits for Constructed Wetland Treatment System – Submitted 7/26/04; received 8/18/04
- Sedimentation and Erosion Control Plan Permits for Limestone/Gypsum Conveyor – Submitted 6/17/04; received 7/9/04 For Conveyor Expansion – Submitted 12/15/04; received 12/30/04
- FAA Permit for Stack – Submitted 5/3/04, received permit 6/10/04

Allen Steam Station SNCRs, Unit 2 and Unit 5

- Air Permit Application – Submitted 4/24/06; Received 6/30/06

Allen Steam Station SNCR, Unit 3

- Air Permit Application – Submitted 7/15/04; Received 2/5/05

Allen Steam Station SNCR, Unit 4

- Air Permit Application – Submitted 7/15/05; Received 1/15/06
- Building/Plumbing permit from Gaston County Building and Standards – Received 4/27/06 for municipal water tie-ins.

Buck Steam Station Burners, Unit 3 and Unit 4

- Air Permit Application – Submitted 9/15/06; Received 2/15/07

Buck Steam Station SNCR, Unit 5 and Unit 6

- Air Permit Application – Submitted 3/10/06; Received 5/16/06

Dan River Steam Station Burners, Unit 1, Unit 2 and Unit 3

- Air Permit Application – Submitted 2/23/06; Received 9/11/06

Marshall Steam Station SNCRs, Unit 1 and Unit 2

- Air Permit Application – Submitted 9/18/05; Received 12/20/05

Marshall Steam Station SNCR, Unit 3

- Air Permit Application – Submitted 5/14/04; Received 10/13/04

Marshall Steam Station SNCR, Unit 4

- Air Permit Application – Submitted 4/28/06; Received 9/12/06

Riverbend Steam Station SNCRs, Unit 4 and Unit 5

- Air Permit Application – Submitted 3/20/05; Received 8/1/05

Riverbend Steam Station Burners, Unit 5

- Air Permit Application – Submitted 4/2/04; Received 4/30/04

Riverbend Steam Station Burners, Unit 6

- Air Permit Application – Submitted 5/14/03; Received 9/30/03

Riverbend Steam Station SNCRs, Unit 6 and Unit 7

- Air Permit Application – Submitted 11/5/05; Received 1/1/06

6. **A description of the construction related to compliance with the provisions of G.S. 143-215.107D that is anticipated during the following year.**

Allen Steam Station FGD

- Complete installation of additional relays to eliminate reliability issue with Belmont Tie.
- Perform Absorber vessel corrosion analysis, including third party review of corrosion issues discovered during equipment inspections.

Cliffside Steam Station Unit 5 FGD

- Complete punchlist and closeout activities.
- Complete installation of 230kV Breakers on FGD Aux Transformer.
- Achieve final completion.

7. A description of the applications for permits required in order to comply with the provisions of G.S. 143-215.107D that are anticipated during the following year.

No additional applications for permits are expected.

8. The results of equipment testing related to compliance with G.S. 143-215.107D.

Cliffside Steam Station FGD, Unit 5

- The Cliffside 5 FGD System was commissioned in 2010 and a Performance Test was conducted on November 18-19, 2010. The Performance Test results reported by the Testing Contractor indicated the FGD System's SO_2 removal efficiency achieved its performance guarantee of 99%.

The SNCR and SCR tests that occurred in prior years that were used in evaluating technology selections are repeated in this report for reference.

Allen Steam Station SNCR, Unit 1

- SNCR Equipment installation was completed in May 2003 followed by equipment acceptance testing in late 2003. During this test run, it was determined that the SNCR system met all commercial performance guarantees with approximately a 25% reduction in NOx with ammonia slip of less than 5 ppm at full load.

Belews Creek Steam Station SCR

- SCR Equipment installation was completed in 2003. Tests performed during the months of August and September 2004 showed that when the SCR equipment was in service during this time, emissions of NOx averaged 0.07lb/mmBtu.

9. The number of tons of oxides of nitrogen (NO_x) and sulfur dioxide (SO_2) emitted during the previous calendar year from the coal-fired generating units that are subject to the emissions limitations set out in G.S. 143-215.107D.

In the 2010 calendar year, 22,438 tons of NO_x and 42,769 tons of SO_2 were emitted from the Duke Energy Carolinas coal-fired units located in North Carolina and subject to the emissions limitations set out in G.S 143-215.107D.

10. The emissions allowances described in G.S. 143-215.107D(i) that are acquired by the investor-owned public utility that result from compliance with the emissions limitations set out in G.S. 143-215.107D.

In order to comply with the June 21, 2002 Agreement Under Seal, on 2/14/2011, Duke Energy Carolinas surrendered to the state of North Carolina 28,492 SO2 allowances and 1,958 Annual NOx allowances for compliance year 2009. The agreement calls for the surrender of all allowances allocated by US EPA that are in excess of the limits in this Legislation. For 2009 those limits were 150,000 SO2 Tons and 31,000 NOx Tons.

11. Any other information requested by the Commission or Department of Environment and Natural Resources.

No additional information has been requested to be included in this annual data submittal.

Duke Energy Carolinas Compliance for NC Clean Air Legislation as of 4/1/2011
(Exhibit A)

NO_x				2010		2011 Predicted		2013 Predicted	
Facility	Unit or Boiler	Technology	Initial Operational Year	**Actual** Rate #/MMBTUs	Tons	**Expected** Rate #/MMBTUs	Tons	**Expected** Rate #/MMBTUs	Tons
Allen	1	SNCR	2003	0.193	665	0.18	622	0.18	237
Allen	2	SNCR	2007	0.193	597	0.17	428	0.17	137
Allen	3	SNCR	2005	0.188	1,240	0.17	1,211	0.18	664
Allen	4	SNCR	2006	0.187	1,256	0.18	1,384	0.18	924
Allen	5	SNCR	2008	0.195	1,288	0.18	1,281	0.18	671
Belews Creek	1	SCR	2003	0.055	1,851	0.06	2,048	0.06	1,889
Belews Creek	2	SCR&Burners	2004	0.056	1,420	0.06	2,354	0.06	2,336
Buck	5	Burners	2007	0.220	57				
Buck	6	Burners	2007	0.237	67				
Buck	7	Burners	2007	0.322	97				
Buck	8	SNCR	2006	0.175	448	0.16	251	0.16	71
Buck	9	SNCR	2006	0.188	477	0.17	175	0.17	20
Cliffside	1	Tuning Only	2004	0.481	26				
Cliffside	2	Tuning Only	2004	0.405	24				
Cliffside	3	Tuning Only	2004	0.369	46				
Cliffside	4	Tuning Only	2004	0.364	42				
Cliffside	5	SCR	2002	0.072	726	0.06	870	0.06	540
Cliffside	6	SCR	2012					0.05	1,008
Dan River	1	Burners	2008	0.353	196	0.25	0		-
Dan River	2	Burners	2006	0.382	200	0.25	0		-
Dan River	3	Burners	2006	0.314	571	0.19	256		-
Marshall	1	SNCR	2006	0.204	1,953	0.21	1,924	0.21	1,821
Marshall	2	SNCR	2007	0.203	1,771	0.20	2,117	0.20	1,666
Marshall	3	SNCR/SCR[1]	2005/2008	0.047	926	0.06	1,205	0.06	935
Marshall	4	SNCR	2007	0.213	4,959	0.19	3,974	0.19	3,660
Riverbend	7	SNCR	2007	0.277	327	0.20	2	0.20	0
Riverbend	8	SNCR&Burners	2008	0.291	289	0.18	1		-
Riverbend	9	SNCR&Burners	2006	0.263	431	0.19	18	0.19	2
Riverbend	10	SNCR	2006	0.266	492	0.19	24	0.20	2
		NC Coal Fleet Expected/Actual Total:			22,438		20,145		16,585
		Compliance Limit:			31,000		31,000		31,000

Duke Energy Carolinas Compliance for NC Clean Air Legislation as of 4/1/2011
(Exhibit B)

SO_2									
				2010		2011 Predicted		2013 Predicted	
Facility	Unit or Boiler	Technology	Initial Operational Year	Actual Rate #/MMBTUs	Tons	Expected Rate #/MMBTUs	Tons	Expected Rate #/MMBTUs	Tons
Allen	1	Scrubber	2009	0.083	296	0.12	411	0.11	141
Allen	2	Scrubber	2009	0.084	272	0.12	298	0.11	86
Allen	3	Scrubber	2009	0.074	489	0.12	814	0.11	399
Allen	4	Scrubber	2009	0.072	484	0.12	904	0.11	541
Allen	5	Scrubber	2009	0.077	530	0.12	836	0.11	397
Belews Creek	1	Scrubber	2008	0.057	2,102	0.09	3,084	0.08	2,529
Belews Creek	2	Scrubber	2008	0.052	1,523	0.09	3,537	0.08	3,120
Buck	5			1.120	259				
Buck	6			1.139	309				
Buck	7			1.119	322				
Buck	8			1.115	2,834	1.42	2,196	1.44	625
Buck	9			1.102	2,776	1.43	1,498	1.45	173
Cliffside	1			1.558	82				
Cliffside	2			1.585	92				
Cliffside	3			1.504	178				
Cliffside	4			1.486	162				
Cliffside	5	Scrubber	2010	0.992	11,703	0.10	1,473	0.12	1,111
Cliffside	6	Scrubber	2012					0.06	1,381
Dan River	1			1.252	762	1.43	1		-
Dan River	2			1.243	762	1.43	1		-
Dan River	3			1.267	2,767	1.42	1,869		-
Marshall	1	Scrubber	2007	0.065	608	0.15	1,348	0.16	1,431
Marshall	2	Scrubber	2007	0.067	568	0.15	1,533	0.16	1,367
Marshall	3	Scrubber	2007	0.056	1,163	0.15	2,922	0.16	2,522
Marshall	4	Scrubber	2006	0.058	1,319	0.15	2,988	0.16	3,118
Riverbend	4			1.508	1,997	1.63	18		3
Riverbend	5			1.542	1,904		6		-
Riverbend	6			1.560	3,170	1.62	156	1.65	18
Riverbend	7			1.538	3,336	1.62	200	1.64	20
NC Coal Fleet Expected/Actual Total:					42,769		26,093		18,985
Compliance Limit:					150,000		150,000		80,000

Duke Energy Carolinas Compliance Costs for NC Clean Air Legislation as of 4/1/2011
(Exhibit C)

Facility	Unit(s)	Technology	Operational Date	Spent to Date 2001-'03 ($000)	Spent to Date 2004 ($000)	Spent to Date 2005 ($000)	Spent to Date 2006 ($000)	Spent to Date 2007 ($000)	Spent to Date 2008 ($000)	Spent to Date 2009 ($000)	Spent to Date 2010 ($000)	Remaining 2011-2012 ($000)	Project Total ($000)	
Allen	1-5	Scrubber	2009	$1,100	($12)	$5,348	$62,753	$209,063	$153,698	$51,765	($1,385)	$157	$482,487	SO_2
Belews Creek	1-2	Scrubber	2008	$1,121	$5,999	$106,434	$250,648	$128,058	$34,629	$1,338	($0.3)	$0	$528,227	
Cliffside	5	Scrubber	2010	$978	$287	$112	$3,175	$57,778	$77,525	$96,111	$79,671	$6,658	$322,296	
Marshall	1-4	Scrubber	2007	$10,214	$92,096	$218,130	$74,163	$23,632	($1,250)	$0	($228)	$0	$416,757	
Allen	1	SNCR	2003	$3,224	$365	$0	$0	$0	$0	$0	$0	$0	$3,589	NO_x
Allen	2	SNCR	2007	$0	$0	$239	$2,711	$2,332	($208)	$0	$0	$0	$5,074	
Allen	3	SNCR	2005	$216	$2,584	$4,092	$32	$0	$0	$0	$0	$0	$6,924	
Allen	4	SNCR	2006	$0	$218	$1,122	$4,258	$171	$16	$0	$0	$0	$5,785	
Allen	5	SNCR	2008	$99	$165	$122	$23	$2,161	$2,425	$0	$0	$0	$4,994	
Buck	3	Burner	2007	$0	$0	$0	$615	$3,565	$0	$0	$0	$0	$4,179	
Buck	3	Classifier	2007	$0	$0	$0	$0	$216	$0	$0	$0	$0	$216	
Buck	4	Burner	2007	$0	$0	$0	$358	$1,882	$1	$0	$0	$0	$2,241	
Buck	4	Classifier	2007	$0	$0	$0	$0	$93	$0	$0	$0	$0	$93	
Buck	5	SNCR	2006	$0	$268	$346	$4,837	$183	$160	$0	$0	$0	$5,794	
Buck	6	SNCR	2006	$0	$266	$335	$3,814	($685)	($29)	($2)	$0	$0	$3,699	
Dan River	1	Burner	2008	$0	$0	$0	$0	$1,560	$1,633	$0	$0	$0	$3,194	
Dan River	1	Classifier	2008	$0	$0	$0	$0	$124	$0	$0	$0	$0	$124	
Dan River	2	Burner	2006	$0	$0	$775	$1,694	$239	$0	$0	$0	$0	$2,708	
Dan River	2	Classifier	2005	$0	$0	$131	$0	$0	$0	$0	$0	$0	$131	
Dan River	3	Burner	2006	$192	$513	$679	$1,441	$377	$0	$0	$0	$0	$3,202	
Dan River	3	Classifier	2005	$0	$0	$184	$0	$0	$0	$0	$0	$0	$184	
Marshall	1	SNCR	2006	$1	$167	$1,418	$2,106	$182	$0	$0	$0	$0	$3,874	
Marshall	2	SNCR	2007	$198	$185	$778	$2,761	$1,382	$322	$0	$0	$0	$5,626	
Marshall	3	SNCR	2005	$1,577	$652	$2,042	$32	$0	$0	$0	$0	$0	$4,304	
Marshall	4	SNCR	2007	$0	$0	$43	$2,614	$494	$0	$0	$0	$0	$3,151	
Riverbend	4	SNCR	2007	$0	$46	$474	$1,082	$1,982	($53)	$0	$0	$0	$3,531	
Riverbend	5	Burner	2005	$650	$2,313	$180	$0	$0	$0	$0	$0	$0	$3,143	
Riverbend	5	Classifier	2005	$0	$160	$0	$0	$0	$0	$0	$0	$0	$160	
Riverbend	5	SNCR	2008	$0	$2	$322	$1,475	$2,587	$6	$0	$0	$0	$4,390	
Riverbend	6	Burner	2005	$572	$510	$2,096	$0	$0	$0	$0	$0	$0	$3,179	
Riverbend	6	Classifier	2005	$0	$0	$189	$0	$0	$0	$0	$0	$0	$189	
Riverbend	6	SNCR	2006	$0	$2	$340	$3,454	$504	$4	$0	$0	$0	$4,304	
Riverbend	7	SNCR	2006	$0	$48	$486	$3,939	$521	$5	$0	$0	$0	$4,999	
			Subtotals:	$20,142	$106,834	$346,420	$427,984	$438,400	$268,884	$149,211	$78,058	$6,815		
												NC Clean Air Legislation program forecast [1]:	$1,842,749	

[1] The NC Clean Air Legislation program forecast excludes all financing-related accounting entries

VERIFICATION

I, George T. Everett, state and attest that the attached information updating the North Carolina Utilities Commission on progress to date, upcoming activities and expected strategies to achieve the emissions limitations set out in N.C.G.S. 143-215.107.D is filed on behalf of Duke Energy Carolinas, LLC. I have reviewed said Annual Update, and in the exercise of due diligence have made reasonable inquiry into the accuracy of the information provided therein; and that, to the best of my knowledge, information, and belief, all of the information contained therein is accurate and true and no material information or fact has been knowingly omitted or misstated therein.

George T. Everett

George T. Everett
Director, Environmental and Legislative Affairs
Duke Energy Carolinas

3/29/2011
Date

Subscribed and sworn to before me,
This 29th day of March, 2011.

Maria Edwards
NOTARY PUBLIC

MARIA EDWARDS NOTARY PUBLIC WAKE COUNTY, NC

My commission expires: 3/2/2013

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's NOx and SO2 Compliance Plan Annual Update in No. E-7, Sub 718, has been served by electronic mail, hand delivery or by depositing a copy in the Unites States Mail, first class postage prepaid, properly addressed to parties of record.

George T. Everett

George T. Everett
Director, Environmental and Legislative Affairs
Duke Energy Carolinas

3/29/2011

Date

George T. Everett
Director, Environmental and Legislative Affairs
Duke Energy Carolinas

Progress Energy

April 1, 2011

Ms. Renne Vance
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

Re: Annual NC Clean Smokestacks Act Compliance Report
Docket No. E-2, Sub 815

Dear Ms. Vance:

Progress Energy Carolinas, Inc. submits the attached report for calendar year 2010 regarding the status of compliance with the provisions of the North Carolina Clean Smokestacks Act. Section 9(i) of the Act requires that an annual report of compliance progress be submitted to the Commission by April 1 of each year for the previous calendar year.

Very truly yours,

Len S. Anthony
General Counsel
Progress Energy Carolinas, Inc.

LSA:mhm

Attachment

STAREG940

Progress Energy Service Company, LLC
P.O. Box 1551
Raleigh, NC 27602

VERIFICATION

STATE OF NORTH CAROLINA)
)
COUNTY OF WAKE)

NOW, BEFORE ME, the undersigned, personally came and appeared, Charles Gates, who first duly sworn by me, did depose and say:

That he is Charles Gates, Vice President-Power Generation of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; he has the authority to verify the foregoing Progress Energy Carolinas, Inc. North Carolina Clean Smokestacks Act Calendar Year 2010 Progress Report; that he has read said revised Report and knows the contents thereof; are true and correct to the best of his knowledge and belief.

Charles Gates

Charles Gates
Vice President-Power Generation
Progress Energy Carolinas, Inc.

Subscribed and sworn to me
this 1st day of ~~March~~ April, 2011.

Kimberley C. Cross

Notary Public
Kimberley C. Cross
My Comm. Exp: Oct 25, 2012

Progress Energy

April 1, 2011

Mr. Dee Freeman, Secretary
North Carolina Department of Environment and Natural Resources
1601 Mail Service Center
Raleigh, NC 27699-1601

Dear ~~Secretary Freeman~~: Dee

Progress Energy Carolinas, Inc. (PEC, Company) submits the attached report for calendar year 2010 regarding the status of its compliance with the provisions of the North Carolina Clean Smokestacks Act (Act).

During 2010, the Company's annual NOx emissions from its North Carolina coal-fired units again totaled less than 25,000 tons, and our SO_2 emissions totaled less than 100,000 tons. We have developed plans and processes to assure that we continue to meet the requirements of the Act while balancing operational flexibility, unit performance, and cost.

As the report shows, PEC has completed nearly all of the emissions control projects and associated work undertaken to assure compliance with the Act. The remaining work and associated expenditures will be completed this year. As discussed in our 2010 report, the Lee coal-fired plant will be retired by 2013, providing additional compliance assurance with the Act's 2013 emissions cap.

We appreciate the excellent work of the Department staff, particularly those in the Air Quality and Water Quality divisions, who have supported our efforts to complete the projects in a timely manner to assure we meet the Act's requirements.

Please contact me at (919) 546-3775 if you have any questions.

Sincerely,

Caroline Choi
Executive Director, Environmental Services and Strategy

c: North Carolina Utilities Commission
Sheila Holman, DAQ

Progress Energy Carolinas, Inc.
P.O. Box 1551
Raleigh, NC 27602

Progress Energy Carolinas, Inc. (PEC)
North Carolina Clean Smokestacks Act
Calendar Year 2010 Progress Report

On June 20, 2002, North Carolina Senate Bill 1078, also known as the "Clean Smokestacks Act," was signed into effect. This law requires significant reductions in the emissions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) from utility owned coal-fired power plants located in North Carolina. Section 9(i), which is now incorporated as Section 62-133.6(i) of the North Carolina General Statutes, requires that an annual progress report regarding compliance with the Clean Smokestacks Act be submitted on or before April 1 of each year. The report must contain the following elements, taken verbatim from the statute:

1. A detailed report on the investor-owned public utility's plans for meeting the emissions limitations set out in G.S. 143-215.107D.
2. The actual environmental compliance costs incurred by the investor-owned public utility in the previous calendar year, including a description of the construction undertaken and completed that year.
3. The amount of the investor-owned public utility's environmental compliance costs amortized in the previous calendar year.
4. An estimate of the investor-owned public utility's environmental compliance costs and the basis for any revisions of those estimates when compared to the estimates submitted during the previous year.
5. A description of all permits required in order to comply with the provisions of G.S. 143-215.107D for which the investor-owned public utility has applied and the status of those permits or permit applications.
6. A description of the construction related to compliance with the provisions of G.S. 143-215.107D that is anticipated during the following year.
7. A description of the applications for permits required in order to comply with the provisions of G.S. 143-215.107D that are anticipated during the following year.
8. The results of equipment testing related to compliance with G.S. 143-215.107D.
9. The number of tons of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emitted during the previous calendar year from the coal-fired generating units that are subject to the emissions limitations set out in G.S. 143-215.107D.
10. The emissions allowances described in G.S. 143-215.107D(i) that are acquired by the investor-owned public utility that result from compliance with the emissions limitations set out in G.S. 143-215.107D.
11. Any other information requested by the Commission or the Department of Environment and Natural Resources.

Information responsive to each of these report elements follows. The responses are given by item number in the order in which they are presented above.

1. A detailed report on the investor-owned public utility's plans for meeting the emissions limitations set out in G.S. 143-215.107D.

Under G.S. § 143-215.107D(f), "each investor-owned public utility…may determine how it will achieve the collective emissions limitations imposed by this section." PEC originally submitted its compliance plan on July 29, 2002. Appendix A contains an updated version of this plan, effective April 1, 2010.

2. The actual environmental compliance costs incurred by the investor-owned public utility in the previous calendar year, including a description of the construction undertaken and completed that year.

In 2010, PEC incurred actual capital costs of $5,264,000.

<u>Roxboro</u>

Construction related to remediation work on the waste water treatment settling ponds continued during 2010.

3. The amount of the investor-owned public utility's environmental compliance costs amortized in the previous calendar year.

The Company amortized $0 in 2010. No additional amortization is anticipated.

4. An estimate of the investor-owned public utility's environmental compliance costs and the basis for any revisions of those estimates when compared to the estimates submitted during the previous year.

Appendix B contains the capital costs incurred toward compliance with G.S. § 143-215.107D through 2010 and the projected costs for future years through 2013. The costs shown are the net costs to PEC, excluding the portion for which the Power Agency is responsible. The estimated total capital costs, including escalation, are currently projected to be $1.056 billion. This represents a decrease of $4 million from the April 2010 cost estimate of $1.060 billion.

5. A description of all permits required in order to comply with the provisions of G.S. 143-215.107D for which the investor-owned public utility has applied and the status of those permits or permit applications.

PEC has completed the permitting required to comply with the provisions of G.S. 143-215.107D. The Company applied for and/or received the following permits in 2010:

<u>Roxboro Plant</u>

Erosion and Sediment Control Plan

An Erosion and Sediment Control Plan revision for an increase in disturbed land for a Construction Borrow area for the Waste Water Treatment Ponds was submitted on March 17, 2010 and approved on March 19, 2010. This Erosion and Sediment Control Plan was closed as documented in the Sedimentation Inspection Report submitted on September 28, 2010.

Dam Safety Submittals

An application for certificate of approval for construction of the new East Gypsum settling pond was submitted to the Division of Land Resources on April 28, 2010. Final approval to impound the new East Settling Pond was received from the Division of Land Resources on November 17, 2010.

Applications for a certificate of approval for repair of the West Gypsum settling pond were submitted to the Division of Land Resources on June 8, 2010 and September 27, 2010. Approval from the Division of Land Resources was received dated November 17, 2010.

6. A description of the construction related to compliance with the provisions of G.S. 143-215.107D that is anticipated during the following year.

<u>Roxboro</u>

During 2011, work on the settling ponds will continue through their anticipated completion in the 3rd quarter. There is no further construction anticipated.

7. A description of the applications for permits required in order to comply with the provisions of G.S. 143-215.107D that are anticipated during the following year.

PEC has completed the permitting required to comply with the provisions of G.S. 143-215.107D. The following approval application is anticipated in 2011:

<u>Roxboro Plant</u>

Dam Safety Submittals

Approval to impound the repaired West Settling Pond is expected to be requested from the Division of Land Resources in the second quarter of 2011.

8. The results of equipment testing related to compliance with G.S. 143-215.107D.

No additional equipment testing related to compliance with G.S. 143-215.107D was performed in 2010.

9. The number of tons of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emitted during the previous calendar year from the coal-fired generating units that are subject to the emissions limitations set out in G.S. 143-215.107D.

The affected coal-fired PEC units have achieved a combined 68% reduction in NOx and a 71% reduction in SO_2 since 2002. The total calendar year 2010 emissions from the affected coal-fired PEC units are:

NOx	24,741 tons
SO_2	73,748 tons

10. The emissions allowances described in G.S. 143-215.107D(i) that are acquired by the investor-owned public utility that result from compliance with the emissions limitations set out in G.S. 143-215.107D.

During 2010, PEC did not acquire any allowances as a result of compliance with the emission limitations set out in N.C. General Statute 143-215.107D.

11. Any other information requested by the Commission or the Department of Environment and Natural Resources.

There have been no additional requests for information from the North Carolina Utilities Commission or the Department of Environment and Natural Resources since the last report.

Appendix A

Progress Energy Carolinas, Inc's (PEC) Air Quality Improvement Plan Supplement

April 1, 2010

On June 20, 2002, Governor Easley signed into law SB1078, which caps emissions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) from utility owned coal-fired power plants located in North Carolina. Under the law, G.S. § 143-215.107D, PEC's annual NOx emissions must not exceed 25,000 tons beginning in 2007 and annual SO_2 emissions must not exceed 100,000 tons beginning in 2009 and 50,000 tons beginning in 2013. These caps represent a 56% reduction in NOx emissions from 2002 levels and a 74% reduction in SO_2 emissions from 2002 levels for PEC.

PEC owns and operates 18 coal-fired units at seven plants in North Carolina. The locations of these plants are shown on Attachment 1. Under G.S. § 143-215.107D(f), "each investor-owned public utility...may determine how it will achieve the collective emissions limitations imposed by this section."

Nitrogen Oxides Emissions Control Plan

PEC installed NOx emissions controls on its coal-fired power plants beginning in 1995 in order to comply with Title IV of the Clean Air Act and the NOx SIP Call rule adopted by the Environmental Management Commission (EMC). Substantial NOx emissions reductions have been achieved (24,741 tons of NOx in 2010 compared with 112,000 tons in 1997), and compliance with the Clean Smokestacks Act's 25,000 ton cap has been achieved each year since the cap became effective in 2007. This target was achieved with a mix of combustion controls (which minimize the formation of NOx), such as low-NOx burners and over-fire air technologies, and post-combustion controls (which reduce NOx produced during the combustion of fossil fuel to molecular nitrogen), such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies.

Attachment 2 details PEC's North Carolina coal-fired electric generating units, their summer net generation capability, and installed NOx control technologies.

Sulfur Dioxide Emissions Control Plan

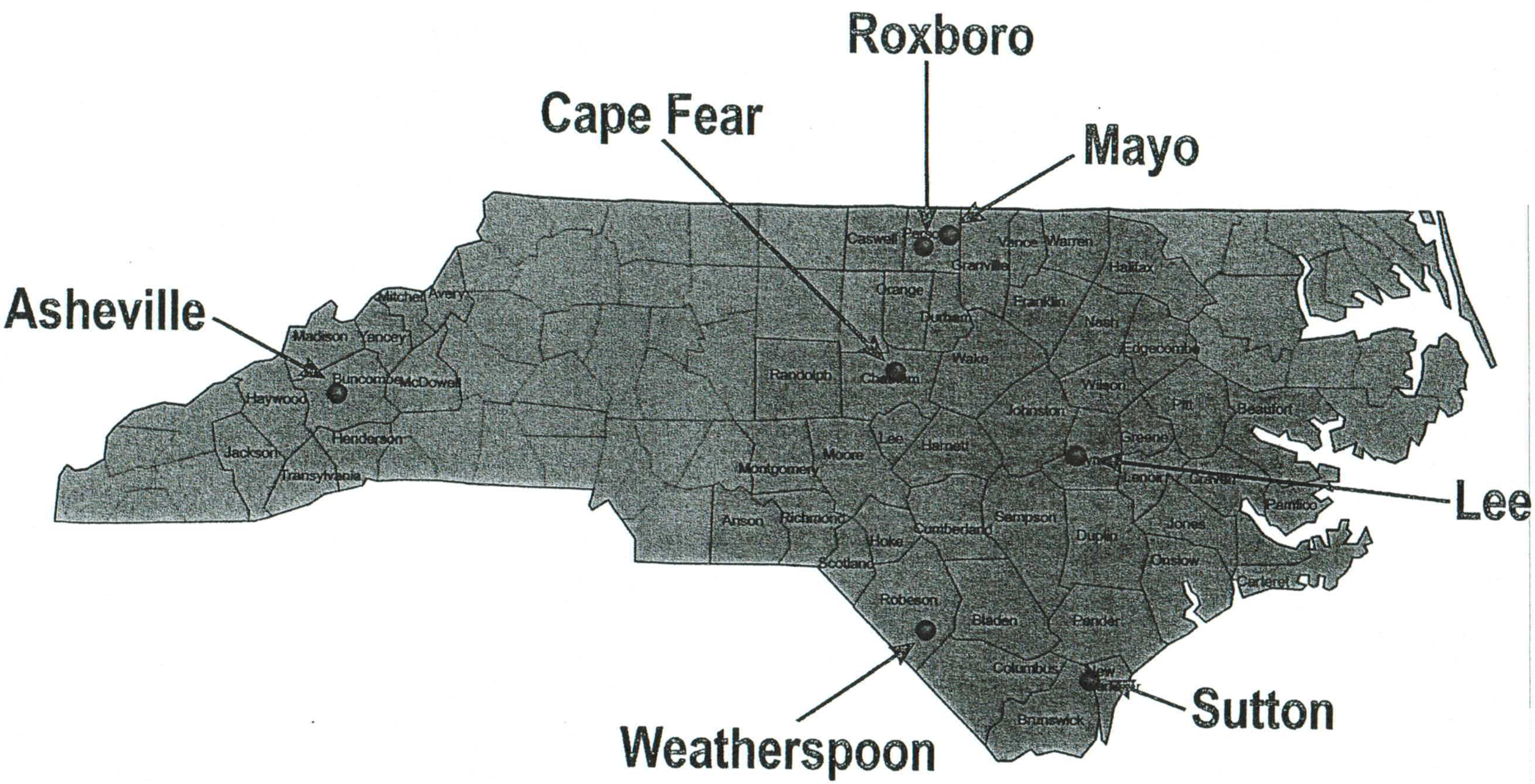
PEC has installed wet flue gas desulfurization systems (FGD or "scrubbers") to remove 97% of the SO_2 from the flue gas at its Asheville, Mayo and Roxboro boilers.

Wet scrubbers produce unique waste and byproduct streams. Issues related to wastewater permitting and solid waste disposal are being addressed for each site accordingly.

PEC has determined that retirement of the Lee coal-fired plant and replacement of that plant with a combined-cycle natural gas-fired unit represents a cost-effective resource plan for our system. Accomplishing this retirement and replacement by 2013 eliminates the need for additional scrubbers in order to comply with the 2013 Clean Smokestacks Act limits.

Attachment 3 details PEC's North Carolina coal-fired electric generating units, their summer net generation capability and installed SO_2 control technologies. Attachment 3 also projects annual SO_2 emissions on a unit-by-unit basis based on the energy demand forecast and expected efficiencies of the SO_2 emissions controls employed. These projections are based on the planned removal technologies and PEC's current fuel and operating forecasts. This information is provided only to show how compliance may be achieved and is not intended in any way to suggest unit-specific emission limits. Actual emissions for each unit may be substantially different.

Attachment 1: Location of PEC's Coal-Fired Power Plants in North Carolina



Attachment 2: PEC's NOx Control Plan for North Carolina Coal-fired Units

Unit	MW Rating	Control Technology	Operation Date[1]
Asheville 1	191	LNB/AEFLGR/**SCR**	2007
Asheville 2	185	LNB/OFA/SCR	
Cape Fear 5	144	ROFA/ROTAMIX	
Cape Fear 6	172	ROFA/ROTAMIX	
Lee 1	74	WIR	
Lee 2	77	**LNB**	2006
Lee 3	246	LNB/**ROTAMIX**	2007
Mayo 1	727	LNB/OFA/SCR	
Roxboro 1	369	LNB/OFA/SCR	
Roxboro 2	662	TFS2000/SCR	
Roxboro 3	693	LNB/OFA/SCR	
Roxboro 4	698	LNB/OFA/SCR	
Sutton 1	97	SAS	
Sutton 2	104	**LNB**	2006
Sutton 3	403	LNB/ROFA/ROTAMIX	
Weatherspoon 1	48		
Weatherspoon 2	48		
Weatherspoon 3	75	WIR	
Total	5,013		

AEFLGR – Amine-Enhanced Flue Lean Gas Reburn
LNB = Low NOx Burner
SCR = Selective Catalytic Reduction
OFA = Overfire Air
ROFA = Rotating Opposed-fired Air
ROTAMIX = Injection of urea to further reduce NOx
WIR = Underfire Air
TFS2000 = Combination Low-NOx Burner/Overfire Air
SAS = Separated Air Staging

[1] This is the operation date for the control technology installed to comply with the North Carolina Clean Smokestacks Act only (shown in bold).

Attachment 3: PEC's SO_2 Control Plan for North Carolina Coal-Fired Units

Unit	MW Rating	Technology	Operation Date		Projected SO_2 Tons, 2013
Asheville 1	191	Scrubber	2005		210
Asheville 2	185	Scrubber	2006		208
Cape Fear 5	144				2,148
Cape Fear 6	172				2,001
Lee 1	74				
Lee 2	77				
Lee 3	246				
Mayo 1	727	Scrubber	2009		2,279
Roxboro 1	369	Scrubber	2008		604
Roxboro 2	662	Scrubber	2007		1,099
Roxboro 3	693	Scrubber	2008		1,051
Roxboro 4	698	Scrubber	2007		811
Sutton 1	97				1,253
Sutton 2	104				2,193
Sutton 3	403				12,806
Weatherspoon 1	48				
Weatherspoon 2	48				
Weatherspoon 3	75				
Total	5,013				26,663

[1] Unit by unit emissions are illustrative only and specific emissions limits should not be inferred. Actual emissions in 2013 may be different from unit to unit.

Appendix B
PEC Actual Costs Through 2010 and Projected Costs Through 2013
PGN Financial View Cost Net of Power Agency Reimbursement (in thousands)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Asheville 1 FGD	$ 100	$ 9,652	$ 33,574	$ 35,769	$ 3,930	-$ 1,850	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 81,175
Asheville 1 SCR	$ 0	$ 0	$ 688	$ 1,423	$ 14,608	$ 11,942	-$ 262	$ 0	$ 0	$ 0	$ 0	$ 0	$ 28,400
Asheville 2 FGD	$ 100	$ 7,742	$ 28,390	$ 24,238	$ 11,701	-$ 1,543	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 70,629
Asheville FGD Common	$ 467	$ 0	$ 0	$ 0	$ 0	-$ 479	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	-$ 12
Mayo 1 FGD	$ 187	$ 0	$ 276	$ 644	$ 22,794	$ 104,886	$ 67,703	$ 23,799	$ 108	$ 0	$ 0	$ 0	$ 220,396
Roxboro FGD Common	-$ 15	$ 5,560	$ 10,030	$ 51,717	$ 72,934	$ 36,491	-$ 1,360	$ 2,717	$ 4	$ 0	$ 0	$ 0	$ 178,078
Roxboro 1 FGD	$ 434	$ 0	$ 0	$ 3,135	$ 12,164	$ 32,841	$ 24,905	$ 1,181	-$200	$ 0	$ 0	$ 0	$ 74,459
Roxboro 2 FGD	$ 120	$ 3,574	$ 6,848	$ 30,782	$ 46,014	$ 18,975	-$ 357	$ 0	$ 0	$ 0	$ 0	$ 0	$ 105,955
Roxboro 3 FGD	$ 0	$ 0	$ 244	$ 10,628	$ 36,661	$ 49,985	$ 9,006	$ 255	$ 0	$ 0	$ 0	$ 0	$ 106,779
Roxboro 4 FGD	$ 0	$ 0	$ 0	$ 9,074	$ 28,550	$ 57,610	$ 1,876	$ 135	$ 0	$ 0	$ 0	$ 0	$ 97,245
Lee 3 Rotamix	$ 0	$ 0	$ 0	$ 198	$ 6,424	$ 600	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 7,222
Lee 2 LNB	$ 0	$ 0	$ 133	$ 273	$ 1,886	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,292
Sutton 2 LNB	$ 0	$ 0	$ 0	$ 236	$ 1,900	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,136
Total without Waste Water	**$ 1,393**	**$ 26,527**	**$ 80,184**	**$ 168,118**	**$ 259,566**	**$ 309,456**	**$ 101,510**	**$ 28,087**	**-$ 88**	**$0**	**$ 0**	**$ 0**	**$ 974,754**
Asheville WWT	$ 0	$ 0	$ 0	$ 12,365	$ 1,289	-$ 306	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 13,348
Mayo WWT	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,042	$ 6,604	$ 9,000	13	$ 0	$ 0	$ 0	$ 19,659
Roxboro WWT	$ 0	$ 0	$ 0	$ 791	$ 11,965	$ 16,932	$ 5,127	$ 4,815	$5,339	$ 2,841	$ 0	$ 0	$ 47,810
Total Waste Water Treatment	**$ 0**	**$ 0**	**$ 0**	**$ 13,156**	**$ 13,253**	**$ 20,668**	**$ 11,732**	**$ 13,815**	**$5,352**	**$ 2,841**	**$ 0**	**$ 0**	**$ 80,817**
Total NC Smokestacks	$ 1,393	$ 26,527	$ 80,184	$ 181,273	$ 272,819	$ 330,124	$ 113,242	$ 41,902	$5,264	$ 2,841	$ 0	$ 0	$ 1,055,571
Total Estimated AFUDC							**$ 6,158**	**$ 4,312**	**$ 200**	**$ 100**	**$ 0**	**$ 0**	**$ 10,770**

Notes:

1. Historic year costs are actual, current year costs are projected, and future year costs are escalated
2. Costs reflect the Power Agency contribution