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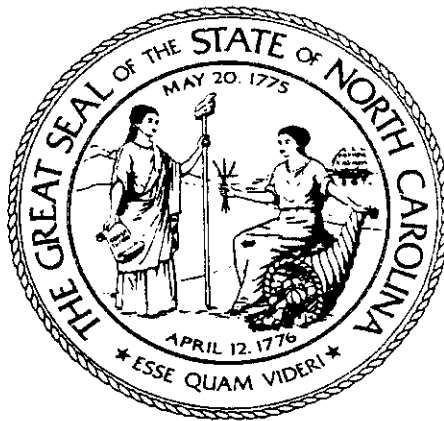
JUN 01 2007

Clerk's Office
N.C. Utilities Commission

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**



June 1, 2007

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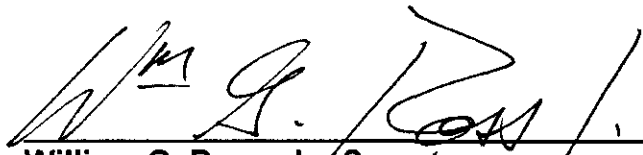
Implementation of the "Clean Smokestacks Act"

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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**

**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.**

Signed:



**William G. Ross, Jr., Secretary
Department of Environment and Natural Resources**

Signed:



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

June 1, 2007

Implementation of the "Clean Smokestacks Act"

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

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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 and the Joint Legislative Utility Review Committee.

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 30, 2007. 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 9, 2007, 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 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.

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 investor-owned electric utilities, 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 reviewed this information and determined that the submittals comply with the Act and, as proposed, appear adequate to achieve the emission limitations set out in G.S. 143-215.107D.

II. **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: "The initial plan for Progress Energy Carolinas, Inc. was submitted on July 29, 2002. Appendix A [of the attached Progress Energy submittal dated March 30, 2007, i.e., Attachment B] contains an updated version of this plan, effective April 1, 2007."

Duke Energy Response: "Exhibits A and B [of the attached Duke submittal dated March 30, 2007, i.e., Attachment A, outline the updated plan as of April 1, 2007, for] . . . current unit specific technology selections, projected operational dates, 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."

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 costs (capital costs) incurred by Progress Energy in calendar year 2006 were \$272.82 million. Progress Energy performed a significant amount of work at the Asheville and Roxboro plants. Progress Energy successfully placed the wet scrubber on Asheville Unit 2 into service in May 2006. Additionally, mechanical and electrical work for the Asheville Unit 1 selective catalytic reduction (SCR) project was completed in preparation for placing the SCR into service in the Spring of 2007. At the Roxboro plant, construction for the scrubber project continued on the four units in 2006. Specific unit construction activities included, but were not limited to: Unit 1 – completion of foundations for the absorber, recycle pump house, primary hydro cyclone tank, and electrical building; Unit 2 – completion of the recycle pump house, installation of induced draft fans and associated ducting, and installation of the hydro cyclone tank and transformers; Unit 3 – started installation of ducting from the existing stack to new induced draft fans, started construction of foundations for duct support steel, and continued installation of the absorber; Unit 4 – completed the absorber and started the erection of the recycle pump house and primary hydro cyclone tank. At the Lee plant, procurement and installation of the low-NOx burners for Unit 2 were completed in 2006. Also, construction activities associated with the Unit 3 Rotamix concluded. At the Mayo plant, engineering and design work continued in 2006 and contracts associated with the absorber tower and chimney were executed. At the Sutton plant, procurement and installation of the low-NOx burners for Unit 2 were completed in 2006.

Summary of Duke Energy Report: The actual environmental compliance costs incurred by Duke Energy in calendar year 2006 were \$427.98 million. Significant construction occurred in 2006 at the Belews Creek Steam Station. Construction of the major foundations and the concrete shell for the two new chimneys for the flue gas desulfurization (FGD) system was completed. Approximately 72% of the overall project was completed (54% of the construction activities) in 2006. At the Marshall Steam Station, tie-in of the Unit 4 absorber was completed, while initial tie-in of the Unit 3 ductwork and installation of the blanking plate were completed in 2006. All ductwork, with the exception of Unit 1 and Unit 2 tie-in, was set in 2006. At Allen Steam Station, contracts were awarded for the stack construction and wastewater treatment system associated with the FGD system. Other activities included, but were not limited to: relocation of a transmission line; site clearing, grubbing and earthwork; relocation of an ash line; relocation of coal handling railroad spurs; and placing purchase orders for all major electrical and mechanical equipment.

For the remaining Steam Stations (Cliffside, Buck, Dan River, and Riverbend), the Company reported that costs were incurred for a variety of things such as detailed engineering, material procurement and delivery, equipment installations, etc.

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 and Duke Energy Reports: In 2006, Progress Energy amortized \$140 million and Duke Energy amortized \$225.2 million. As indicated in the June 1, 2006 report to the Environmental Review Commission and the Joint Legislative Utility Review Committee ("the June 1, 2006 report"), Progress Energy, in response to a data request submitted by the Commission, had projected - assuming certain ratable amortization - that it would amortize \$87 million of environmental compliance costs in 2006. However, Progress Energy also noted that the Act grants Progress Energy the flexibility to vary the amortization schedule for 2006 and 2007 from \$0 to \$174 million per year. Also, as indicated in the June 1, 2006 report, Duke Energy, in response to a Commission data request, had projected that it would amortize \$250 million of environmental compliance costs in 2006.

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 between \$1.1 billion and \$1.4 billion, with the current point estimate being \$1.355 billion, a slight decrease from the 2006 cost estimate of \$1.362 billion. While costs of materials and labor continue to increase according to Progress Energy, it continues to refine the compliance strategy weighing a number of factors such as system load projections, expected fuel selection, available control equipment, anticipated performance and costs of emissions controls, and knowledge of and experience with emissions control options. For example, Progress Energy continues to evaluate the potential use of Furnace Sorbent Injection (FSI) technology at the Cape Fear Plant. The FSI technology may offer a more cost-effective compliance solution for Cape Fear than the original plan to use a wet scrubber. The North Carolina Division of Air Quality (DAQ) submitted an informational request to Progress Energy on April 25, 2007. The information requested of Progress Energy, among other things, concerned the evaluation of the FSI technology and whether there would be sufficient time to pursue alternatives to the FSI if the testing does not support its installation at Cape Fear. Progress Energy responded that, "if the testing at Robinson (SC) results in a conclusion that FSI will not be used at Cape Fear, PEC will have sufficient time to pursue alternatives prior to the CSA 2013 deadline." Finally, other more cost effective compliance solutions submitted by Progress Energy include the use of a dry scrubber at Sutton Unit 3 and use of Rotamix technology with combustion optimization at Lee Unit 3 for NOx control.

Progress Energy's current cost estimate of \$1.355 billion is \$542 million, or 67 percent, higher than the original 2002 cost estimate of \$813 million.

Summary of Duke Energy Report: Duke Energy reported that its currently expected costs are higher than the estimates provided in 2006. More specifically, in its 2007 report, the Company estimated its compliance costs to be \$1.965 billion, as compared to the \$1.732 billion reflected in its 2006 report, an increase of \$233 million, or 13 percent (detailed in Exhibit C of Attachment A of the Duke Energy report). As stated by Duke Energy, the reasons for this increase were:

- *Allen FGD Project* – The Allen FGD estimate has increased since the previous 2006 filing, with this increase attributable to continued ramp up in the power generation and/or environmental retrofit construction market and continued escalation of labor and commodity costs.
- *Cliffside Unit 5 FGD Project* – Like Allen, the Cliffside Unit 5 FGD estimate is primarily affected by labor, commodity and market escalation and thus shows an increase in total forecasted cost as compared to the estimate included in the 2006 filing. In addition, the current estimate now includes a larger portion of the costs associated with common FGD equipment and infrastructure assuming only one new Cliffside unit is built, versus assuming two new units are built as in the previous year's plan.
- *Selective Non-Catalytic Reduction (SCNR) & Burner Projects* – While there has been no significant change to the scope or timing of the NOx related projects remaining to be installed, all of the current forecasts have increased as compared to the 2006 filing. In each case, these increases approach 10% as compared to prior estimates and take into account the continued escalation of labor costs and ramp up in the environmental retrofit construction market as noted for the larger projects.
- *Marshall Unit 4 SNCR Project* – The Marshall Unit 4 SNCR equipment was installed in late 2006 at a cost significantly less than estimated in the previous year's plan. The decision to add the SCR technology to Marshall Unit 3 allowed for this reduction in costs as selected SNCR equipment in service on Unit 3 was redeployed to Unit 4.

Duke Energy's current cost estimate of \$1.965 billion is \$465 million, or 31 percent, higher than the original 2002 cost 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:

Asheville Plant

- Notified that air permit change for SO₃ mitigation system will be treated as an off permit change.
- Several erosion and sedimentation control plan updates were submitted.

Roxboro Plant

- Updates for air permit for coal handling and limestone handling were issued.
- Several erosion and sedimentation control plan updates were submitted.
- NPDES Permit - Authorization to Construct (ATC) relating to the gypsum settling pond and the bioreactor was received.

Mayo Plant

- Air permit was issued for construction of the FGD system.
- NPDES Permit modification for wastewater system received.
- Erosion and sedimentation control plan update was approved.

Lee Plant

- A prevention of significant deterioration (PSD) air permit was approved for installation of low NOx burners. Air permit approved for construction of the Rotamix System NOx control.
- NPDES permit amendment approved for Rotamix Urea Injection System on Unit 3.

Summary of Duke Energy Response:

Belews Creek

- NPDES Permit modification received.
- Landfill site suitability approved.
- Landfill construction plan – permit received.
- Air permit for FGD project received.
- Authorization to Construct (ATC) application for the wastewater treatment system was approved.
- Received permit to construct sanitary waste lagoon.
- Received permit to decommission existing sewage lagoon.
- Several soil erosion and sedimentation control plans have been approved.

Cliffside

- Air permit received for Unit 5 FGD.

Marshall

- Several soil erosion and sedimentation control plans have been approved.
- Landfill construction plan application received – Landfill (lining) permit received – Permit to operate Marshall FGD landfill received.
- Authorization to Construct (ATC) application for solids removal system was approved.
- ATC application for constructed wetlands was approved.
- Air permits received for SNCRs on Units 1-4.

Allen

- NPDES Permit modification received.
- DENR/ACOE Permit received.

- Air permit received for FGD and SNCRs on Units 2, 3, 4, and 5.
- Authorization to Construct (ATC) application for the wastewater treatment system was approved.
- Several soil erosion and sedimentation control permits have been received

Riverbend

- Air permits received for SNCRs on Units 4-7. Burner permits received for Units 5 and 6.

Dan River

- Air permits received for Burners on Units 1-3.

Buck

- Air permits received for Burners on Units 3 and 4 and for SNCRs on Units 5 and 6.

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: See Appendix C of the attached letter from Progress Energy dated March 30, 2007 (Attachment B of this report) for details of construction and installation of equipment. The Division of Air Quality (DAQ) submitted an informational request to Progress Energy on April 25, 2007. The information requested of Progress Energy, among other things, concerned the operational date of the SCR on Asheville Unit 1 and the Rotamix at Lee Unit 3. Progress Energy responded that "Installation of the Asheville Unit 1 SCR is being completed during the current outage. The unit is expected to be back on-line on or about May 7 (2007), and the SCR is expected to be in operation on or about May 10 (2007). The Lee #3 Rotamix system is online and is operating. Initial operation of the Rotamix system began in January 2007. Initial checkout and testing of the Rotamix system continued into February and March with final tuning and normal operation occurring in March 2007."

Summary of Duke Energy Response: See attached letter from Duke Energy dated March 30, 2007 (Attachment A), for details of construction anticipated for the next year.

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:

Asheville Plant

Air Permit

- "Current opacity rules pre-date saturated gas streams from wet scrubbers and

require representative measurements where condensed water vapor is not present. We will request revisions to the permit and underlying rules for opacity monitoring to include references to current federal regulations that exempt units with wet scrubbers from continuous opacity monitoring requirements.”

NPDES Permit

- “A request for Sampling Reduction at the internal Outfall 005 (treated FGD wet scrubber wastewater) was submitted January 25, 2007. A response is expected by end of first quarter.”

Roxboro Plant

Air Permit

- “A permit application for the emergency fire water diesel engine was submitted in January 2007. Authorization to construct the fire water diesel engine has been received; however, the operating permit must be received to support operation of the Unit 2 scrubber during the second quarter 2007.”
- “Current opacity rules pre-date saturated gas streams from wet scrubbers and require representative measurements where condensed water vapor is not present. We will request revisions to the permit and underlying rules for opacity monitoring to include references to current federal regulations that exempt units with wet scrubbers from continuous opacity monitoring requirements.”

Mayo Plant

NPDES Permit

- “An ATC request for the wastewater treatment system is expected to be submitted in the first quarter with response desired by the end of the second quarter.”
- “An ATC request for a new oil/water separator is expected to be submitted by the end of the first quarter with response expected by the end of the third quarter.”

Erosion and Sedimentation Control Plan

- “Rev F. for the increase in disturbed land (from 35 acres to 98 acres for the flue gas desulfurization system was submitted January 29, 2007. Additional plan revisions will be necessary as construction plans are developed.”

Lee Plant

- “A Title V permit application is due to be submitted in July 2007 in accordance with permit requirements associated with the low-NOx burner installation.”

Duke Energy Response:

Belews Creek Steam Station FGD

- Permit to operate the FGD Residue Landfill – Submit certification report August 13, 2007, expect permit to operate by October 23, 2007.

Cliffside Steam Station Unit 5 FGD

- Authorization to Construct (ATC) application anticipated September 2007.

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

Summary of Progress Energy Response: Progress Energy conducted performance testing of the SO₂ scrubbers at Asheville Units 1 and 2 in 2006. The testing confirmed the scrubbers had achieved their performance guarantee of 97 percent removal efficiency.

Progress Energy also tested the low-NOx burners (LNBs) at Sutton Unit 2 and Lee Unit 2 in 2006. The testing demonstrated that the LNBs met their respective performance guarantees.

Duke Energy Response: "No additional equipment related testing occurred in 2006." Duke Energy included SNCR and SCR tests done in prior years in the 2007 report for reference.

9. **G.S. 62-133.6(i)(9) requires:** *The number of tons of oxides of nitrogen (NOx) and sulfur dioxide (SO₂) 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.*

Progress Energy Response: "The total calendar year 2006 emissions from the affected coal-fired Progress Energy units are:

- NOx 46,501 [tons]
- SO₂ 175,226 [tons]"

Summary of Duke Energy Response: In the 2006 calendar year, the following were emitted from the North Carolina based Duke Energy coal-fired units:

- NOx 54,335.5 tons
- SO₂ 286,639.2 tons

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 2006, 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."

Duke Energy Response: "No emissions allowances have been acquired by Duke Energy Carolinas resulting from compliance with the emissions limitations set out in G.S. 143-215.107D."

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

Summary of DENR/DAQ Request: The DENR/DAQ submitted informational requests to Progress Energy and Duke Energy on April 25, 2007. The information requested, along with the information contained in the original March 30, 2007 submittals from Progress Energy and Duke Energy, support DENR/DAQ's conclusion that the plans and schedules of the companies appear adequate to achieve the emission limitations set out in G.S 143-215.107D.

The information requested on April 25, 2007, among other things, concerned: operational dates for control units at Progress Energy (answers outlined in Number 6 above); plan and timing if furnace sorbent injection (FSI) testing does not support the FSI installation at Cape Fear (answer outlined in Number 4 above); whether plans for maintaining NOx emissions at or below the cap(s) consider, for example, growth in energy sales; and an inquiry on how year-to-year meteorological variability affects energy demand and thus affects production from the coal-fired units and the related SO₂ and NOx emissions.

Progress Energy Response: In response to the DENR/DAQ question, "What are your plans for maintaining NOx emissions at or below the final (2007) cap considering, for example, growth in energy sales," Progress Energy noted, "PEC fully intends to comply with the annual NOx emissions cap. Planning for NOx emissions is included with planning for unit generation, fuel consumption, and fuel and operations costs. Year-to-date actual emissions with year-end projections are continuously monitored and are updated weekly to ensure annual compliance. High and low cases (energy, outages, performance, etc.) are continuously evaluated and monitored to provide PEC with a range of potential scenarios in order to prepare for additional actions to curb emissions, if needed."

In response to the DENR/DAQ question on how year-to-year meteorological variability affects energy demand and thus affects production from the coal-fired units and the related SO₂ and NOx emissions, Progress Energy noted, "PEC's base case forecast uses a weather-normalized load and energy forecast. Deviations from normal weather conditions increase or decrease system energy demand (depending on the specific deviation) and thus can result in an increase or decrease in actual emissions. For example, a hotter than normal summer would likely result in an increase in emissions while a milder summer would likely result in lower emissions."

Duke Energy Response: In response to the DENR/DAQ question, "What are your plans for maintaining NOx emissions at or below the final (2009) cap considering, for example, growth in energy sales," Duke Energy noted, "The projections above represent a system average capacity factor of 73%. To put this in perspective, the highest annual fossil system capacity factor Duke has ever achieved was 69% in 2005. The projection also includes a substantial amount of bulk power marketing (BPM) sales. If we had BPM sales at a historical high, this could increase NOx emissions in the

900 tons range to account for this load.” Duke stated that they expect to have a comfortable compliance margin even with off system sales.

In response to the DENR/DAQ question on how year-to-year meteorological variability affects energy demand and thus affects production from the coal-fired units and the related SO₂ and NO_x emissions, Duke Energy noted, “...we are planning to a very high system average capacity factor. Historically, we have had very hot summers and very cold winters but have never achieved the 73% annual CF we are currently planning to.

“In developing the appropriate compliance margin multiple scenarios were considered that increased NO_x emissions, including forced outages at the nuclear units and units with SCR, increase in BPM sales. Through this analysis it was determined that a 1,000 to 1,500 tons compliance margin was needed going into any year. Though we are installing the Marshall 3 SCR for the Charlotte 8 hour ozone attainment demonstration, it also provides compliance margin for the North Carolina Clean Smokestack Act (NC CSA).

“The total NO_x emissions and how each unit is performing is trended on a weekly basis. If the system total NO_x emissions were trending above the firm NC CSA cap, we would attempt to achieve lower NO_x emissions from our generation stations without consideration of performance. We would have the option to change the dispatch of units, limit BPM sales and at a last resort, purchase power and shut down the highest emitting generation units. Our plan is not to exceed the NC CSA firm cap unless under a force majeure situation.”

Summary of Commission Request: The Commission submitted discovery requests to Progress Energy and Duke Energy on April 12, 2007. The information requested, among other things, concerned current projected amortization schedules over the remaining years of the seven-year accelerated cost-recovery period.

Progress Energy Response: The Act requires Progress Energy to amortize \$569 million, which represents 70% of the original cost estimate of \$813 million, by the end of 2007. The Company indicated that \$535.2 million had been amortized as of December 31, 2006, leaving a total of \$33.8 million to be amortized during 2007.

With regard to the amounts to be amortized in 2008 and 2009, Progress Energy indicated in response to the Commission’s April 12, 2007 discovery request that it projected estimated amortization of \$122 million per year for each of those two years. However, in a Petition filed in Docket No. E-2, Sub 900, Progress Energy, among other things, has requested that the Commission satisfy the requirements of G.S. 62-133.6(d) by allowing it to amortize a total of \$244 million during calendar years 2008 and 2009, the result being that Progress Energy has requested the discretion to amortize up to \$174 million in either year, as currently permitted by G.S. 62-133.6(b), according to Progress Energy.

Progress Energy stated that it currently has no plans to write off or amortize any amounts above \$813 million in 2007 through 2009. Rather, Progress Energy has proposed that the environmental compliance costs incurred by Progress Energy in excess of \$813 million be included in its rate base. **[DENR/COMMISSION NOTE:** As previously indicated, Progress Energy currently estimates its total net environmental compliance costs to be approximately \$1.355 billion.]

Subsection (d) of G.S. 62-133.6, in pertinent part, provides as follows:

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. . . . The Commission shall issue an order pursuant to this subsection no later than December 31, 2007.

Commission proceedings are currently ongoing with respect to the requirements of G.S. 62-133.6(d) as highlighted above. Therefore, the Commission has not yet ruled regarding the annual amounts of environmental compliance costs to be amortized by Progress Energy in 2008 and 2009. However, the Commission will do so not later than December 31, 2007.

Duke Energy Response: The Act requires Duke Energy to amortize \$1.050 billion, which represents 70% of the original cost estimate of \$1.5 billion, by the end of 2007. The Company indicated that \$862 million had been amortized as of December 31, 2006, leaving a total of \$188 million to be amortized during 2007.

With regard to the amounts to be amortized in 2008 and 2009, Duke Energy indicated, in response to the Commission's April 12, 2007 discovery request, that such amounts were to be determined in Docket No. E-7, Sub 829. That docket was initiated by the Commission, by Order issued March 9, 2007, for the purpose of allowing the Commission to comply with the provisions of G.S. 62-133.6(d) as such statutory provisions pertain to Duke Energy.

Regarding Duke Energy's plan to write off or amortize any amounts above \$1.5 billion, Duke Energy stated that it will, no later than June 1, 2007, file testimony and exhibits with the Commission setting forth the information and data supporting its position regarding recovery of the remaining clean air compliance expenditures, that is, presumably, the environmental compliance costs incurred by Duke Energy in excess of \$1.5 billion. **[DENR/COMMISSION NOTE:** As previously indicated, Duke Energy currently estimates its total net environmental compliance costs to be approximately \$1.965 billion.]

Commission proceedings are currently ongoing with respect to the foregoing matters. Therefore, the Commission has not yet ruled regarding the annual amounts of environmental compliance costs to be amortized by Duke Energy in 2008 and 2009. However, the Commission will do so not later than December 31, 2007.

III. 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 (SO₂) 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 SO₂ and NOx from TVA's fleet of coal-fired power plants are inadequately controlled and therefore create a public nuisance. The Attorney General has asked the Court to require TVA to install NOx and SO₂ controls to abate the public nuisance. In July 2006 the District Court denied TVA's motions to dismiss the case, but TVA has appealed these rulings to the U.S. Court of Appeals in Richmond, Virginia. Oral argument has not yet been scheduled and it is uncertain when the appeal will be decided. Meanwhile, the parties are continuing to prepare for and are on schedule for a trial in Asheville in October 2007. TVA has recently announced plans to install NOx and SO₂ controls on its John Sevier plant, which is the closest TVA facility to North Carolina.

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) Clean Air Interstate Rule (CAIR). Among other things, the State is alleging 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. The Court will likely hear arguments in this matter in late 2007 or early 2008.

3) Also on July 8, 2005, the Attorney General filed a petition with the EPA requesting that the EPA administratively reconsider certain aspects of CAIR. EPA

denied this petition. The Attorney General has asked the D.C. Circuit to review this action as well, and this request will be heard along with the CAIR case.

4) On March 18, 2004, the State filed a petition under §126 of the Clean Air Act requesting that EPA impose NO_x and/or SO₂ controls on large coal-fired utility boilers in 13 upwind states that impact North Carolina's air quality. On March 15, 2006, the EPA denied the State's petition. The Attorney General has filed a petition in the D.C. Circuit seeking review of the denial of the petition. The matter will likely be heard by the Court in early 2008. The Attorney General also petitioned EPA for administrative reconsideration of the §126 petition.

5) Since the enactment of the Clean Smokestacks Act, the Attorney General and the Department of Environment and Natural Resources have on several occasions presented the Clean Smokestacks Act to other jurisdictions to demonstrate leadership and prompt similar actions in surrounding areas that impact North Carolina. On April 6, 2006, Governor Ehrlich of Maryland signed into law the Healthy Air Act (2006 Md. Laws 301) -- a Clean Smokestacks-type law that significantly limits emissions of SO₂ and NO_x from large coal-fired utility boilers in Maryland. Maryland also is in the process of promulgating rules that will further tighten controls on large NO_x and SO₂ sources.

6) The Attorney General is also seeking a prompt resolution about whether large stationary sources of NO_x in Georgia must comply with the summertime NO_x cap under EPA's "NO_x SIP Call" rule, which is designed to help downwind States reduce ambient levels of ozone. This aspect of the NO_x SIP Call has been under review by EPA and EPA has failed to resolve the issue in a timely manner.

IV. 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 (NO_x) and Sulfur Dioxide (SO₂) 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 (NO_x) and sulfur dioxide (SO₂) 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 2006-79 changed the beginning date of the requirements of this Section to September 1, 2007.

Environmental Management Commission and DENR Response: A letter was submitted to the Environmental Review Commission from Dr. David Moreau, Environmental Management Commission Chairman, dated April 3, 2006, which stated the following:

Since the Clean Smokestacks Act was passed in June 2002, significant Federal regulatory changes have occurred. Specifically, the Clean Air Interstate Rule (CAIR) requires North Carolina's neighboring states to achieve major reductions in NO_x and SO₂ -- reductions that require installation of state-of-the-art control equipment. Although there may be questions about the timing and emissions reductions of CAIR, the Division of Air Quality (DAQ) believes CAIR will ultimately require Duke Energy and Progress Energy to enhance existing or add new controls that are consistent with the latest technology.

The Clean Smokestacks Act already requires that state of the art control equipment be installed on many units in North Carolina. CAIR annual NO_x and SO₂ emissions budgets are even lower than those set by the Clean Smokestacks Act and this could result in even more units in North Carolina having state of the art control equipment applied.

Given the recent action by the Federal government regarding power plant emissions, it is recommended that the study as to whether or not further State action is required be extended while evaluation is made of the progress of North Carolina in complying with both the clean Smokestacks Act and CAIR.

The DENR/DAQ generally believes the current compliance plans represent a suite of state-of-the-art controls, taking into consideration both emissions reductions and costs of control. The Environmental Management Commission and DENR/DAQ will continue to evaluate control options through the requirements of this section as both the Clean Smokestacks Act compliance dates and the CAIR compliance dates draw near.

V. Section 12 of the Act provides: *The General Assembly anticipates that measures implemented to achieve the reductions in emissions of oxides of nitrogen (NO_x) and sulfur dioxide (SO₂) 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 (SO₂) 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: The 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 will result from the control of NOx and SO₂ 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". The Division has also submitted the third and final report titled Mercury Emissions and Mercury Controls for Coal-Fired Electrical Utility Boilers. In 2006, DAQ developed a state mercury rule that goes beyond the federal Clean Air Mercury Rule (CAMR) that took effect in November 2006. 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 two sets of independent requirements that they have to meet. First, they have to satisfy the requirement set out in the EPA guideline rule, which has been incorporated into the State's mercury regulation. This requirement is that each unit's account contains enough allowances at the end of the year to equal or exceed its actual emissions for that year. Second, these units have to meet a 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. Both requirements are independent of each other. Meeting the first requirement does not relieve the company from the need to meet the second requirement. However, meeting the second requirement, the State-only requirement, will greatly aid the companies in meeting the first requirement.

VI. 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 (CO₂) 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 (CO₂). 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 (CO₂) 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 (CO₂) is reduced as a result of the reductions in the emissions of oxides of nitrogen (NO_x) and sulfur dioxide (SO₂) 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: The 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 CO₂ control from coal-fired utility boilers. The second report primarily focused on "definition of options". The DAQ submitted the third and final report titled, "Carbon Dioxide (CO₂) 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 is to evaluate, discuss, and formalize consensus-based recommendations for CO₂ and other greenhouse gas reductions through a formal stakeholder process. Determination of economic benefits to North Carolina will be assessed for each prospective recommendation. The CAPAG will work in conjunction with the LCGCC in providing periodic updates. The inaugural meeting of the CAPAG was held on February 16, 2006. The CAPAG is now in the final stages of utilizing technical workgroups. These technical workgroups contain experts 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 greenhouse gas registry). The CAPAG is working diligently towards a comprehensive North Carolina Climate Action Plan, with a current target to complete it by the end of 2007.

VII. Supplementary Information: As noted in earlier reports, the Public Staff - North Carolina Utilities Commission (Public Staff) will audit the books and records of Progress Energy and Duke Energy on an ongoing basis in regard to the costs incurred and amortized in compliance with the provisions of the Act. The Public Staff has undertaken such a review, focusing on the verification of costs related to complying with the Act, the amortization of those costs, and the operating results of emission reduction equipment installed by Progress Energy and Duke Energy.

The Public Staff filed its most recent reports in the present regard with the Commission on May 25, 2007. (The report regarding PEC was subsequently revised on May 29, 2007.) Such reports, which are a continuation of the Public Staff's ongoing review, present an overview of certain work performed by the Public Staff and its findings for the 12-month period ending December 31, 2006. Attached, and made part of this report, are the Public Staff's reports for Duke Energy and Progress Energy, Attachments C and D, respectively.

VIII. Conclusions

The DENR/DAQ carefully reviewed and considered the information provided by Progress Energy and Duke Energy in their March 30, 2007 compliance plan submittals and their May 2007 supplemental submittals in response to informational requests from DENR/DAQ on April 25, 2007. The information in the submittals, including the construction undertaken and completed through the past year and consideration of the fraction of construction remaining and permits received and applied for in the past year, point toward steady progress in meeting the prescribed goals of the Clean Smokestacks Act. DENR/DAQ staff also analyzed the emissions projections and assumptions on growth in energy sales. A specific analysis of the NO_x emissions relative to the 2007 cap was completed using data from the submittals along with publicly available 2006 emissions data from USEPA's Clean Air Markets Division Web Site. Similar analysis of SO₂ emissions will be possible in future reports as the first SO₂ cap in 2009 approaches. Additionally, DENR/DAQ notes that, as emission controls have come online for both Progress Energy and Duke Energy, their ability to refine the expected future year emission rates for controls yet to be installed is enhanced based on operational performance of similar technologies already put into service.

The Commission has also carefully reviewed and considered the information and data provided by the investor-owned public utilities in their 2007 Clean Smokestacks annual reports and in response to the Commission's discovery requests of April 12, 2007. Based upon such information, it appears that both Progress Energy and Duke Energy are on track to meet the statutorily imposed 70% accelerated amortization requirement during the five-year rate freeze period in the amounts of \$569.1 million and \$1.050 billion, respectively. Further, as required by the Act, the Commission has scheduled hearings for the purpose of (1) determining the annual cost recovery amounts that each investor-owned public utility shall be required to record and recover during calendar years 2008 and 2009; (2) reviewing the investor-owned public utilities' current estimates of total projected environmental compliance costs and revising such costs, if necessary, to ensure that they are just, reasonable, and prudent based on the most recent cost information available; and (3) consulting with the Secretary of DENR to receive advice as to whether the investor-owner public utilities' 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 will rule on the aforesaid matters not later than December 31, 2007.

In summary, it appears 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, Clean Smokestacks Compliance Plan Annual Update for 2007, Submitted by Cover Letter Dated March 30, 2007
- Attachment B:** Progress Energy Carolinas, Inc. Annual North Carolina Clean Smokestacks Act Compliance Report, Submitted by Cover Letter Dated March 30, 2007
- Attachment C:** Report of the Public Staff on Costs Incurred and Amortized by Duke Energy Carolinas, LLC in Compliance with Session Law 2002-4, Filed on May 25, 2007
- Attachment D:** Report of the Public Staff on Costs Incurred and Amortized by Progress Energy Carolinas, Inc. in Compliance With Session Law 2002-4, Filed on May 25, 2007 (Revised on May 29, 2007)



DUKE ENERGY CAROLINAS, LLC

225 Hillsborough Street, Suite 160
Raleigh, NC 27603

919 235 0995

919 828 5240 fax

March 30, 2007

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

FILED
MAR 30 2007
Clerk's Office
N.C. Utilities Commission

Subject: Docket No. E-7, Sub 718
Duke Energy Carolinas, LLC NO_x and SO₂ Compliance Plan Annual Update
Record No. NC CAP 006

Dear Ms. Vance:

Duke Energy Carolinas, LLC is required by Senate Bill 1078 (the "North Carolina Clean Air Legislation") to file information on or before April 1 of each year to update the North Carolina Utilities Commission on ("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 2007 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 SO₂ includes:

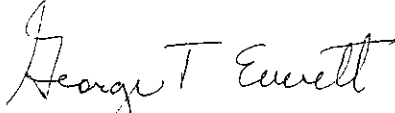
NO_x Control – The installation of Selective Catalytic Reduction (SCR) on Cliffside Steam Station Unit 5 and Belews Creek Steam Station Units 1&2 has been completed. Our NO_x plans continue to include the installation of Selective Non-Catalytic Reduction (SNCR) on 15 units and burner work at our remaining smaller units with the exception of Cliffside Units 1-4. With these installations, the company can demonstrate compliance with the 2007 and 2009 NO_x caps under Senate Bill 1078.

SO₂ Control – The installation of wet scrubbers on our twelve largest generating units continues to be our plan for compliance with the 2009 and 2013 SO₂ caps under the North Carolina Clean Air Legislation. The company continues to work under an accelerated schedule with respect to the Allen scrubber project to maintain design and construction continuity throughout the scrubber program and also assure compliance with the federal Clean Air Interstate Rule. Estimated costs for the scrubber projects at Cliffside Unit 5 and Plant Allen continue to rise due to escalation of labor and commodity prices as well as the continued run up of costs in the power generation and environmental retrofit construction market.

Exhibits A and B outline current unit specific technology selections, projected operational dates, 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 Environmental Compliance Costs for these pollution control projects are included in Exhibit C.

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, Ph.D.
Director, Environmental/Legislative Affairs
Duke Energy Carolinas

Enclosures

cc: Robert P. Gruber
Executive Director – Public Staff
4326 Mail Service Center
Raleigh, NC 27699-4326

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 (Annual Update) is filed on behalf of Duke Energy Carolinas, LLC; that 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 knowing omitted or misstated therein.

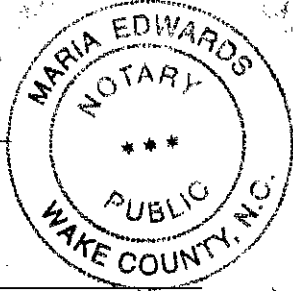
George T. Everett

George T. Everett, Ph.D.
Director, Environmental and Legislative Affairs

March 30, 2007
Date

Subscribed and sworn before me this the 30th day of March, 2007.

Maria Edwards
Notary Public



My commission expires 3/2/2008

Duke Energy Carolinas, LLC
General Assembly of North Carolina Session 2001
Senate Bill 1078 – Improve Air Quality/Electric Utilities (NC Clean Air Legislation)
2007 Annual Data Submittal

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 plan as of this date for technology selections by facility and unit, projected operational dates, 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 described below:

NO_x Compliance

- Emission Rate Changes – Expected rates have been adjusted in this 2007 update based on 2006 operational performance:
 - Emission rates for the Allen units were adjusted based on 2006 ozone season performance of the Units 1, 3 & 4 SNCR equipment. Expected rates were increased by 0.01 for Units 1 & 2 and 0.02 for Units 3, 4 & 5.
 - The Belews Creek Unit 1 expected rate was increased by 0.01 based on 2006 operational results.
 - The Buck Units 3 & 4 expected rates in 2009 were increased by 0.01 based on operation of the similar Dan River Unit 2 with new Separated Over-fired Air (SOFA) burner equipment in early 2007. The Buck Unit 3 expected rate in 2007 was decreased by 0.02 based on the timing of the SOFA installation.
 - The Buck Units 5 & 6 expected rates were increased by 0.02 based on the early 2007 performance of the recently installed SNCR equipment.
 - Cliffside Units 1 - 4 expected rates were changed based on 2006 performance.
 - The Dan River Units 1 & 2 expected rates were increased slightly based on operations of the SOFA equipment on Unit 2 in early 2007.
 - The Marshall Units 1 - 4 expected rates were increased by 0.01 based on operation in 2006 and the effect on baseline NO_x of the coals used with the scrubber.
 - The 2009 expected rate for Marshall Unit 3 was decreased significantly based on the expected addition of SCR equipment. This SCR addition is expected to be operational in 2009 primarily in support of the 8-hour ozone attainment demonstration for the Charlotte region. Increased mercury removal in support of the federal Clean Air Mercury Rule (CAMR) and improved ability to support existing NO_x emission limitations are added benefits associated with this project. Similar to other SCR additions attributed primarily to compliance with regulations other than the North Carolina Clean Air Legislation, costs associated with this Marshall Unit 3 SCR project are not "environmental compliance costs" within the meaning of that term as used in the North Carolina Clean Air Legislation.
 - The Riverbend Units 4 – 7 expected rates were changed based on 2006 and early 2007 operational results.

SO₂ Compliance

- New Pulverized Coal (PC) Unit – This 2007 update assumes the addition of one new 800 MW coal unit at the Cliffside Steam Station. The 2013 expected compliance plan includes this unit along with the corresponding retirement of Cliffside Units 1-4.
- Schedule Changes – Optimization of the 2009 scrubber tie-in outages for the Allen Units 1 – 5 has resulted in some minor changes to the expected emission rates for the 2009 year.
- Emission Rate Changes – Expected rate changes have been adjusted in this 2007 update for the Buck and Cliffside stations:
 - The Buck Units 3 – 6 expected rates were increased. These new rates assume that the use of lower sulfur Colombian coal is discontinued given that it is not cost competitive in the current market. Forecasted prices for this coal do not currently provide a cost effective solution as compared to domestic options.
 - The Cliffside Units 1 – 5 rates were adjusted based on the expected sulfur content in the coal.

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 2006 calendar year, Duke Energy Carolinas spent **\$427,984,400** 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, and a description of the associated activities is provided below:

Allen Steam Station FGD

- Provided Limited Notice to Proceed (LNTP) to EPC Contractor 4/3/06
- Provided Full Notice to Proceed (FNTP) to EPC Contractor 8/31/06
- Awarded Wastewater Treatment engineering contract 3/1/06
- Awarded Wastewater Treatment construction contract 12/22/06
- Awarded Stack construction contract 5/16/06
- Completed relocation of 230kV Transmission Line 8/1/06
- Started site clearing, grubbing and earthwork
- Completed relocation of ash line 12/22/06
- Completed relocation of coal handling railroad spurs 11/29/06
- Placed purchase orders for all major electrical and mechanical equipment

Belews Creek Steam Station FGD

- Completed construction of the major foundations for the FGD System
- Completed construction of the concrete shell for the two new chimneys
- Completed 95% of construction for the Constructed Wetlands (part of the waste water treatment system)
- Achieved a completion status of 72% on the overall project (54% of construction activities)

Cliffside Steam Station Unit 5 FGD

- Continued preliminary construction planning and development of conceptual site layout

Marshall Steam Station FGD

- Completed tie-in of the Unit 4 Absorber; began initial operations of Unit 4 and common equipment on 10/30/06; achieved substantial completion on 12/20/06
- Completed initial tie-in of the Unit 3 ductwork and installation of blanking plate
- Completed setting all ductwork with the exception of Unit 1 and Unit 2 tie-in sections
- Completed lining of FGD gypsum landfill
- Completed engineered wetlands installation
- Completed Unit 4 CEMS RATA testing and certification
- Completed NSPS testing of material handling systems per air permit

Allen Steam Station SNCR, Unit 2

- Completed detailed engineering
- Completed procurement, installation and commissioning associated with the site's reagent storage equipment

Allen Steam Station SNCR, Unit 3

- Completed remaining small close-out activities

Allen Steam Station SNCR, Unit 4

- Completed material delivery and installation of the Unit 4 SNCR equipment including supporting plant air and dilution water equipment

Allen Steam Station SNCR, Unit 5

- No significant activity completed in 2006

Buck Steam Station Burners, Unit 3

- Completed detailed engineering and material procurement in preparation for 2007 installation

Buck Steam Station Burners, Unit 4

- Completed detailed engineering and material procurement in preparation for 2007 installation

Buck Steam Station SNCR, Unit 5

- Completed detailed engineering
- Completed material delivery and installation of the Unit 5 SNCR equipment including plant air, dilution water and reagent storage equipment required for SNCR operation

Buck Steam Station SNCR, Unit 6

- Completed detailed engineering, material delivery and installation of the Unit 6 SNCR equipment

Dan River Steam Station Burners, Unit 2

- Completed installation of burners in fall of 2006

Dan River Steam Station Burners, Unit 3

- Completed installation of burners in fall of 2006

Marshall Steam Station SNCR, Unit 1

- Completed installation of the Unit 1 SNCR equipment

Marshall Steam Station SNCR, Unit 2

- Completed material procurement and delivery in preparation for 2007 installation
- Completed procurement, installation and commissioning associated with the site's reagent storage equipment

Marshall Steam Station SNCR, Unit 3

- Completed remaining small close-out activities

Marshall Steam Station SNCR, Unit 4

- Completed detailed engineering, material procurement and delivery, and installation of the Unit 4 SNCR equipment

Riverbend Steam Station SNCR, Unit 4

- Completed detailed engineering, material procurement and delivery in preparation for 2007 installation

Riverbend Steam Station SNCR, Unit 5

- Completed detailed engineering, material procurement and delivery in preparation for 2007 installation

Riverbend Steam Station SNCR, Unit 6

- Completed detailed engineering, material procurement and delivery, and installation of the Unit 6 SNCR equipment
- Completed procurement, installation and commissioning associated with the site's reagent storage equipment

Riverbend Steam Station SNCR, Unit 7

- Completed detailed engineering, material procurement and delivery, and installation of the Unit 7 SNCR equipment
- Completed installation of plant air and dilution water equipment required for SNCR operation

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

In the 2006 calendar year, **\$225,236,000** was amortized related to construction work activity in support of compliance with the provisions of G.S. 143-215.107D. **\$862,665,143** has now been amortized in total for the program through year-end 2006.

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. Changes to the expected costs as compared to past compliance plans are described below:

- Allen FGD Project – The Allen FGD estimate has increased since the previous 2006 filing and is attributable to continued ramp up in the power generation and/or environmental retrofit construction market, and continued escalation of labor and commodity costs.
- Cliffside Unit 5 FGD Project – Like Allen, the Cliffside 5 FGD estimate is primarily affected by labor, commodity and market escalation and thus shows an increase in total forecasted cost as compared to the estimate included in the 2006 filing. In addition, the current estimate now includes a larger portion of the costs associated with common FGD equipment and infrastructure assuming only one new Cliffside unit is built, versus assuming two new units are built as in the previous year's plan.
- SNCR & Burner Projects – While there has been no significant change to the scope or timing of the NO_x related projects remaining to be installed, all of the current forecasts have increased as compared to the 2006 filing. In each case, these increases approach 10% as compared to prior estimates and take into account the continued escalation of labor costs and ramp up in the environmental retrofit construction market as noted for the larger projects.
- Marshall Unit 4 SNCR Project – The Marshall Unit 4 SNCR equipment was installed in late 2006 at a cost significantly less than estimated in the previous year's plan. The decision to add the SCR technology to Marshall Unit 3 allowed for this reduction in costs as selected SNCR equipment in service on Unit 3 was redeployed to Unit 4.

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.

Allen Steam Station FGD

- Request to revise NPDES Permit to include FGD wastewater – Submitted 1/24/06; received revision 9/11/06
- Submittal to DENR/ACOE regarding stream crossing of entrance road – Received permits 5/25/06
- Air Permit Application – Submitted 4/10/06; received Permit 6/30/06

- Authorization to Construct (ATC) application for Wastewater Treatment System – Submitted 9/14/06; received Permit to Construct 12/15/06
- NOTE: all erosion control permits are in EPC contractor's scope for the Allen FGD Project and were received in 2006 (7/13/06 and 12/18/06). EPC contractor has also applied for air permit associated with flue liner fabrication on 11/1/06 and expects to receive permit in early 2007.

Belews Creek Steam Station FGD

- Request to revise NPDES Permit to include FGD wastewater – Submitted 6/30/04; received Permit Revision 5/16/05
- Initial Erosion Control Permit – Submitted 2/4/05; received Permit 3/7/05
- Landfill Site Suitability Application – Submitted 3/30/05; received Site Suitability Approval Letter 6/19/06
- Air Permit Application for Belews Creek FGD project – Submitted 4/18/05; received Air Permit 2/6/06
- Authorization to Construct (ATC) application for Wastewater Treatment System – Submitted 7/21/05; received Permit to Construct 12/27/05
- Authorization to Construct (ATC) application for Constructed Wetlands – Submitted 7/21/05; received Permit to Construct 12/27/05
- Revised Landfill Construction Plan Application – Submitted 9/30/05; received Permit to Construct 6/29/06
- Air Permit – Notice of Intent to Construct – Submitted 10/11/05; received Permit to Construct 10/24/05
- Authorization to Construct Sanitary Waste Lagoon – Submitted 3/23/06; received Permit to Construct 9/1/06
- Existing Sewage Lagoon Approval to Decommission – Submitted 10/31/06; received permit 1/25/07
- NOTE: Revisions to Erosion Control Permit submitted on various dates; most recent revised permit received 3/30/06

Cliffside Steam Station Unit 5 FGD

- Air Permit Application – Submitted 12/16/05; received 12/15/06

Marshall Steam Station FGD

- Landfill Construction Plan Application – Submitted 4/1/04; received 2/4/05
- Sedimentation and Erosion Control Plan Permits
 - Limestone/Gypsum Conveyor – Submitted 6/17/04; received 7/9/04
 - Limestone/Gypsum Conveyor Expansion – Submitted 12/15/04; received 12/30/04
 - Constructed Wetland Treatment System – Submitted 7/26/04; received 8/18/04
 - Gypsum Landfill – Submitted 3/31/04; received 4/21/04
- 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

- Air Permit Revisions (for material handling issues) – Submitted 9/2/05; received 12/7/05
- Landfill Permit Documents (to line landfill) – Submitted 12/15/05; received 6/5/06
- Permit to Operate Marshall FGD Landfill – Submitted 10/27/06; received 11/21/06

Allen Steam Station SNCR, Unit 2

- 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

Allen Steam Station SNCR, Unit 5

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

Buck Steam Station Burners, Unit 3

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

Buck Steam Station Burners, Unit 4

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

Buck Steam Station SNCR, Unit 5

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

Buck Steam Station SNCR, Unit 6

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

Dan River Steam Station Burners, Unit 1

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

Dan River Steam Station Burners, Unit 2

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

Dan River Steam Station Burners, Unit 3

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

Marshall Steam Station SNCR, Unit 1

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

Marshall Steam Station SNCR, 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 SNCR, Unit 4

- 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 SNCR, Unit 5

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

Riverbend Steam Station Burners, Unit 6

- Air Permit Application – Submitted 5/14/03; Received September 2003

Riverbend Steam Station SNCR, Unit 6

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

Riverbend Steam Station SNCR, 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 relocation of fuel oil tank and transfer system
- Complete construction of stack shell
- Complete construction of new access driveway
- Complete all major building foundations and steel erection
- Complete initial duct tie-in outages for Units 1-5
- Complete all major equipment foundations
- Mobilize FRP liner fabrication facility
- Complete major process equipment procurement
- Receive auxiliary transformer on site

Belews Creek Steam Station FGD

- Complete construction and commissioning of all FGD Systems
- Place new Sanitary Waste System into operation
- Achieve Unit 1 FGD Substantial Completion - Expect in February 2008

Cliffside Steam Station Unit 5 FGD

- Complete clearing and grubbing required to begin FGD construction
- Begin earthwork excavation, blasting and hauling activities

- Begin structural/foundation work for FGD equipment
- Complete Unit 5 chimney foundation

Marshall Steam Station FGD

- Complete construction, turnover and commissioning of Unit 3 FGD systems
- Complete final tie-in of Unit 3 ductwork; remove blanking plate; and begin operations, testing and tuning of Unit 3 FGD systems
- Achieve substantial completion for Unit 3
- Complete construction, turnover and commissioning of Unit 1/2 FGD systems
- Complete final tie-in of Unit 2 ductwork and begin operations, testing and tuning of Unit 1/2 FGD systems
- Complete final tie-in of Unit 1 ductwork
- Achieve Substantial Completion for Unit 1/2
- Achieve Marshall FGD Project Completion

Allen Steam Station SNCR, Unit 2

- Complete material procurement, installation and commissioning of SNCR equipment in time to support operation in summer 2007

Allen Steam Station SNCR, Unit 5

- Complete detailed engineering and material procurement activities
- Begin equipment installation activities in support of a 2008 project completion date

Buck Steam Station Burners, Unit 3

- Complete installation of burners in early 2007

Buck Steam Station Classifiers, Unit 3

- Complete installation of classifiers in early 2007

Buck Steam Station Burners, Unit 4

- Complete installation of burners in early 2007

Buck Steam Station Classifiers, Unit 4

- Complete installation of classifiers in early 2007

Dan River Steam Station Burners, Unit 1

- Complete detailed engineering and material procurement activities
- Complete installation of burners in late 2007

Dan River Steam Station Classifiers, Unit 1

- Complete installation of classifiers in late 2007

Marshall Steam Station SNCR, Unit 2

- Complete installation and commissioning of SNCR equipment in preparation for operation in summer 2007

Riverbend Steam Station SNCR, Unit 4

- Complete installation and commissioning of SNCR equipment in preparation for operation in summer 2007

Riverbend Steam Station SNCR, Unit 5

- Complete installation and commissioning of SNCR equipment in late 2007

Riverbend Steam Station SNCR, Unit 6

- Complete commissioning and small project close-out activities

Riverbend Steam Station SNCR, Unit 7

- Complete commissioning and small project close-out activities

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.

Belews Creek Steam Station FGD

- Permit to operate the FGD Residue Landfill - Submit Certification Report 8/13/07, Expect permit to operate by 10/23/07

Cliffside Steam Station Unit 5 FGD

- Authorization to Construct (ATC) application anticipated September 2007

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

No additional equipment related testing occurred in 2006. The SNCR and SCR tests that occurred in prior years that were used in evaluating technology selections are repeated in this 2007 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 NO_x with ammonia slip of less than 5 ppm at full load.
- During the 2004 ozone season, Allen Unit 1 achieved a 0.162# NO_x/MMBTU outlet rate, 5% better than the 0.17#/MMBTU target established for the unit.

Belews Creek Steam Station SCR

- SCR Equipment installation was completed in 2003 in support of the EPA/SIP Call requirements for NO_x reduction. While Belews Creek had operational problems in the first half of the 2004 ozone season, many of these issues were addressed on Belews Creek Unit 1 by August, 2004. Subsequently, tests performed during the months of August and September showed that when the SCR Equipment was in service during this time, emissions averaged 0.07# NO_x/MMBTU

- 9. The number of tons of oxides of nitrogen (NO_x) and sulfur dioxide (SO₂) 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 2006 calendar year, **54,335.5** tons of NO_x and **286,639.2** tons of SO₂ were emitted from the North Carolina based 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.**

No emissions allowances have been acquired by Duke Energy Carolinas resulting from compliance with the emissions limitations set out in G.S. 143-215.107D.

- 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.

Expected Duke Energy Carolinas Compliance for NC Clean Air Plan as of 4/1/2007
(Exhibit A)

NO _x							
Facility	Unit	Technology	Operational Date	2007 Compliance		2009 Compliance	
				Expected Rate #/MMBTUs	Tons	Expected Rate #/MMBTUs	Tons
Allen	1	SNCR	2003	0.170	885	0.170	898
Allen	2	SNCR	2007	0.180	773	0.170	826
Allen	3	SNCR	2005	0.180	1,450	0.180	1,484
Allen	4	SNCR	2006	0.180	1,592	0.180	1,632
Allen	5	SNCR	2008	0.230	2,004	0.180	1,542
Belews Creek	1	SCR	2003	0.070	2,045	0.070	2,628
Belews Creek	2	SCR&Burners	2004	0.060	2,234	0.060	1,754
Buck	3	Burners	2007	0.260	338	0.230	346
Buck	4	Burners	2007	0.280	216	0.230	190
Buck	5	SNCR	2006	0.170	670	0.170	711
Buck	6	SNCR	2006	0.170	671	0.170	704
Cliffside	1	Tuning Only	2004	0.400	262	0.400	242
Cliffside	2	Tuning Only	2004	0.400	259	0.400	239
Cliffside	3	Tuning Only	2004	0.390	505	0.380	529
Cliffside	4	Tuning Only	2004	0.390	534	0.380	527
Cliffside	5	SCR	2002	0.062	1,184	0.062	1,239
Dan River	1	Burners	2008	0.370	483	0.225	353
Dan River	2	Burners	2006	0.240	394	0.240	407
Dan River	3	Burners	2006	0.216	796	0.216	812
Marshall	1	SNCR	2006	0.180	2,360	0.179	2,279
Marshall	2	SNCR	2007	0.200	2,151	0.179	2,283
Marshall	3	SNCR/SCR ¹	2005/2009	0.200	4,527	0.061	1,421
Marshall	4	SNCR	2007	0.200	4,408	0.200	4,321
Riverbend	4	SNCR	2007	0.189	432	0.178	428
Riverbend	5	SNCR&Burners	2008	0.230	501	0.179	439
Riverbend	6	SNCR&Burners	2006	0.180	664	0.165	636
Riverbend	7	SNCR	2006	0.165	622	0.165	664
Expected Total:					32,961		29,534
Compliance Limit:					35,000		31,000

¹ SNCR Technology in service on Marshall Unit 3 expected to be replaced by SCR Technology in 2009 in support of 8-hour ozone attainment demonstration in the Charlotte region. Similar to other SCR additions to comply with other laws besides the North Carolina Clean Air Legislation, costs associated with this Marshall Unit 3 SCR project are not "environmental compliance costs" within the meaning of that term as used in the North Carolina Clean Air Legislation.

Technology
 Burners – Overfired Air or Separated Overfired Air with associated Mill Classifier installations
 SCR – Selective Catalytic Reduction
 SNCR – Selective Non-Catalytic Reduction

Expected Duke Energy Carolinas Compliance for NC Clean Air Plan as of 4/1/2007
(Exhibit B)

SO ₂							
Facility	Unit	Technology	Operational Date	2009 Compliance		2013 Compliance	
				Expected Rate #/MMBTUs	Tons	Expected Rate #/MMBTUs	Tons
Allen	1	Scrubber	2009	0.300	1,585	0.150	719
Allen	2	Scrubber	2009	0.250	1,215	0.150	653
Allen	3	Scrubber	2009	1.400	11,543	0.150	1,167
Allen	4	Scrubber	2009	1.300	11,789	0.150	1,312
Allen	5	Scrubber	2009	0.700	5,996	0.150	1,181
Belwe's Creek	1	Scrubber	2008	0.150	5,632	0.150	5,596
Belwe's Creek	2	Scrubber	2008	0.150	4,385	0.150	5,368
Buck	3			1.400	2,107	1.400	1,631
Buck	4			1.400	1,157	1.400	934
Buck	5			1.400	5,852	1.400	5,453
Buck	6			1.400	5,794	1.400	5,161
Cliffside	1			1.600	969	0.000	0
Cliffside	2			1.600	954	0.000	0
Cliffside	3			1.600	2,228	0.000	0
Cliffside	4			1.600	2,221	0.000	0
Cliffside	5	Scrubber	2010	1.600	32,151	0.150	2,817
Cliffside	6	Scrubber	2011	0.000	0	0.080	2,133
Dan River	1			1.400	2,196	1.400	1,895
Dan River	2			1.400	2,374	1.400	2,009
Dan River	3			1.400	5,262	1.400	4,813
Marshall	1	Scrubber	2007	0.150	1,909	0.150	1,938
Marshall	2	Scrubber	2007	0.150	1,916	0.150	1,667
Marshall	3	Scrubber	2007	0.150	3,495	0.150	3,427
Marshall	4	Scrubber	2006	0.150	3,241	0.150	3,534
Riverbend	4			1.550	3,717	1.550	2,596
Riverbend	5			1.550	3,799	1.550	3,033
Riverbend	6			1.550	5,965	1.550	5,267
Riverbend	7			1.550	6,229	1.550	5,446
Expected Total:					135,681		69,750
Compliance Limit:					150,000		80,000

Expected Duke Energy Carolinas Compliance Costs for NC Clean Air Plan as of 4/1/2007
(Exhibit C)

Facility	Unit(s)	Technology	Operational Date	Spent to Date							Remaining 2007-2010 (\$000)	Project Total (\$000)
				2001 (\$000)	2002 (\$000)	2003 (\$000)	2004 (\$000)	2005 (\$000)	2006 (\$000)	2007-2010 (\$000)		
Allen	1-5	Scrubber	2009	\$0.9	(\$0.9)	\$1,099.8	(\$11.8)	\$5,348.3	\$62,752.8	\$433,777.7	\$502,966.8	
Belwus Creek	1-2	Scrubber	2008	\$0.0	\$0.0	\$1,121.3	\$5,999.1	\$106,433.5	\$250,648.5	\$179,399.0	\$543,601.4	
Cliffside	5	Scrubber	2010	\$0.0	\$0.0	\$978.5	\$287.5	\$112.0	\$3,175.2	\$394,446.9	\$399,000.0	
Marshall	1-4	Scrubber	2007	\$0.0	\$0.0	\$10,213.7	\$92,096.3	\$218,129.8	\$74,162.8	\$26,939.1	\$421,541.7	
Allen	1	SNCR	2003	\$177.3	\$162.4	\$2,884.1	\$364.9	\$0.0	\$0.0	\$0.0	\$3,588.7	
Allen	2	SNCR	2007	\$0.0	\$0.0	\$0.0	\$0.0	\$239.3	\$2,710.6	\$2,772.8	\$5,722.7	
Allen	3	SNCR	2005	\$0.0	\$0.0	\$215.7	\$2,584.1	\$4,091.5	\$32.5	\$0.0	\$6,923.9	
Allen	4	SNCR	2006	\$0.0	\$0.0	\$0.0	\$217.9	\$1,122.2	\$4,258.0	\$224.3	\$5,822.4	
Allen	5	SNCR	2008	\$0.0	\$0.0	\$98.9	\$164.6	\$122.3	\$22.7	\$5,383.9	\$5,792.4	
Buck	3	Burner	2007	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$614.5	\$3,604.3	\$4,218.9	
Buck	3	Classifier	2007	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$309.9	\$309.9	
Buck	4	Burner	2007	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$358.3	\$2,458.5	\$2,816.8	
Buck	4	Classifier	2007	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$165.0	\$165.0	
Buck	5	SNCR	2006	\$0.0	\$0.0	\$0.0	\$268.2	\$345.9	\$4,836.8	\$549.1	\$6,000.0	
Buck	6	SNCR	2006	\$0.0	\$0.0	\$0.0	\$265.8	\$335.3	\$3,814.2	(\$533.6)	\$3,881.7	
Dan River	1	Burner	2008	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$2,762.6	\$2,762.6	
Dan River	1	Classifier	2008	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$182.1	\$182.1	
Dan River	2	Burner	2006	\$0.0	\$0.0	\$0.0	\$0.0	\$775.4	\$1,693.6	\$255.9	\$2,725.0	
Dan River	2	Classifier	2005	\$0.0	\$0.0	\$0.0	\$0.0	\$130.8	\$0.0	\$0.0	\$130.8	
Dan River	3	Burner	2006	\$7.5	\$162.3	\$22.2	\$512.8	\$679.0	\$1,441.4	\$254.7	\$3,080.0	
Dan River	3	Classifier	2005	\$0.0	\$0.0	\$0.0	\$0.0	\$184.3	\$0.0	\$0.0	\$184.3	
Marshall	1	SNCR	2006	\$0.0	\$0.0	\$0.8	\$167.2	\$1,418.4	\$2,106.3	\$157.2	\$3,849.9	
Marshall	2	SNCR	2007	\$0.0	\$0.0	\$197.6	\$185.4	\$778.3	\$2,760.7	\$2,328.1	\$6,250.1	
Marshall	3	SNCR	2005	\$0.0	\$0.0	\$1,577.4	\$652.1	\$2,042.4	\$32.0	\$0.0	\$4,303.9	
Marshall	4	SNCR	2007	\$0.0	\$0.0	\$0.0	\$0.0	\$43.3	\$2,613.6	\$543.4	\$3,200.2	
Riverbend	4	SNCR	2007	\$0.0	\$0.0	\$0.0	\$45.6	\$474.3	\$1,082.2	\$2,681.3	\$4,283.4	
Riverbend	5	Burner	2005	\$362.8	\$284.3	\$2.8	\$2,313.4	\$180.0	\$0.0	\$0.0	\$3,143.3	
Riverbend	5	Classifier	2005	\$0.0	\$0.0	\$0.0	\$159.6	\$0.0	\$0.0	\$0.0	\$159.6	
Riverbend	5	SNCR	2008	\$0.0	\$0.0	\$0.0	\$1.5	\$321.7	\$1,474.6	\$3,194.5	\$4,992.3	
Riverbend	6	Burner	2005	\$144.0	\$416.1	\$12.2	\$510.4	\$2,086.4	\$0.0	\$0.0	\$3,179.1	
Riverbend	6	Classifier	2005	\$0.0	\$0.0	\$0.0	\$0.0	\$189.4	\$0.0	\$0.0	\$189.4	
Riverbend	6	SNCR	2006	\$0.0	\$0.0	\$0.0	\$1.5	\$340.3	\$3,454.1	\$1,173.8	\$4,969.8	
Riverbend	7	SNCR	2006	\$0.0	\$0.0	\$0.0	\$48.5	\$485.8	\$3,939.0	\$849.3	\$5,322.5	
Subtotals:				\$692.4	\$1,024.2	\$18,424.9	\$106,834.5	\$346,420.0	\$427,984.4	\$1,063,879.7	\$1,965,260.2	
NC-CAP Program Total ¹ :										\$1,965,260.2		

SO₂

NO_x

¹ The NC-CAP Program forecast excludes AFUDC associated with capital expenditures yet to be amortized



March 30, 2007

FILED

MAR 30 2007

Clerk's Office
N.C. Utilities Commission

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 2006 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,

A handwritten signature in black ink, appearing to read 'Len S. Anthony', written over a large, stylized flourish.

Len S. Anthony
Deputy General Counsel-Regulatory Affairs

LSA:mhm

Attachment

232822



March 30, 2007

Mr. William G. Ross, Jr.
Secretary
North Carolina Department of Environment and Natural Resources
1601 Mail Service Center
Raleigh, NC 27699-1601

Dear Secretary Ross:

Bill

Progress Energy Carolinas, Inc. (PEC, Company) submits the attached report for calendar year 2006 regarding the compliance status with the provisions of the North Carolina Clean Smokestacks Act (Act).

As you know, 2007 is a significant year for the Clean Smokestacks Act – the first year in which the nitrogen oxides (NO_x) emissions cap is effective. Beginning this year, the Company's annual NO_x emissions from its coal units in North Carolina cannot exceed 25,000 tons. We have developed plans and processes to assure we meet the requirement, and we are on track to achieve this milestone.

While the Act established stringent NO_x and sulfur dioxide (SO₂) emissions limits from coal-fired power plants, it also allowed the affected utilities to determine how to meet the emissions limitations. We regularly review and refine our compliance strategy, weighing a number of factors such as system load projections, expected fuel selection, available control equipment, and anticipated performance and costs of emissions controls. For example, since our last filing, we have continued our evaluation of Furnace Sorbent Injection (FSI) technology. FSI may offer a more cost-effective compliance solution for our Cape Fear Plant than the original plan to use scrubbers. We plan to test the FSI technology at our Robinson Plant in Florence, S.C., in fall 2007. Since Robinson Unit 1 is similar in design to the Cape Fear units, we believe that the FSI test will indicate whether this technology will be effective at Cape Fear. We are happy to provide you and your staff more detail about our plans and the test results.

We appreciate the excellent work of the Department staff, particularly those in the Air Quality and Water Quality divisions, who support our efforts to complete the projects in a timely manner to assure compliance with the Act's requirements. We look forward to continuing our positive working relationship to facilitate fulfillment of the Company's obligations with this important law.

Please don't hesitate to contact me at (919) 546-3775 if you have any questions.

Sincerely,

A handwritten signature in black ink, appearing to read "Caroline Choi". The signature is fluid and cursive, with a long horizontal stroke at the end.

Caroline Choi
Director, Energy Policy and Strategy

c: North Carolina Utilities Commission
Keith Overcash, DAQ
Alan Klimek, DWQ

VERIFICATION

STATE OF NORTH CAROLINA)
)
COUNTY OF WAKE)

NOW, BEFORE ME, the undersigned, personally came and appeared,
E. Michael Williams, who first duly sworn by me, did depose and say:

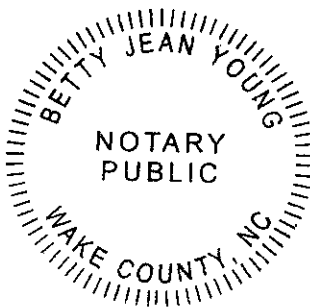
That he is E. Michael Williams, Senior Vice President-Power
Operations of Carolina Power & Light Company, d/b/a Progress Energy
Carolinas, Inc.; he has the authority to verify the foregoing Progress Energy
Carolinas, Inc. North Carolina Clean Smokestacks Act Calendar Year 2006
Progress Report; that he has read said Report and knows the contents
thereof; are true and correct to the best of his knowledge and beliefs.

**E. Michael Williams
Senior Vice President-Power Operations
Progress Energy Carolinas, Inc.**

Subscribed and sworn to me
this 28th day of March, 2007.

Notary Public

*My Commission expires:
October 5, 2008*



Progress Energy Carolinas, Inc. (PEC)
North Carolina Clean Smokestacks Act
Calendar Year 2006 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 (NO_x) and sulfur dioxide (SO₂) 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 (NO_x) and sulfur dioxide (SO₂) 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, 2007. We continue to evaluate various design, technology and generation options that could affect our future compliance plans.

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 2006, Progress Energy Carolinas, Inc. incurred actual capital costs of \$272,819,000.

Asheville

We successfully placed in service the wet scrubber on Asheville Unit 2 in May 2006. A significant amount of work was performed at the Asheville plant in 2005 and 2006 in order to accomplish this milestone. This work included the installation of electrical power and control cables and circuits, piping, pumps, valves, oxidation air compressors, instruments and controls, agitators, absorber tower outlet hood, spray headers, trays and other tower internals. Work efforts also included completing ductwork from the precipitator to the scrubber tower and from the scrubber tower to the stack. The stack liner was connected in 2006. Mechanical and electrical work for the Unit 1 SCR was completed in preparation for placing the SCR into service in spring 2007.

Lee

We completed procurement and installation of the low-NOx burners for Unit 2, placing them in service in 2006. We also completed design, procurement and installation of the Rotamix equipment for NOx control at Unit 3. Construction activities related to Unit 3 Rotamix concluded in 2006, with operational status expected in early 2007.

Mayo

Contracts for the absorber tower and chimney were executed, along with contracts for the overall engineering and construction. Engineering and design work continued throughout the year, and in mid-October contractors mobilized and began construction activities. Long-lead procurement activities continued in order to ensure timely receipt of equipment on-site in support of a spring 2009 in-service date. During the fourth quarter of 2006, on-site activities focused on excavation and backfill of the scrubber island area, installation of rebar, and placement of base slabs for the auxiliary and startup transformers and bus supports.

Roxboro

Construction work for the scrubber project continued on the four units in 2006. In the Common area, installation of the pipe bridge was completed as well as installation of the equipment in the limestone prep building and gypsum dewatering building. The limestone unloading pit was completed, and work was started on installation of conveyors. The limestone slurry storage tanks, vacuum filter feed tanks, filtrate tanks, service water tanks, blow-down tank, and emergency storage tank were completed as well as the electrical equipment building and the oxidation air blower building. Commissioning began on most of the common systems in support of the Unit 2 outage scheduled for spring 2007. Specific unit construction activities completed include the following:

Unit 1

Significant construction included completion of foundations for the absorber, recycle pump house, primary hydro cyclone tank, and electrical building.

Unit 2

Significant construction included completion of the recycle pump house, final assembly of the absorber discharge to the stack, installation of the induced draft fans and associated flue gas ducting, installation of the hydro cyclone tank, and installation of the transformers. In addition, we started commissioning Unit 2 systems in preparation for the spring 2007 outage during which time the final scrubber tie-in will be completed and the scrubber placed into service.

Unit 3

Significant construction included starting installation of ducting from the existing stack to the new induced draft fans. Construction was started on foundations for duct support steel from the new induced draft fans to the absorber. We continued installation of the absorber and started assembly of the booster fan. Work also started on fabrication of the new flue gas ducting.

Unit 4

Significant construction included completion of the absorber and the start of erection of the recycle pump house and primary hydro cyclone tank.

Wastewater Project

Significant construction activity included starting the wastewater settlement and flush ponds which are scheduled for completion in early 2007. In December, we issued a request for bids on construction of the bioreactor facilities.

Sutton

We completed procurement and installation of the low-NOx burners for Unit 2 and placed them in service during 2006.

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

Progress Energy Carolinas, Inc. amortized \$140 million in 2006.

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 2006 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 between \$1.1 and \$1.4 billion. The current point estimate is \$1.355 billion, a slight decrease from the 2006 cost estimate of \$1.362 billion. Prior reports have discussed the cost impact of project scope changes and the impact of significant increases in the cost of materials and labor which have impacted construction projects across the Southeast. These factors continued to impact the cost of the projects during 2006 as indicated by the current estimates for Roxboro, Mayo, and Sutton.

The current estimates also reflect updates to PEC's compliance plan based on the expected performance of the scrubbers at Asheville, Roxboro, and Mayo, current resource plans, current fuel forecasts, and advancements in SO₂ removal technology. 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." We regularly review and refine our compliance strategy, weighing a number of factors such as system load projections, expected fuel selection, available control equipment, anticipated performance and costs of emissions controls, and knowledge of and experience with emissions control options.

For example, since our last filing, PEC has continued its evaluation of the potential to use Furnace Sorbent Injection (FSI) technology at our Cape Fear Plant. FSI technology may offer a more cost-effective compliance solution for Cape Fear Plant than the original plan to use scrubber technology. Use of the FSI technology also eliminates the need for a costly wastewater treatment system. We plan to test the FSI technology at PEC's Robinson Unit 1 in fall 2007. Since Robinson Unit 1 is similar in design to the Cape Fear units, the Robinson test will indicate whether the use of this technology will be effective at Cape Fear.

The current compliance plan also contemplates the use of a dry scrubber at Sutton Unit 3. A dry scrubber at that unit represents a more cost effective compliance solution and also eliminates the need for a costly wastewater treatment system.

Lastly, the compliance plan calls for the use of Rotamix technology with combustion optimization at Lee 3 for NO_x control. Prior plans had contemplated the use of rotating opposed-fired air (ROFA) and Rotamix technology at that unit. Engineering studies

completed in early 2006 indicated that combustion optimization combined with the existing Low-NOx burners with overfired-air would provide benefits equivalent to the ROFA and at less cost.

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.

Progress Energy Carolinas, Inc. applied for the following permits in 2006:

Asheville Plant

Air Permit

- Notification of 502(b)(10) permit change for SO₃ mitigation system submitted April 5, 2006. Notification that the permit change will be treated as an “off permit change” rather than a 502(b)(10) received June 30, 2006.

Erosion and Sedimentation Control Plan

- Several updates were submitted. Rev J for the construction of the de-mineralized pipe, pump and duct bank was approved in January 2006.

Roxboro Plant

Air Permit

- An update for coal handling and limestone handling was issued on February 9, 2006. An additional update was requested on November 10, 2006. The revised air permit incorporating this revision was issued on March 15, 2007.
- Revisions to address fugitive emissions of hydrogen sulfide from the wastewater treatment system were approved June 23, 2006.

NPDES Permit

- An Authorization to Construct (ATC) for the gypsum settling pond was received March 3, 2006.
- An ATC for the bioreactor was received July 5, 2006.

Erosion and Sedimentation Control Plan

Several updates were submitted:

- Rev K for the haul road, transformer, main plant area wastewater pipe trench and gypsum conveyor foundations was submitted January 18, 2006, and approved February 10, 2006.
- Rev L for burying the wastewater pipeline was submitted April 19, 2006, and approved May 2, 2006.
- Rev M for increased disturbed areas for wastewater pond construction borrow and stockpile area, construction parking area, and construction road widening was submitted June 7, 2006, and approved June 26, 2006.

Mayo Plant

Air Permit

- Construction permit application for the flue gas desulfurization system was submitted May 25, 2006, and the permit was issued July 28, 2006.

NPDES Permit

- Permit modification for wastewater treatment system was received September 14, 2006.

Erosion and Sediment Control Plan

- Rev D for the installation of the flue gas desulfurization system was approved November 9, 2006.

Lee Plant

Air Permit

- A prevention of significant deterioration (PSD) permit for the installation of low NOx burners was approved March 21, 2006.
- Construction permit application for the installation of the Rotamix System for NOx control was submitted April 5, 2006, and was approved June 30, 2006.

NPDES Permit

- A permit application amendment for the Rotamix Urea Injection System on Unit 3 was submitted May 15, 2006. A revised amendment was then submitted October 24, 2006, and approved December 18, 2006.

- 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.**

Asheville

Construction activities will continue in 2007 for the Asheville Unit 1 SCR. Construction activities related to installation of electrical power, control cables and circuits, piping, instruments and controls will occur. Installation of the additional urea-to-ammonia system modifications for Unit 1 SCR is planned. The Unit 1 SCR is scheduled to be operational in spring 2007.

Lee

For Unit 3, we will complete tuning of the Rotamix equipment for NOx emissions control and place the system in service in early 2007.

Mayo

During 2007, construction activities will focus on completion of the chimney and absorber foundations and subsequent erection of the absorber and chimney structures. Concurrently, equipment such as pumps, ball mills, induced draft fans, and conveyors will begin to arrive on-site. In support of major equipment installation, numerous foundations will be placed during 2007 including foundations for the recycle pump house, limestone prep and dewatering buildings. Engineering activities will continue during 2007, with the focus during the latter half of the year shifting from scrubber to wastewater treatment process flows and equipment.

Roxboro

For 2007, significant construction activities planned in the Common area include completion of the limestone conveyors. Specific unit activities are described below:

Unit 1

Significant construction activities planned include construction of Unit 1 absorber, electrical building, primary hydro-cyclone tank, recycle pump house, and induced draft fan foundations.

Unit 2

Significant activities planned include completion of commissioning and startup activities to support the tie-in of the new flue gas duct to the absorber. The scrubber will be placed in service in spring 2007.

Unit 3

Significant construction activities planned include completing the installation of the booster fans, final assembly of flue gas duct from the existing stack to the absorber, and the start of duct insulation. Additionally, work on the foundation for the recycle pump house will start in spring 2007. The expected start-up of the scrubber is spring 2008.

Unit 4

Significant construction activities planned include completion of the absorber internals, installation of all equipment associated with the recycle pump house, and installation of booster fans and associated flue gas ducting from the existing stack to the absorber. Commissioning of Unit 4 equipment in support of scrubber start-up planned for fall 2007 will be completed as well.

Wastewater

Significant construction activities planned for wastewater include completion of the wastewater settlement and flush ponds, construction and commissioning of the bioreactor facilities, and completion of the wastewater piping from the plant.

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.

We appreciate the collaborative efforts the DAQ and DWQ staff has made to assure our construction and installation schedules remain on track. However, the potential for longer permit processing times continues to be a serious concern for future projects. PEC wishes to work collaboratively with the Department to prevent delays from occurring.

The following permit applications and permit approvals are anticipated for 2007:

Asheville Plant

Air Permit

- Current opacity rules pre-date saturated gas streams from wet scrubbers and require representative measurements where condensed water vapor is not present. We will request revisions to the permit and underlying rules for opacity monitoring to include references to current federal regulations that exempt units with wet scrubbers from continuous opacity monitoring requirements.

NPDES Permit

- A request for Sampling Reduction at the internal Outfall 005 (treated FGD wet scrubber wastewater) was submitted January 25, 2007. A response is expected by end of first quarter.

Roxboro Plant

Air Permit

- A permit application for the emergency fire water diesel engine was submitted in January 2007. Authorization to construct the fire water diesel engine has been received; however, the operating permit must be received to support operation of the Unit 2 scrubber during the second quarter 2007.
- Current opacity rules pre-date saturated gas streams from wet scrubbers and require representative measurements where condensed water vapor is not present. We will request revisions to the permit and underlying rules for opacity monitoring to include references to current federal regulations that exempt units with wet scrubbers from continuous opacity monitoring requirements.

Mayo Plant

NPDES Permit

- An ATC request for the wastewater treatment system is expected to be submitted in the first quarter with response desired by the end of the second quarter.
- An ATC request for a new oil/water separator is expected to be submitted by the end of the first quarter with response expected by the end of the third quarter.

Erosion and Sedimentation Control Plan

- Rev F. for the increase in disturbed land (from 35 acres to 98 acres) for the flue gas desulfurization system was submitted January 29, 2007. Additional plan revisions will be necessary as construction plans are developed.

Lee Plant

Air Permit

- A Title V permit application is due to be submitted in July 2007 in accordance with permit requirements associated with the low-NOx burner installation.

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

During 2006, performance testing of the SO₂ scrubbers at Asheville Units 1 and 2 was completed. The testing confirmed that the scrubbers had achieved their performance guarantee of 97% removal efficiency.

During 2006, performance testing of the low-NOx burners (LNBS) at Sutton Unit 2 and Lee Unit 2 was completed. The testing demonstrated that the LNBS met their respective performance guarantees.

9. The number of tons of oxides of nitrogen (NOx) and sulfur dioxide (SO₂) 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 total calendar year 2006 emissions from the affected coal-fired Progress Energy Carolinas units are:

NOx 46,501 tons
SO₂ 175,226 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 2006, 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, 2007

On June 20, 2002, Governor Easley signed into law SB1078, which caps emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO₂) from utility owned coal-fired power plants located in North Carolina. Under the law, G.S. § 143-215.107D, PEC's annual NO_x emissions must not exceed 25,000 tons beginning in 2007 and annual SO₂ emissions must not exceed 100,000 tons beginning in 2009 and 50,000 tons beginning in 2013. These caps represent a 56% reduction in NO_x emissions from 2001 levels and a 74% reduction in SO₂ emissions from 2001 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 has been evaluating and installing NO_x emissions controls on its coal-fired power plants since 1995 in order to comply with Title IV of the Clean Air Act and the NO_x SIP Call rule adopted by the Environmental Management Commission (EMC). Substantial NO_x emissions reductions have already been achieved (46,500 tons of NO_x in 2006 compared with 112,000 tons in 1997) and further reductions will ensure compliance with the Clean Smokestacks Act's 25,000 ton cap in calendar year 2007. This target will be achieved with a mix of combustion controls (which minimize the formation of NO_x), such as low-NO_x burners and over-fire air technologies, and post-combustion controls (which reduce NO_x 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 name plate generation capacity, installed NO_x control technologies and those planned for installation. As technologies evolve or other circumstances change, a different mix of controls may be selected. Attachment 2 also projects annual NO_x emissions on a unit-by-unit basis based on the energy demand forecast and expected efficiencies of the NO_x emissions controls employed. 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.

Sulfur Dioxide Emissions Control Plan

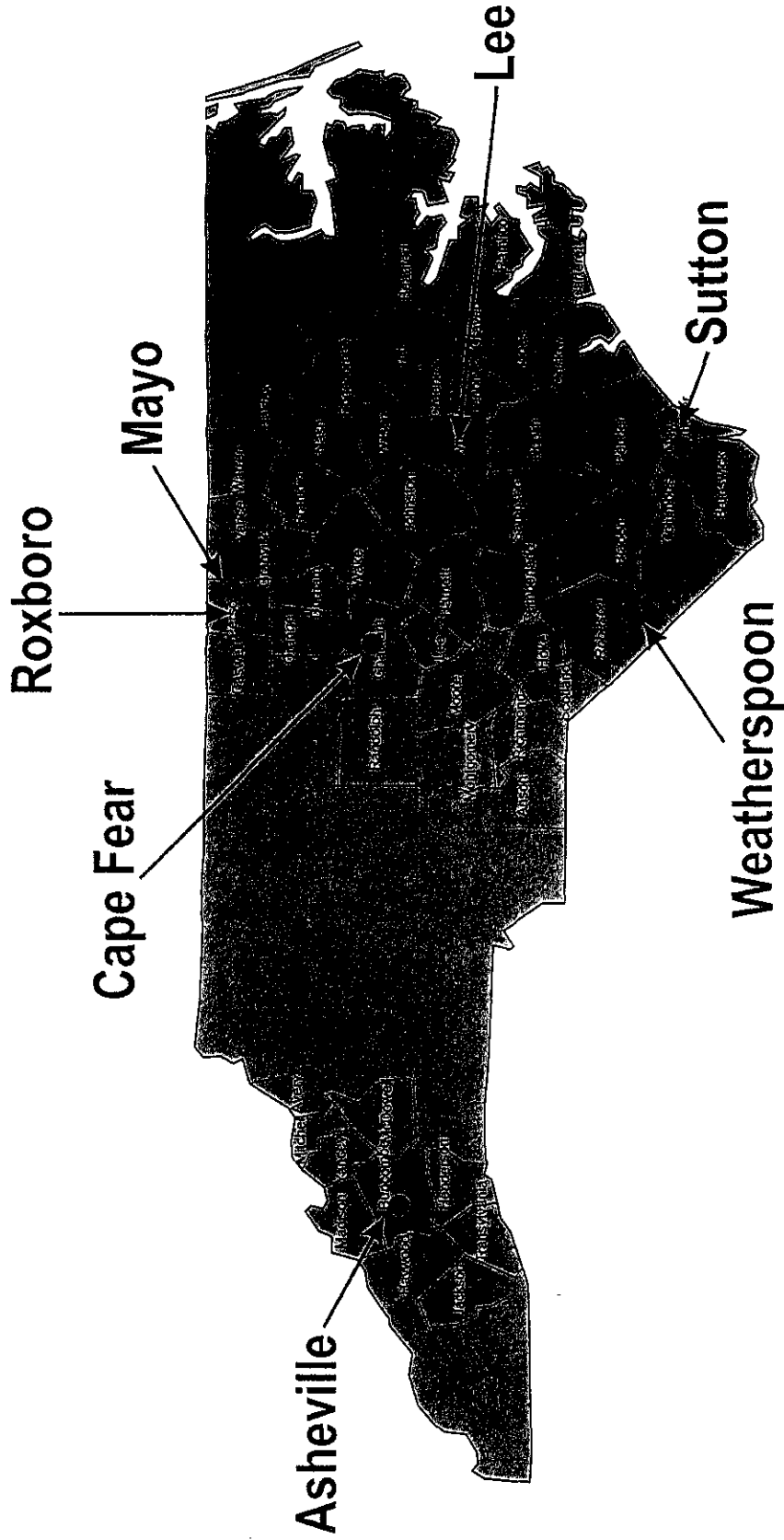
PEC will be installing wet flue gas desulfurization systems (FGD or “scrubbers”) to remove 97% of the SO₂ from the flue gas of its Asheville, Roxboro and Mayo boilers. Since our last filing, PEC has continued its evaluation of the potential to use Furnace Sorbent Injection (FSI) technology at our Cape Fear Plant. FSI technology may offer a more cost-effective compliance solution for the Cape Fear Plant than the original plan to use scrubber technology. Use of the FSI technology also eliminates the need for a costly wastewater treatment system. We plan to test the FSI technology at PEC’s Robinson Unit 1 in fall 2007. Since Robinson Unit 1 is similar in design to the Cape Fear units, the Robinson test will indicate whether the use of this technology will be effective at Cape Fear. The current compliance plan also contemplates the use of a dry scrubber at Sutton Unit 3. A dry scrubber at that unit represents a more cost effective compliance solution and also eliminates the need for a costly wastewater treatment system.

Wet scrubbers produce unique waste and byproduct streams. Issues related to wastewater permitting and solid waste disposal are being addressed for each site. PEC is treating the scrubber wastewater stream at the Asheville Plant using an innovative constructed wetlands treatment system to ensure compliance with discharge limits. A bioreactor technology will be used for the Roxboro and Mayo Plants.

A contract has been executed with a gypsum product end-user that will construct a facility near the Roxboro Plant to use the synthetic gypsum produced by the Roxboro and Mayo Plants for the manufacture of drywall products. PEC also has entered into an agreement that enables PEC to market and sell synthetic gypsum produced at the Asheville Plant.

Attachment 3 details PEC’s North Carolina coal-fired electric generating units, their *name plate generation capacity, installed SO₂ control technologies and those planned for installation*. As technologies evolve or other circumstances change, a different mix of controls may be selected. Attachment 3 also projects annual SO₂ emissions on a unit-by-unit basis based on the energy demand forecast and expected efficiencies of the SO₂ 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 2007 NOx Control Plan for North Carolina Coal-fired Units

Unit	MW Rating	Control Technology	Operation Date ¹	Projected NOx Tons, 2007 ²
Asheville 1	198	LNB/AEFLGR/SCR	2007	1,304
Asheville 2	194	LNB/OFA/SCR		377
Cape Fear 5	143	ROFA/ROTAMIX		627
Cape Fear 6	173	ROFA/ROTAMIX		930
Lee 1	79	WIR		909
Lee 2	76	LNB	2006	740
Lee 3	252	LNB/ROTAMIX	2007	1,855
Mayo 1	745	LNB/OFA/SCR		1,712
Roxboro 1	385	LNB/OFA/SCR		1,067
Roxboro 2	670	TFS2000/SCR		1,021
Roxboro 3	707	LNB/OFA/SCR		2,092
Roxboro 4	700	LNB/OFA/SCR		1,999
Sutton 1	97	SAS		960
Sutton 2	106	LNB	2006	1,282
Sutton 3	410	LNB/ROFA/ROTAMIX		3,936
Weatherspoon 1	49			881
Weatherspoon 2	49			951
Weatherspoon 3	78	WIR		1,205
Total	5,111			23,848

AEFLGR = Amine-Enhanced Flue Lean Gas Reburn
LNB = Low NOx Burner
SNCR = Selective Non-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 Improve Air Quality/Electric Utilities Act only (shown in bold).

² Unit by unit emissions are illustrative only and specific emissions limits should not be inferred. Actual emissions in 2007 may be different from unit to unit.

Attachment 3: PEC's 2007 SO₂ Control Plan for North Carolina Coal-Fired Units

Unit	MW Rating	Technology	Operation Date	Projected SO ₂ Tons, 2009 ¹	Projected SO ₂ Tons, 2013
Asheville 1	198	Scrubber	2005	379	360
Asheville 2	194	Scrubber	2006	405	398
Cape Fear 5	143	FSI	2011	7,004	3,379
Cape Fear 6	173	FSI	2012	8,629	4,300
Lee 1	79			2,925	2,504
Lee 2	76			2,883	2,470
Lee 3	252			11,384	6,892
Mayo 1	745	Scrubber	2009	9,406	1,532
Roxboro 1	385	Scrubber	2008	742	960
Roxboro 2	670	Scrubber	2007	978	1,260
Roxboro 3	707	Scrubber	2008	1,102	1,521
Roxboro 4	700	Scrubber	2007	1,376	1,402
Sutton 1	97			4,383	4,470
Sutton 2	106			4,335	4,353
Sutton 3	410	Scrubber	2012	17,907	1,019
Weatherspoon 1	49			1,599	1,778
Weatherspoon 2	49			1,580	1,701
Weatherspoon 3	78			2,917	3,079
Total	5,111			79,934	43,378

FSI = Furnace Sorbent Injection

¹ Unit by unit emissions are illustrative only and specific emissions limits should not be inferred. Actual emissions in 2009 and 2013 may be different from unit to unit.

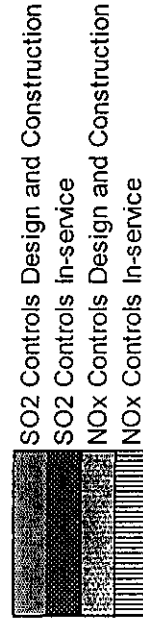
Appendix B
PEC's Actual Costs Through 2006 and Projected Costs Through 2013
for Clean Smokestacks Act Compliance (in thousands)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Ashville 1 FGD	\$ 100	\$ 9,652	\$ 31,574	\$ 35,769	\$ 3,930	\$ -1,132	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 81,894
Ashville 1 SCR	\$ 0	\$ 0	\$ 688	\$ 1,423	\$ 14,608	\$ 19,063	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 35,783
Ashville 2 FGD	\$ 100	\$ 7,742	\$ 28,390	\$ 24,238	\$ 11,701	\$ -992	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 71,180
Ashville FGD Common	\$ 467	\$ 0	\$ 0	\$ 0	\$ 0	\$ -467	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Mayo 1 FGD	\$ 187	\$ 0	\$ 276	\$ 644	\$ 22,794	\$ 102,487	\$ 90,669	\$ 19,894	\$ 0	\$ 0	\$ 0	\$ 0	\$ 236,950
Roxboro FGD Common	\$ 403	\$ 5,561	\$ 10,033	\$ 51,717	\$ 72,934	\$ 20,277	\$ 22,155	\$ 495	\$ 0	\$ 0	\$ 0	\$ 0	\$ 183,576
Roxboro 1 FGD	\$ 0	\$ 0	\$ 0	\$ 3,155	\$ 12,164	\$ 19,380	\$ 62,807	\$ 884	\$ 0	\$ 0	\$ 0	\$ 0	\$ 98,370
Roxboro 2 FGD	\$ 120	\$ 3,574	\$ 6,848	\$ 10,782	\$ 46,014	\$ 19,166	\$ 1,123	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 107,627
Roxboro 3 FGD	\$ 0	\$ 0	\$ 244	\$ 10,628	\$ 36,661	\$ 44,574	\$ 13,891	\$ 255	\$ 0	\$ 0	\$ 0	\$ 0	\$ 111,251
Roxboro 4 FGD	\$ 0	\$ 0	\$ 0	\$ 9,075	\$ 28,550	\$ 65,099	\$ 9,346	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 103,279
Cape Fear SPSI	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 5,120	\$ 8,152	\$ 9,844	\$ 0	\$ 0	\$ 23,116
Cape Fear 6 FSI	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 5,573	\$ 8,874	\$ 10,715	\$ 0	\$ 25,163
Lee 3/Rotamix	\$ 0	\$ 0	\$ 0	\$ 198	\$ 6,424	\$ 3,197	\$ 27	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 9,846
Sutton 3 FGD	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 10,378	\$ 60,142	\$ 61,607	\$ 4,211	\$ 6,610	\$ 182,948
Lee 2 UNB	\$ 0	\$ 0	\$ 133	\$ 279	\$ 1,886	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 2,292
Sutton 2 UNB	\$ 0	\$ 0	\$ 0	\$ 236	\$ 1,900	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 2,136
Total without Wastewater	\$ 1,377	\$ 26,528	\$ 80,187	\$ 168,118	\$ 259,566	\$ 281,860	\$ 205,019	\$ 37,026	\$ 73,867	\$ 80,325	\$ 54,926	\$ 6,610	\$ 1,275,410
Ashville WWI	\$ 0	\$ 0	\$ 0	\$ 12,365	\$ 1,289	\$ 200	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 13,853
Mayo WWI	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 6,117	\$ 10,813	\$ 4,638	\$ 0	\$ 0	\$ 0	\$ 0	\$ 21,568
Roxboro WWI	\$ 0	\$ 0	\$ 0	\$ 791	\$ 11,965	\$ 28,250	\$ 2,708	\$ 32	\$ 0	\$ 0	\$ 0	\$ 0	\$ 43,746
Sutton WWI	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Total Wastewater Treatment	\$ 0	\$ 0	\$ 0	\$ 13,156	\$ 13,253	\$ 34,567	\$ 13,521	\$ 4,670	\$ 0	\$ 0	\$ 0	\$ 0	\$ 79,167
Total/Clean Smokestacks Act	\$ 1,377	\$ 26,528	\$ 80,187	\$ 181,274	\$ 272,819	\$ 316,427	\$ 218,540	\$ 41,696	\$ 73,867	\$ 80,325	\$ 54,926	\$ 6,610	\$ 1,354,577
Estimated ARUDC						\$ 710	\$ 11,720	\$ 6,470	\$ 1,332	\$ 2,857			

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

Appendix C PEC's Clean Smokestacks Act Compliance Plan

Plant Project	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Ashville 1 FGD											
Ashville 1 SCR											
Ashville 2 FGD											
Mayo 1 FGD											
Roxboro 1 FGD											
Roxboro 2 FGD											
Roxboro 3 FGD											
Roxboro 4 FGD											
Cape Fear 5 FSI											
Cape Fear 6 FSI											
Lee 3 Rotamix											
Sutton 3 FGD											
Lee 2 LNB											
Sutton 2 LNB											



Schedule as of 4/1/2007

**REPORT OF THE PUBLIC STAFF ON COSTS
INCURRED AND AMORTIZED BY DUKE ENERGY CAROLINAS, LLC
IN COMPLIANCE WITH SESSION LAW 2002-4**

Docket No. E-7, Sub 718

May 25, 2007

Section 14 of Session Law 2002-4 ("the Clean Smokestacks Act" or "the Act") requires the Department of Environment and Natural Resources ("DENR") and the Utilities Commission ("Commission") to report, by June 1 of each year, on the implementation of the Act to the Environmental Review Commission and the Joint Legislative Utility Review Committee. The May 30, 2003, report of DENR and the Commission states that the Public Staff will audit the books and records of the investor owned utilities on an ongoing basis in regard to the costs incurred and amortized in compliance with the Act. The Public Staff has undertaken such a review, focusing on the verification of costs related to complying with the Act, the amortization of those costs, and the operating results of emission reduction equipment installed by Duke Energy Carolinas, LLC ("Duke"). This report presents the Public Staff's findings for the twelve months ended December 31, 2006.

I. Compliance Plan Summary

Duke's original plan to install Selective Non-catalytic Reduction ("SNCR") technology to remove NO_x and flue-gas desulfurization technology ("scrubbers") to remove SO₂ to comply with the Act remains practically the same with only minor changes to the compliance schedule and plan. Duke has indicated that it is installing Selective Catalytic Reduction ("SCR") technology at its Marshall Unit 3 to comply with other regulatory requirements for NO_x reductions in the Charlotte region. The new SCR replaces the SNCR equipment that was installed at Marshall Unit 3 to comply with the Act. Duke has redeployed the SNCR equipment from Marshall Unit 3 to Unit 4. The Public Staff is not aware of other similar modifications to the compliance plan.

II. Environmental Compliance Costs

Duke is required by the Act to submit a report to the Commission and to DENR on or before April 1 of each year containing its actual environmental compliance costs incurred during the previous calendar year. As defined by G.S. 62-133.6(a)(2), "environmental compliance costs" include only capital costs.

In its Compliance Plan Annual Update for 2007 ("2007 Compliance Update"), Duke reported that its actual environmental compliance costs in calendar year 2006 were \$427,984,429. The cumulative environmental compliance costs incurred by Duke through 2006 were \$901,380,056, as follows:

Year 2001	\$ 692,433
Year 2002	1,024,223
Year 2003	18,424,921
Year 2004	106,834,479
Year 2005	346,420,000
Year 2006	<u>427,984,429</u>
Total	\$901,380,485

Duke's expenditures to date involve emission reduction technologies at its Allen, Belews Creek, Buck, Cliffside, Dan River, Marshall, and Riverbend facilities. Environmental compliance costs were incurred primarily for engineering, equipment procurement, contracting, construction, and field performance testing.

As part of its review, the Public Staff requested information from Duke on the project costs, invoices documenting costs, and the purpose of the costs. Duke provided project cost sheets delineating actual project costs by year into the following categories: (1) direct labor costs; (2) labor loads; (3) contract costs; (4) material costs; (5) overhead costs; and, (6) other costs. These costs are as follows:

Direct Labor	\$ 4,579,146
Labor Loads	1,306,856
Contracts	407,124,522
Materials	1,419,497
Overheads	213,822
Other	<u>13,340,586</u>
Total	\$427,984,429

The project cost sheets were supported by project detail reports that incorporated all expenditures for a particular category or group. The Public Staff selected invoices in each category from the detailed spreadsheets and requested Duke to provide specific information on the selected costs. The Public Staff also had discussions with Duke personnel to gain a better understanding of the cost items charged to each specific project. Duke provided documentation to support each selected cost.

Duke has estimated its environmental compliance costs at \$1,965,260,200, as set forth on Exhibit C in its 2007 Compliance Update, compared to an estimate of \$1,731,510,400 filed as part of Duke's 2006 update. The 2007 projection represents an increase of \$465,260,200 or 31% over Duke's original estimate of \$1,500,000,000, as set forth in G.S. 62-133.6(b). According to Duke personnel, several factors have contributed to the increase in the estimate, including an industry-wide ramp-up of similar environmental compliance work nationwide and its effect on labor availability, and increases in the prices for materials.

Duke is using third party verification to ensure that its fixed price estimates for each project are consistent with market prices. The Public Staff will review the

verifications and will continue to monitor the factors causing increases in the environmental compliance cost estimates.

III. Amortization of Costs

In Section 9 of the Act [G.S. 62-133.6(b)], the investor owned utilities are allowed to accelerate the recovery of their estimated environmental compliance costs over a seven-year period, beginning January 1, 2003, and ending December 31, 2009. The statute requires that a minimum of 70% of the environmental compliance costs be amortized before December 31, 2007, when the rate freeze period expires. In Duke's case, this amount is \$1,050,000,000. The annual levelized amount is \$214,285,714. The maximum amount that can be amortized in any given year is 150% of the annual levelized environmental compliance costs or \$321,428,000.

Using the protocols established by the Act and subsequent Commission orders, Duke reported that its environmental compliance costs amortization for 2006 was \$225,236,000. The Public Staff reviewed Duke's quarterly amortization filings and supporting journal entries and concluded that the amounts appear to be accurate. The cumulative amortization to date is \$862,665,142.

IV. Contracts

No contracts were reviewed during this audit period.

V. Site Inspections

On May 8, 2007, the Public Staff conducted an inspection of Duke's Marshall Steam Station in Mooresville, North Carolina. All but one of the scrubbers were completed and operational. The remaining scrubber is scheduled for tie-in later by the end of May. All of the related facilities (reagent storage and processing, wastewater disposal system, and byproduct removal) for SNCRs and scrubbers were installed and operational. Once the remaining scrubber is brought online, all of the work intended for the Marshall Steam Station to comply with the Act will have been completed.

The Public Staff will continue to inspect other facilities as Duke implements its compliance plan.

**REPORT OF THE PUBLIC STAFF ON COSTS
INCURRED AND AMORTIZED BY PROGRESS ENERGY CAROLINAS, INC.
IN COMPLIANCE WITH SESSION LAW 2002-4**

Docket No. E-2, Sub 815

May 25, 2007

Section 14 of Session Law 2002-4 ("the Clean Smokestacks Act" or "the Act") requires the Department of Environment and Natural Resources ("DENR") and the Utilities Commission to report, by June 1 of each year, on the implementation of the Act to the Environmental Review Commission and the Joint Legislative Utility Review Committee. The May 30, 2003, report of DENR and the Commission states that the Public Staff will audit the books and records of the investor owned utilities on an ongoing basis in regard to the costs incurred and amortized in compliance with the Act. The Public Staff has undertaken such a review, focusing on the verification of costs related to complying with the Act, the amortization of those costs, and the operating results of emission reduction equipment installed by Progress Energy Carolinas, Inc. ("PEC"). This report presents the Public Staff's findings for the twelve months ended December 31, 2006.

I. Compliance Plan Summary

PEC's original plan to install Selective Catalytic Reduction ("SCR") technology to remove NO_x and flue-gas desulfurization technology ("scrubbers") to remove SO₂ to comply with the Act, remains practically the same with minor changes being made to the compliance schedule and plan.

The scrubber at Asheville Unit 2 was placed into operation in May 2006. The SCR on Asheville Unit 1 is expected to be online in 2007. The Roxboro (Units 1, 3, and 4) and Mayo scrubber construction projects continue with substantial work being done at both facilities. The scrubber for Roxboro Unit 2 started operation in May 2007.

Lee Unit 2 and Sutton Unit 2 initiated operation of low NO_x burners in 2006. Lee Unit 3 is expected to begin operation of a "Rotamix" system in 2007.

PEC is also looking into installing Furnace Sorbent Injection (FSI) technology that promises a lower cost means of SO₂ removal. PEC indicates that testing of similar equipment at its Robinson facility in South Carolina will affect its decision to pursue FSI technology rather than scrubbers at the Cape Fear units.

II. Environmental Compliance Costs

PEC is required by the Act to submit a report to the Commission and to DENR on or before April 1 of each year containing the actual environmental compliance costs

incurred during the previous calendar year. As defined by G.S. 62-133.6(a)2, "environmental compliance costs" include only capital costs.

In its calendar year 2006 Progress Report ("2006 Report"), PEC reported that its actual environmental compliance costs in calendar year 2006 were \$272,819,398. The cumulative environmental compliance costs incurred by PEC through 2006 are \$560,410,636, as follows:

Year 2002	\$ 1,391,731 ¹
Year 2003	26,604,199
Year 2004	78,321,742
Year 2005	181,273,566
Year 2006	<u>272,819,398</u>
Total	\$560,410,636 ²

PEC's expenditures to date involve emission reduction technologies at its Asheville, Mayo, Roxboro, Sutton, and Lee facilities. Environmental compliance costs were incurred for project studies and investigations, engineering, contracting, construction, and equipment acquisition.

As part of its review, the Public Staff requested information from PEC on the project costs, invoices documenting costs, and the purpose of the costs. PEC provided project cost sheets delineating actual project costs by year into the following categories: (1) company labor costs; (2) materials costs; (3) outside services costs; (4) burdens; and (5) other costs. These costs are as follows:

Company Labor	\$ 2,964,099
Material	128,130,618
Outside Services	126,479,796
Labor Loads/Overheads	4,877,740
Other	<u>10,367,145</u>
Total	\$272,819,398

The project cost sheet was supported by detailed spreadsheets for a particular category. The Public Staff selected invoices from the detailed spreadsheets and

¹ Per Appendix B, costs for 2002, 2003, and 2004 are slightly different from the costs reported for those years in previous reports. For 2004, a majority of the difference relates to a Company adjustment to include Asheville wastewater treatment (WWT) costs in the FGD line items for Asheville. In 2005, PEC began reporting WWT project costs separately.

² PEC's estimated and reported environmental compliance costs exclude certain costs attributable to the portions of its Mayo and Roxboro facilities that are owned by the NC Eastern Municipal Power Agency (NCEMPA). According to PEC's FERC Form No. 1 for 2005, PEC entered into an agreement with NCEMPA in 2005 to limit its aggregate cost associated with PEC's environmental compliance costs to approximately \$38,000,000. In a November 2, 2006, filing with the Commission in this docket, PEC stated that its estimated compliance costs have now further increased and that the \$37.9 million cap is \$29.1 million less than NCEMPA's full ownership share of the total Clean Smokestacks costs.

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requested PEC to provide specific information on the selected costs. The Public Staff has had discussions with PEC personnel regarding the cost items charged to projects. PEC has provided documentation to support the selected costs.

PEC has estimated its environmental compliance costs at \$1,354,577,000, as set forth on Appendix B in its 2006 Report. This represents an increase of \$541,577,000 or 66.6% over PEC's original estimate of \$813,000,000, as set forth in G.S. 62-133.6(b).

According to PEC personnel, several factors continue to contribute to the increase in the estimate, including significant increases in the price of skilled labor and materials, increases in equipment costs due to the limited number of suppliers available, and adjustments of future costs based on actual costs of projects already completed or substantially completed.

PEC has previously cited its decision to change the scrubber technology on its units from a dry scrubber to a wet scrubber. This decision has further increased the costs because of the need for wastewater treatment. In its 2006 Report, PEC has indicated that it is now considering a dry scrubber for Sutton Unit 3, and that this represents a more cost effective compliance solution. While no expenditures have been made to date on developing the scrubber for Sutton Unit 3, the Public Staff understands that unit specific criteria, system-wide emission targets, existing scrubber performance, and costs are all factors involved in the decision-making process. The Public Staff will continue to monitor this development.

III. Amortization of Costs

In Section 9 of the Act [G.S. 62-133.6(b)], the investor owned utilities are allowed to accelerate the cost recovery of their estimated environmental compliance costs over a seven-year period, beginning January 1, 2003, and ending December 31, 2009. The statute requires that a minimum of 70% of the environmental compliance costs be amortized before December 31, 2007, when the rate freeze period expires. In PEC's case, this amount is \$569,100,000. The annual levelized amount is \$116,142,857. The maximum amount that can be amortized in any given year is 150% of the annual levelized environmental compliance costs or \$174,214,285.

Using the protocols established by the Act and subsequent Commission orders, PEC reported that its environmental compliance costs amortization for 2006 is \$140,000,000. The Public Staff has reviewed PEC's quarterly amortization filings, as well as the journal entries recorded, and concluded that the reported amounts appear to be accurate. The cumulative amortization to date is \$535,218,808.

IV. Contracts

No contracts were reviewed during this audit period.

V. Site Inspections

On May 21, 2007, the Public Staff conducted a site inspection of PEC's Mayo and Roxboro facilities in Person County, North Carolina. Significant construction is occurring at both facilities. Roxboro Unit 2 is now being scrubbed, with gypsum being temporarily trucked to a holding area until the wallboard facility is completed. The wallboard facility will take ownership of the gypsum once it is conveyed across the intake canal. Most of the other support equipment common to all scrubbers is in place and the remaining units will be placed in service as each unit enters a scheduled outage period over the next two years.

With respect to the Mayo facility, foundation work is progressing on the scrubber itself, the building housing the equipment, and the stack. Construction on limestone handling and gypsum removal facilities has not yet started. PEC plans to truck limestone and gypsum to and from the Mayo facility to the Roxboro facility.

It is the intent of the Public Staff to continue inspections of other coal-fired generating facilities as PEC continues to install emission reduction equipment in its boiler units.